FIRSTENERGY CORP
Form 10-Q
November 04, 2014

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

FORM 10-Q
(Mark One)
þ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes þ No o FirstEnergy Corp. 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 þ No o FirstEnergy Corp. and 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 þ FirstEnergy Corp.

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

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

Yes o No þ FirstEnergy Corp. and FirstEnergy Solutions Corp.

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 OCTOBER 31, 2014
FirstEnergy Corp., $0.10 par value	420,792,515
FirstEnergy Solutions Corp., no par value	7

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

This combined Form 10-Q 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 the other registrant, except that information relating to FirstEnergy Solutions Corp. is also attributed to FirstEnergy Corp.

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.

OMISSION OF CERTAIN INFORMATION

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

Forward-Looking Statements: This Form 10-Q includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements include declarations regarding management's intents, beliefs and current expectations. These statements typically contain, but are not limited to, the terms “anticipate,” “potential,” “expect,” "forecast," "will," "intend," “believe,” “estimate” and similar words. Forward-looking statements involve estimates, assumptions, known and unknown risks, uncertainties and other factors that may cause actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements, 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 in the Competitive Energy Services segment.
- The accomplishment of our regulatory and operational goals in connection with our transmission plan and pending distribution rate cases and the effectiveness of our repositioning strategy.
- The impact of the regulatory process on pending matters in the various states in which we do business including, but not limited to, matters related to rates and pending rate cases, and 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 also 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 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, possible GHG emission, water discharge, and CCR regulations, the potential impacts of CSAPR, and the effects of the EPA's MATS rules including our estimated costs of compliance.
- The uncertainty of the timing and amounts of the capital expenditures that may arise in connection with any litigation, including NSR litigation, or potential regulatory initiatives or rulemakings (including that such expenditures could result in our decision to deactivate or idle certain generating units).
- The uncertainties associated with the deactivation of certain older regulated and competitive fossil units, including the impact on vendor commitments, and the timing thereof as they relate to, among other things, RMR arrangements and 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.

- 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 successfully execute our announced 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 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.

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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. As of January 1, 2014, AE merged with and into FirstEnergy Corp.
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.
CEI	The Cleveland Electric Illuminating Company, an Ohio electric utility operating subsidiary
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
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 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
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
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

GLOSSARY OF TERMS, Continued

ASLB	Atomic Safety and Licensing Board
ASU	Accounting Standards Update
BGS	Basic Generation Service
BRA	PJM RPM Base Residual Auction
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CBA	Collective Bargaining Agreement
CCB	Coal Combustion By-products
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
CO_2	Carbon Dioxide
CSA	Coal Sales Agreement
CSAPR	Cross-State Air Pollution Rule
CTA	Consolidated Tax Adjustment
CWA	Clean Water Act
CWIP	Construction Work in Progress
DCR	Delivery Capital Recovery
DOE	United States Department of Energy
DOL	United States Department of Labor
DR	Demand Response
DSP	Default Service Plan
EDC	Electric Distribution Company
EE&C	Energy Efficiency and Conservation
EGS	Electric Generation Supplier
ELPC	Environmental Law & Policy Center
ENEC	Expanded Net Energy Cost
EPA	United States Environmental Protection Agency
ERO	Electric Reliability Organization
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
IBEW	International Brotherhood of Electrical Workers
ICE	IntercontinentalExchange, Inc.
ICG	International Coal Group Inc.
IRS	Internal Revenue Service
kV	Kilovolt

KWH	Kilowatt-hour
LBR	Little Blue Run
LCAPP	Long-Term Capacity Agreement Pilot Program
LMP	Locational Marginal Price

GLOSSARY OF TERMS, Continued

LOC	Letter of Credit
LSE	Load Serving Entity
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.
MOPR	Minimum Offer Price Rule
MVP	Multi-Value Project
MW	Megawatt
MWH	Megawatt-hour
NDT	Nuclear Decommissioning Trust
NERC	North American Electric Reliability Corporation
NITS	Network Integration Transmission Service
NJBPU	New Jersey Board of Public Utilities
NMB	Non-Market Based
NNSR	Non-Attainment New Source Review
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, Inc.
NYPSC	New York State Public Service Commission
OATT	Open Access Transmission Tariff
OCC	Ohio Consumers' Counsel
OPEB	Other Post-Employment Benefits
OTTI	Other Than Temporary Impairments
OVEC	Ohio Valley Electric Corporation
PA DEP	Pennsylvania Department of Environmental Protection
PCRB	Pollution Control Revenue Bond
PJM	PJM Interconnection, L.L.C.
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
RCRA	Resource Conservation and Recovery Act
REC	Renewable Energy Credit
REIT	Real Estate Investment Trust

RFC	ReliabilityFirst Corporation
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must-Run

GLOSSARY OF TERMS, Continued

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
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
TMDL	Total Maximum Daily Load
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. FINANCIAL INFORMATION

ITEM I. Financial Statements

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
(In millions, except per share amounts)	2014	2013	2014	2013
REVENUES:				
Electric utilities	$2,554	$2,526	$7,542	$7,128
Unregulated businesses	1,334	1,506	4,024	4,131
Total revenues*	3,888	4,032	11,566	11,259
OPERATING EXPENSES:				
Fuel	544	657	1,711	1,915
Purchased power	1,188	1,120	3,726	2,932
Other operating expenses	858	877	3,061	2,645
Provision for depreciation	308	316	904	909
Amortization of regulatory assets, net	35	312	27	443
General taxes	239	242	738	747
Impairment of long-lived assets	—	—	—	473
Total operating expenses	3,172	3,524	10,167	10,064
OPERATING INCOME	716	508	1,399	1,195
OTHER INCOME (EXPENSE):				
Gain (loss) on debt redemptions (Note 8)	—	9	(8)	(132)
Investment income	16	5	67	8
Interest expense	(275)	(257)	(802)	(771)
Capitalized financing costs	28	21	89	62
Total other expense	(231)	(222)	(654)	(833)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	485	286	745	362
INCOME TAXES	152	77	226	129
INCOME FROM CONTINUING OPERATIONS	333	209	519	233
Discontinued operations (net of income taxes of $0, $3, $69 and $9, respectively) (Note 14)	—	9	86	17
NET INCOME	$333	$218	$605	$250
EARNINGS PER SHARE OF COMMON STOCK:				

Basic - Continuing Operations	$0.79	$0.50	$1.24	$0.56
Basic - Discontinued Operations (Note 14)	—	0.02	0.20	0.04
Basic - Net Earnings per Basic Share	$0.79	$0.52	$1.44	$0.60
Diluted - Continuing Operations	$0.79	$0.50	$1.24	$0.56
Diluted - Discontinued Operations (Note 14)	—	0.02	0.20	0.04
Diluted - Net Earnings per Diluted Share	$0.79	$0.52	$1.44	$0.60
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING:				
Basic	420	418	419	418
Diluted	421	419	420	419
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK**	$0.72	$1.10	$1.44	$1.65

* Includes excise tax collections of $105 million and $117 million in the three months ended September 30, 2014 and 2013, respectively, and $321 million and $346 million in the nine months ended September 30, 2014 and 2013, respectively.

** The nine months ended September 30, 2014 includes a dividend declared of $0.36 per share on each of January 21, 2014; March 18, 2014; July 15, 2014; and September 16, 2014 paid or payable on March 1, 2014; June 1 2014; September 1, 2014; and December 1, 2014, respectively. The nine months ended September 30, 2013 includes a dividend declared of $0.55 per share on each of March 19, 2013; July 16, 2013; and September 17, 2013 paid on June 1, 2013; September 1, 2013; and December 1, 2013, respectively.

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

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FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
(In millions)	2014	2013	2014	2013
NET INCOME	$333	$218	$605	$250
OTHER COMPREHENSIVE INCOME (LOSS):				
Pensions and OPEB prior service costs	(42)	(47)	(126)	(148)
Amortized gains (losses) on derivative hedges	—	2	(1)	4
Change in unrealized gain on available-for-sale securities	(11)	6	40	3
Other comprehensive loss	(53)	(39)	(87)	(141)
Income tax benefits on other comprehensive loss	(21)	(15)	(35)	(55)
Other comprehensive loss, net of tax	(32)	(24)	(52)	(86)
COMPREHENSIVE INCOME	$301	$194	$553	$164

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

FIRSTENERGY CORP.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions, except share amounts)	September 30, 2014	December 31, 2013
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$109	$218
Receivables-		
Customers, net of allowance for uncollectible accounts of $63 in 2014 and $52 in 2013	1,605	1,720
Other, net of allowance for uncollectible accounts of $5 in 2014 and $3 in 2013	214	198
Materials and supplies, at average cost	771	752
Prepaid taxes	185	226
Derivatives	180	166
Accumulated deferred income taxes	327	366
Collateral	221	155
Other	173	212
	3,785	4,013
PROPERTY, PLANT AND EQUIPMENT:		
In service	46,664	44,228
Less — Accumulated provision for depreciation	14,040	13,280
	32,624	30,948
Construction work in progress	2,301	2,304
	34,925	33,252
INVESTMENTS:		
Nuclear plant decommissioning trusts	2,365	2,201
Other	894	903
	3,259	3,104
ASSETS HELD FOR SALE	—	235
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	6,418	6,418
Regulatory assets	1,668	1,854
Other	1,169	1,548
	9,255	9,820
	$51,224	$50,424
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$1,386	$1,415
Short-term borrowings	1,621	3,404
Accounts payable	1,190	1,250
Accrued taxes	489	485
Accrued compensation and benefits	277	351
Derivatives	166	111
Other	850	621
	5,979	7,637
CAPITALIZATION:		

Common stockholders' equity-		
Common stock, $0.10 par value, authorized 490,000,000 shares - 420,729,105 and 418,628,559 shares outstanding as of September 30, 2014 and December 31, 2013, respectively	42	42
Other paid-in capital	9,836	9,776
Accumulated other comprehensive income	232	284
Retained earnings	2,592	2,590
Total common stockholders' equity	12,702	12,692
Noncontrolling interest	2	3
Total equity	12,704	12,695
Long-term debt and other long-term obligations	18,531	15,831
	31,235	28,526
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	7,188	6,968
Retirement benefits	2,754	2,689
Asset retirement obligations	1,755	1,678
Deferred gain on sale and leaseback transaction	833	858
Adverse power contract liability	222	290
Other	1,258	1,778
	14,010	14,261
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 11)		
	$51,224	$50,424

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30	
(In millions)	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$605	$250
Adjustments to reconcile net income to net cash from operating activities-		
Income from discontinued operations (Note 14)	(86)	(17)
Provision for depreciation	904	909
Amortization of regulatory assets, net	27	443
Nuclear fuel amortization	160	156
Deferred purchased power and other costs	(89)	(61)
Deferred income taxes and investment tax credits, net	327	114
Impairments of long-lived assets	—	473
Investment impairments	10	74
Deferred rents and lease market valuation liability	(56)	(48)
Retirement benefits	(60)	(133)
Gain on asset sales	—	(21)
Commodity derivative transactions, net (Note 9)	60	15
Loss on debt redemptions (Note 8)	8	132
Make-whole premiums paid on debt redemptions	—	(181)
Changes in current assets and liabilities-		
Receivables	90	(7)
Materials and supplies	(19)	117
Prepayments and other current assets	42	(59)
Accounts payable	(47)	(279)
Accrued taxes	(145)	(146)
Accrued interest	66	29
Accrued compensation and benefits	(74)	(43)
Cash collateral, net	(71)	(67)
Other	85	21
Net cash provided from operating activities	1,737	1,671
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Long-term debt	3,778	2,745
Short-term borrowings, net	—	1,435
Redemptions and Repayments-		
Long-term debt	(1,062)	(2,662)
Short-term borrowings, net	(1,783)	—
Tender premiums paid on debt redemptions	—	(110)
Common stock dividend payments	(452)	(690)
Other	(37)	(64)
Net cash provided from financing activities	444	654
CASH FLOWS FROM INVESTING ACTIVITIES:		

Property additions	(2,473)	(1,960)
Nuclear fuel	(98)	(159)
Proceeds from asset sales	394	—
Sales of investment securities held in trusts	1,511	1,545
Purchases of investment securities held in trusts	(1,593)	(1,567)
Cash investments	42	(12)
Asset removal costs	(80)	(125)
Other	7	3
Net cash used for investing activities	(2,290)	(2,275)
Net change in cash and cash equivalents	(109)	50
Cash and cash equivalents at beginning of period	218	172
Cash and cash equivalents at end of period	$109	$222

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

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)
(Unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
(In millions)	2014	2013	2014	2013
STATEMENTS OF INCOME (LOSS)				
REVENUES:				
Electric sales to non-affiliates	$1,315	$1,455	$3,989	$4,066
Electric sales to affiliates	164	186	689	482
Other	42	38	124	107
Total revenues	1,521	1,679	4,802	4,655
OPERATING EXPENSES:				
Fuel	270	304	923	936
Purchased power from affiliates	64	132	203	401
Purchased power from non-affiliates	627	724	2,274	1,755
Other operating expenses	356	339	1,276	1,105
Provision for depreciation	83	80	236	231
General taxes	31	35	99	106
Total operating expenses	1,431	1,614	5,011	4,534
OPERATING INCOME (LOSS)	90	65	(209)	121
OTHER INCOME (EXPENSE):				
Loss on debt redemptions (Note 8)	(1)	—	(6)	(103)
Investment income (loss)	13	(3)	57	(4)
Miscellaneous income	1	21	5	29
Interest expense — affiliates	(1)	(1)	(5)	(7)
Interest expense — other	(37)	(35)	(110)	(126)
Capitalized interest	7	9	27	28
Total other expense	(18)	(9)	(32)	(183)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES (BENEFITS)	72	56	(241)	(62)
INCOME TAXES (BENEFITS)	28	23	(95)	(19)
INCOME (LOSS) FROM CONTINUING OPERATIONS	44	33	(146)	(43)
Discontinued operations (net of income taxes of $0, $5, $70 and $8, respectively) (Note 14)	—	7	116	14
NET INCOME (LOSS)	$44	$40	$(30)	$(29)

STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

NET INCOME (LOSS)	$44	$40	$(30)	$(29)
OTHER COMPREHENSIVE INCOME (LOSS):				
Pensions and OPEB prior service costs	(4)	(5)	(14)	(16)
Amortized gain on derivative hedges	(2)	(1)	(7)	(3)
Change in unrealized gain on available-for-sale securities	(9)	5	35	2
Other comprehensive income (loss)	(15)	(1)	14	(17)
Income taxes (benefits) on other comprehensive income (loss)	(6)	(1)	5	(7)
Other comprehensive income (loss), net of tax	(9)	—	9	(10)
COMPREHENSIVE INCOME (LOSS)	$35	$40	$(21)	$(39)

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

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions, except share amounts)	September 30, 2014	December 31, 2013
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$2	$2
Receivables-		
Customers, net of allowance for uncollectible accounts of $21 in 2014 and $11 in 2013	445	539
Affiliated companies	488	1,036
Other, net of allowance for uncollectible accounts of $3 in 2014 and 2013	114	81
Notes receivable from affiliated companies	214	—
Materials and supplies	471	448
Derivatives	168	165
Collateral	218	136
Prepayments and other	98	109
	2,218	2,516
PROPERTY, PLANT AND EQUIPMENT:		
In service	13,745	12,472
Less — Accumulated provision for depreciation	5,087	4,755
	8,658	7,717
Construction work in progress	688	1,308
	9,346	9,025
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,381	1,276
Other	11	11
	1,392	1,287
ASSETS HELD FOR SALE	—	122
DEFERRED CHARGES AND OTHER ASSETS:		
Customer intangibles	82	95
Goodwill	23	23
Property taxes	9	41
Unamortized sale and leaseback costs	210	168
Derivatives	42	53
Other	107	172
	473	552
	$13,429	$13,502
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$535	$892
Short-term borrowings-		
Affiliated companies	—	431
Other	21	4
Accounts payable-		
Affiliated companies	453	765

Other	178	290
Accrued taxes	167	66
Derivatives	166	110
Other	170	197
	1,690	2,755
CAPITALIZATION:		
Common stockholder's equity-		
Common stock, without par value, authorized 750 shares - 7 shares outstanding as of September 30, 2014 and December 31, 2013	3,592	3,080
Accumulated other comprehensive income	63	54
Retained earnings	2,148	2,178
Total common stockholder's equity	5,803	5,312
Long-term debt and other long-term obligations	2,631	2,130
	8,434	7,442
NONCURRENT LIABILITIES:		
Deferred gain on sale and leaseback transaction	833	858
Accumulated deferred income taxes	741	741
Retirement benefits	197	185
Asset retirement obligations	1,059	1,015
Derivatives	20	14
Other	455	492
	3,305	3,305
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 11)		
	$13,429	$13,502

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

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

	Nine Months Ended September 30	
(In millions)	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$(30)	$(29)
Adjustments to reconcile net loss to net cash from operating activities-		
Income from discontinued operations (Note 14)	(116)	(14)
Provision for depreciation	236	231
Nuclear fuel amortization	160	156
Deferred rents and lease market valuation liability	(63)	(61)
Deferred income taxes and investment tax credits, net	(15)	205
Investment impairments	9	66
Gain on asset sales	—	(20)
Commodity derivative transactions, net (Note 9)	61	15
Loss on debt redemptions (Note 8)	6	103
Make-whole premiums paid on debt redemptions	—	(31)
Changes in current assets and liabilities-		
Receivables	609	(214)
Materials and supplies	(23)	66
Prepayments and other current assets	26	(22)
Accounts payable	(383)	129
Accrued taxes	7	(131)
Accrued compensation and benefits	(15)	(5)
Cash collateral, net	(82)	(35)
Other	41	(20)
Net cash provided from operating activities	428	389
CASH FLOWS FROM FINANCING ACTIVITIES:		
New financing-		
Long-term debt	878	—
Equity contribution from parent	500	1,500
Redemptions and repayments-		
Long-term debt	(749)	(1,179)
Short-term borrowings, net	(414)	—
Tender premiums paid on debt redemptions	—	(67)
Other	(14)	(7)
Net cash provided from financing activities	201	247
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(586)	(477)
Nuclear fuel	(98)	(159)
Proceeds from asset sales	307	21
Sales of investment securities held in trusts	890	650
Purchases of investment securities held in trusts	(933)	(694)

Loans to affiliated companies, net	(214)	22
Other	5	—
Net cash used for investing activities	(629)	(637)
Net change in cash and cash equivalents	—	(1)
Cash and cash equivalents at beginning of period	2	3
Cash and cash equivalents at end of period	$2	$2

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

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FIRSTENERGY CORP. AND SUBSIDIARIES

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

1. ORGANIZATION AND BASIS OF PRESENTATION

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

FirstEnergy Corp. was organized under the laws of the State of Ohio in 1996. FirstEnergy’s principal business is the holding, directly or indirectly, of all of the outstanding common stock of its principal subsidiaries: OE, CEI, TE, Penn (a wholly owned subsidiary of OE), JCP&L, ME, PN, FESC, FES and its principal subsidiaries (FG and NG), AE Supply, MP, PE, WP and FET and its principal subsidiaries ATSI and TrAIL. In addition, FirstEnergy holds all of the outstanding common stock of other direct subsidiaries including: FirstEnergy Properties, Inc., FEV, FENOC, FELHC, Inc., and GPU Nuclear, Inc.

These interim financial statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and disclosures normally included in financial statements and notes prepared in accordance with GAAP have been condensed or omitted pursuant to such rules and regulations. These interim financial statements should be read in conjunction with the financial statements and notes included in the combined Annual Report on Form 10-K for the year ended December 31, 2013.

FirstEnergy follows GAAP and complies with the related regulations, orders, policies and practices prescribed by the SEC, FERC, and, as applicable, the PUCO, the PPUC, the MDPSC, the NYPSC, the WVPSC, the VSCC and the NJBPU. The accompanying interim financial statements are unaudited, but reflect all adjustments, consisting of normal recurring adjustments, that, in the opinion of management, are necessary for a fair statement of the financial statements. The preparation of financial statements in conformity with GAAP requires management to make periodic estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and disclosure of contingent assets and liabilities. Actual results could differ from these estimates. The reported results of operations are not indicative of results of operations for any future period. FE and its subsidiaries have evaluated events and transactions for potential recognition or disclosure through the date the financial statements were issued.

FE and its subsidiaries consolidate all majority-owned subsidiaries over which they exercise control and, when applicable, entities for which they have a controlling financial interest. Intercompany transactions and balances are eliminated in consolidation. FE and its subsidiaries consolidate a VIE when it is determined that it is the primary beneficiary (see Note 7, Variable Interest Entities). Investments in affiliates over which FE and its subsidiaries have the ability to exercise significant influence, but with respect to which they are not the primary beneficiary and do not exercise control, follow the equity method of accounting. Under the equity method, the interest in the entity is reported as an investment in the Consolidated Balance Sheets and the percentage share of the entity’s earnings is reported in the Consolidated Statements of Income and Comprehensive Income. These Notes to the Consolidated Financial Statements are combined for FirstEnergy and FES.

For the three months ended September 30, 2014 and 2013, capitalized financing costs on FirstEnergy's Consolidated Statements of Income includes $14 million and $4 million, respectively, of allowance for equity funds used during construction and $14 million and $17 million, respectively, of capitalized interest. For the nine months ended September 30, 2014 and 2013, capitalized financing costs on FirstEnergy's Consolidated Statements of Income includes $35 million and $11 million, respectively, of allowance for equity funds used during construction, and $54 million and $51 million, respectively, of capitalized interest.

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

New Accounting Pronouncements

In May 2014, the FASB issued ASU No. 2014-09, 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, ASU No. 2014-09 specifies the accounting for costs to obtain or fulfill a contract with a customer and expands disclosure requirements for revenue recognition. 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.

2. 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.

FirstEnergy’s reporting units are consistent with its reportable segments and consist of Regulated Distribution, Regulated Transmission, Competitive Energy Services and Other/Corporate. The following table presents goodwill by reporting unit (there have been no changes in goodwill for any reporting unit during 2014):

Goodwill	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other/Corporate	Consolidated
	(In millions)				
Balance as of September 30, 2014	$5,092	$526	$800	$ —	$6,418

FirstEnergy performed a quantitative assessment for the Regulated Distribution, Regulated Transmission and Competitive Energy Services 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 Competitive Energy Services 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 Competitive Energy Services 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 and other environmental legislation, 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.

3. EARNINGS PER SHARE OF COMMON STOCK

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

The following table reconciles basic and diluted earnings per share of common stock:

(In millions, except per share amounts)	Three Months Ended September 30		Nine Months Ended September 30	
Reconciliation of Basic and Diluted Earnings per Share of Common Stock	2014	2013	2014	2013
Income from continuing operations	$333	$209	$519	$233
Discontinued operations (Note 14)	—	9	86	17
Net income	$333	$218	$605	$250
Weighted average number of basic shares outstanding	420	418	419	418
Assumed exercise of dilutive stock options and awards[(1)]	1	1	1	1
Weighted average number of diluted shares outstanding	421	419	420	419
Earnings per share:				
Basic earnings per share:				
Income from continuing operations	$0.79	$0.50	$1.24	$0.56
Discontinued operations (Note 14)	—	0.02	0.20	0.04
Net earnings per basic share	$0.79	$0.52	$1.44	$0.60
Diluted earnings per share:				
Income from continuing operations	$0.79	$0.50	$1.24	$0.56
Discontinued operations (Note 14)	—	0.02	0.20	0.04
Net earnings per diluted share	$0.79	$0.52	$1.44	$0.60

(1) For the three months ended September 30, 2014 and September 30, 2013, 1 million and 2 million shares, respectively, were excluded from the calculation of diluted shares outstanding, as their inclusion would be antidilutive. For the nine months ended September 30, 2014 and September 30, 2013, 2 million shares were excluded from the calculation of diluted shares outstanding, as their inclusion would be antidilutive.

4. PENSIONS AND OTHER POSTEMPLOYMENT BENEFITS

On August 25, 2014, the qualified pension plan was amended authorizing a voluntary cashout window program for certain eligible terminated participants with vested benefits. Eligible terminated participants will be able to elect an immediate lump sum cash payment of their vested benefits. Additionally, annuity options will also be offered and may be elected instead of the lump sum cash payment. The election period is September 15, 2014 to October 31, 2014. Payment of benefits for participants that elect an immediate lump sum cash payment or an annuity will commence on December 1, 2014. The components of the consolidated net periodic cost (credits) for pensions and OPEB (including amounts capitalized) were as follows:

Components of Net Periodic Benefit Costs (Credits)	Pensions		OPEB	
For the Three Months Ended September 30,	2014	2013	2014	2013
	(In millions)			
Service costs	$42	$49	$2	$3
Interest costs	100	93	9	9
Expected return on plan assets	(116)	(125)	(8)	(8)
Amortization of prior service costs (credits)	2	3	(44)	(50)
Net periodic costs (credits)	$28	$20	$(41)	$(46)

Components of Net Periodic Benefit Costs (Credits)	Pensions		OPEB	
For the Nine Months Ended September 30,	2014	2013	2014	2013
	(In millions)			
Service costs	$125	$147	$6	$9
Interest costs	301	279	29	27
Expected return on plan assets	(346)	(375)	(24)	(24)
Amortization of prior service costs (credits)	6	9	(132)	(157)
Net periodic costs (credits)	$86	$60	$(121)	$(145)

FES' share of the net periodic pensions and OPEB costs (credits) were as follows:

	Pensions		OPEB	
	2014	2013	2014	2013
	(In millions)			
For the Three Months Ended September 30,	$5	$5	$(5)	$(5)
For the Nine Months Ended September 30,	$13	$15	$(15)	$(15)

Pension and OPEB obligations are allocated to FE's subsidiaries, including FES, employing the plan participants. The net periodic pension and OPEB costs (credits) (net of amounts capitalized) recognized in earnings by FE and FES were as follows:

Net Periodic Benefit Expense (Credit)	Pensions		OPEB	
For the Three Months Ended September 30,	2014	2013	2014	2013
	(In millions)			
FirstEnergy	$19	$16	$(24)	$(31)
FES	4	5	(4)	(4)

Net Periodic Benefit Expense (Credit)	Pensions		OPEB	
For the Nine Months Ended September 30,	2014	2013	2014	2013
	(In millions)			
FirstEnergy	$61	$41	$(78)	$(95)

FES	12	13	(13)	(12)
12				

5. ACCUMULATED OTHER COMPREHENSIVE INCOME

The changes in AOCI, net of tax, in the three and nine months ended September 30, 2014 and 2013, for FirstEnergy and FES are shown in the following tables:

FirstEnergy

	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
	(In millions)			
AOCI Balance as of July 1, 2014	$(36)	$41	$259	$264
Other comprehensive income before reclassifications	—	2	—	2
Amounts reclassified from AOCI	—	(8)	(26)	(34)
Net other comprehensive loss	—	(6)	(26)	(32)
AOCI Balance as of September 30, 2014	$(36)	$35	$233	$232
AOCI Balance as of July 1, 2013	$(37)	$13	$347	$323
Other comprehensive income before reclassifications[1]	—	5	—	5
Amounts reclassified from AOCI	1	(1)	(29)	(29)
Net other comprehensive income (loss)	1	4	(29)	(24)
AOCI Balance as of September 30, 2013	$(36)	$17	$318	$299

[1] Unrealized Gains on AFS Securities is net of tax of $3 million.

FES

	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
	(In millions)			
AOCI Balance as of July 1, 2014	$(5)	$36	$41	$72
Other comprehensive income before reclassifications[1]	—	1	—	1
Amounts reclassified from AOCI	(1)	(6)	(3)	(10)
Net other comprehensive loss	(1)	(5)	(3)	(9)
AOCI Balance as of September 30, 2014	$(6)	$31	$38	$63
AOCI Balance as of July 1, 2013	$1	$12	$49	$62
Other comprehensive income before reclassifications[2]	—	4	—	4

Amounts reclassified from AOCI	—	(1)	(3)	(4)
Net other comprehensive income (loss)	—	3	(3)	—
AOCI Balance as of September 30, 2013	$1	$15	$46	$62

[1] Unrealized Gains on AFS Securities is net of tax of $1 million.
[2] Unrealized Gains on AFS Securities is net of tax of $3 million.

FirstEnergy

	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
	(In millions)			
AOCI Balance as of January 1, 2014	$(36)	$9	$311	$284
Other comprehensive income before reclassifications(1)	1	55	—	56
Amounts reclassified from AOCI	(1)	(29)	(78)	(108)
Net other comprehensive income (loss)	—	26	(78)	(52)
AOCI Balance as of September 30, 2014	$(36)	$35	$233	$232
AOCI Balance as of January 1, 2013	$(38)	$15	$408	$385
Other comprehensive income before reclassifications(2)	—	19	—	19
Amounts reclassified from AOCI	2	(17)	(90)	(105)
Net other comprehensive income (loss)	2	2	(90)	(86)
AOCI Balance as of September 30, 2013	$(36)	$17	$318	$299

(1) Unrealized Gains on AFS Securities is net of tax of $30 million.
(2) Unrealized Gains on AFS Securities is net of tax of $11 million.

FES

	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
	(In millions)			
AOCI Balance as of January 1, 2014	$(1)	$8	$47	$54
Other comprehensive income (loss) before reclassifications(1)	(1)	50	—	49
Amounts reclassified from AOCI	(4)	(27)	(9)	(40)
Net other comprehensive income (loss)	(5)	23	(9)	9
AOCI Balance as of September 30, 2014	$(6)	$31	$38	$63
AOCI Balance as of January 1, 2013	$3	$13	$56	$72
Other comprehensive income before reclassifications(2)	—	17	—	17
Amounts reclassified from AOCI	(2)	(15)	(10)	(27)
Net other comprehensive income (loss)	(2)	2	(10)	(10)

AOCI Balance as of September 30, 2013	$1	$15	$46	$62

(1) Unrealized Gains on AFS Securities is net of tax of $29 million.
(2) Unrealized Gains on AFS Securities is net of tax of $9 million.

The following amounts were reclassified from AOCI in the three months ended September 30, 2014 and 2013:

FE	Three Months Ended September 30		Nine Months Ended September 30		Affected Line Item in Consolidated Statements of
Reclassifications from AOCI [2]	2014	2013	2014	2013	Income
	(In millions)				
Gains & losses on cash flow hedges					
Commodity contracts	$(2)	$(1)	$(7)	$(5)	Other operating expenses
Long-term debt	2	3	6	9	Interest expense
	—	2	(1)	4	Total before taxes
	—	(1)	—	(2)	Income taxes
	$—	$1	$(1)	$2	Net of tax
Unrealized gains on AFS securities					
Realized gains on sales of securities	$(13)	$(2)	$(46)	$(27)	Investment income
	5	1	17	10	Income taxes
	$(8)	$(1)	$(29)	$(17)	Net of tax
Defined benefit pension and OPEB plans					
Prior-service costs	$(42)	$(47)	$(126)	$(148)	[1]
	16	18	48	58	Income taxes
	$(26)	$(29)	$(78)	$(90)	Net of tax

[1] These AOCI components are included in the computation of net periodic pension cost. See Note 4, Pensions and Other Postemployment Benefits for additional details.
[2] Parenthesis represent credits to the Consolidated Statements of Income from AOCI.

FES	Three Months Ended September 30		Nine Months Ended September 30		Affected Line Item in Consolidated Statements of
Reclassifications from AOCI [2]	2014	2013	2014	2013	Income (Loss)
	(In millions)				
Gains & losses on cash flow hedges					
Commodity contracts	$(2)	$(1)	$(7)	$(5)	Other operating expenses
Long-term debt	—	—	—	2	Interest expense — other
	(2)	(1)	(7)	(3)	Total before taxes
	1	1	3	1	Income taxes (benefits)
	$(1)	$—	$(4)	$(2)	Net of tax
Unrealized gains on AFS securities					
Realized gains on sales of securities	$(11)	$(2)	$(43)	$(24)	Investment income (loss)
	5	1	16	9	Income taxes (benefits)
	$(6)	$(1)	$(27)	$(15)	Net of tax
Defined benefit pension and OPEB plans					
Prior-service costs	$(4)	$(5)	$(14)	$(16)	[1]
	1	2	5	6	Income taxes (benefits)
	$(3)	$(3)	$(9)	$(10)	Net of tax

(1) These AOCI components are included in the computation of net periodic pension cost. See Note 4, Pensions and Other Postemployment Benefits for additional details.
(2) Parenthesis represent credits to the Consolidated Statements of Income (Loss) from AOCI.

6. INCOME TAXES

FirstEnergy’s and FES’ interim effective tax rates reflect the estimated annual effective tax rates for 2014 and 2013, adjusted for tax expense associated with certain discrete items that may occur in any given period, but are not consistent from period to period.

FirstEnergy’s effective tax rate from continuing operations for the three months ended September 30, 2014 and 2013 was 31.3% and 26.9%, respectively. The 2014 effective tax rate was impacted primarily from an IRS-approved change in accounting method for costs associated with the refurbishment of meters and transformers, partially offset by a valuation allowance against local NOL carryforwards. The accounting method change resulted in an increase in the tax basis of certain assets for costs previously not deducted for tax purposes. 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's effective tax rates from continuing operations for the nine months ended September 30, 2014 and 2013 were 30.3% and 35.6%, respectively. The decrease in the effective tax rate is primarily due to a change in accounting method as described above, the elimination of certain future tax liabilities associated with basis differences, a reduction in state deferred tax liabilities resulting from changes in state apportionment factors, and a reduction in the amount of valuation allowance against state and local NOL carryforwards recorded year over year.

FES’ effective tax rates from continuing operations for the three months ended September 30, 2014 and 2013 were 38.9% and 41.1%, respectively. The decrease in the effective tax rate is primarily due to an increase in pre-tax losses from continuing operations in jurisdictions with higher tax rates, partially offset by valuation allowances on local NOL carryforwards. The effective tax rates for the nine months ended September 30, 2014 and 2013 were 39.4% and 30.6%, respectively. The increase in the effective tax rate on losses from continuing operations is primarily due to an increase in pre-tax losses from continuing operations in jurisdictions with higher tax rates, a benefit resulting from a reduction in state deferred tax liabilities associated with changes in apportionment factors, partially offset by valuation allowances against local NOL carryforwards.

On October 15, 2014, approximately $30 million of previously unrecognized income tax benefits including interest, related to positions taken in determining business nexus, were recognized as a result of the statute of limitations expiring, all of which will affect FirstEnergy's effective tax rate in the fourth quarter of 2014.

In April 2014, the IRS completed its examination of FirstEnergy’s 2011 and 2012 federal income tax returns and issued Revenue Agent Reports for those years, which did not result in a material impact to FirstEnergy’s effective tax rate.

7. VARIABLE INTEREST ENTITIES

FirstEnergy performs qualitative analyses to determine whether a variable interest gives FirstEnergy a controlling financial interest in a VIE. This analysis identifies the primary beneficiary of a VIE as the enterprise that has both the power to direct the activities of a VIE that most significantly impact the entity’s economic performance and the obligation to absorb losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE. FirstEnergy consolidates a VIE when it is determined that it is the primary beneficiary.

VIEs included in FirstEnergy’s consolidated financial statements are: the PNBV capital trusts that were created to refinance debt originally issued in connection with sale and leaseback transactions; wholly-owned limited liability companies of the Ohio Companies (as described below); wholly owned limited liability companies of JCP&L created to sell transition bonds to securitize the recovery of JCP&L’s bondable stranded costs and special purpose limited liability companies created to issue environmental control bonds that were used to construct environmental control facilities.

The caption "noncontrolling interest" within the consolidated financial statements is used to reflect the portion of a VIE that FirstEnergy consolidates, but does not own. The change in noncontrolling interest within the Consolidated Balance Sheets during the nine months ended September 30, 2014, was primarily due to a distribution to owners.

In order to evaluate contracts for consolidation treatment and entities for which FirstEnergy has an interest, FirstEnergy aggregates variable interests into the following categories based on similar risk characteristics and significance.

Ohio Securitization

In September 2012, the Ohio Companies formed CEI Funding LLC, OE Funding LLC and TE Funding LLC, respectively, as separate, wholly-owned limited liability SPEs. The phase-in recovery bonds issued by these SPEs are payable only from, and secured by, phase-in recovery property held by the SPEs (i.e. the right to impose, charge and collect irrevocable non-bypassable usage-based charges payable by retail electric customers in the service territories of the Ohio Companies) and the bondholder has no recourse to the general credit of FirstEnergy or any of the Ohio Companies. The SPEs are considered VIEs and each one is consolidated into its applicable utility.

Mining Operations

FEV holds a 33-1/3% equity ownership in Global Holding, the holding company for a joint venture in the Signal Peak mining and coal transportation operations. FEV is not the primary beneficiary of the joint venture, as it does not have control over the significant activities affecting the joint venture's economic performance. FEV's ownership interest is subject to the equity method of accounting.

Trusts

FirstEnergy's consolidated financial statements include PNBV. FirstEnergy used debt and available funds to purchase the notes issued by PNBV for the purchase of lease obligation bonds. Ownership of PNBV includes a 3% equity interest by an unaffiliated third party and a 3% equity interest held by OES Ventures, a wholly owned subsidiary of OE.

PATH-WV

PATH is a series limited liability company that is comprised of multiple series, each of which has separate rights, powers and duties regarding specified property and the series profits and losses associated with such property. A subsidiary of FirstEnergy owns 100% of the Allegheny Series (PATH-Allegheny) and 50% of the West Virginia Series (PATH-WV), which is a joint venture with a subsidiary of AEP. FirstEnergy is not the primary beneficiary of PATH-WV, as it does not have control over the significant activities affecting the economics of the portion of the PATH project that was to be constructed by PATH-WV.

On August 24, 2012, PJM removed the PATH project from its long-range expansion plans. See Note 10, Regulatory Matters, for additional information on the abandonment of PATH.

Power Purchase Agreements

FirstEnergy evaluated its power purchase agreements and determined that certain NUG entities at its Regulated Distribution segment may be VIEs to the extent that they own a plant that sells substantially all of its output to the applicable utilities and the contract price for power is correlated with the plant's variable costs of production. FirstEnergy maintains 18 long-term power purchase agreements with NUG entities that were entered into pursuant to PURPA. FirstEnergy was not involved in the creation of, and has no equity or debt invested in, any of these entities.

FirstEnergy has determined that for all but two of these NUG entities, it does not have variable interests in the entities or the entities do not meet the criteria to be considered a VIE. FirstEnergy may hold variable interests in the remaining two entities; however, it applied the scope exception that exempts enterprises unable to obtain the necessary information to evaluate entities.

Because FirstEnergy has no equity or debt interests in the NUG entities, its maximum exposure to loss relates primarily to the above-market costs incurred for power. FirstEnergy expects any above-market costs incurred at its Regulated Distribution segment to be recovered from customers. Purchased power costs related to the contracts that may contain a variable interest were $49 million and $48 million during the three months ended September 30, 2014 and 2013, respectively, and $150 million and $139 million during the nine months ended September 30, 2014 and 2013, respectively.

Sale and Leaseback

FirstEnergy has variable interests in certain sale and leaseback transactions. FirstEnergy is not the primary beneficiary of these interests as it does not have control over the significant activities affecting the economics of the arrangements.

In March of 2013, FG acquired the remaining interests in connection with the 1987 Bruce Mansfield Plant sale and leaseback transactions for approximately $221 million. Also during 2013, NG purchased lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for $23 million.

In February 2014, NG purchased lessor equity interests in OE's existing sale and leaseback of Beaver Valley Unit 2 for approximately $94 million. As of September 30, 2014, FirstEnergy's leasehold interest was 8.11% 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 representing approximately half 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. Finally, NG has recently reached an agreement in principle with the owner participants regarding its acquisition of the remaining lessor equity interests in OE's existing sale and leaseback of Perry Unit 1. However, no assurance can be given that an agreement will be finalized and the acquisition of the remaining Perry Unit 1 lessor equity interests will be completed.

FES, and other FE subsidiaries are exposed to losses under their applicable sale and leaseback agreements upon the occurrence of certain contingent events. The maximum exposure under these provisions represents the net amount of casualty value payments due upon the occurrence of specified casualty events. Net discounted lease payments would not be payable if the casualty loss payments were made. The following table discloses each company’s net exposure to loss based upon the casualty value provisions as of September 30, 2014:

	Maximum Exposure	Discounted Lease Payments, net[1]	Net Exposure
	(In millions)		
FES	$1,231	$1,017	$214
Other FE subsidiaries	670	399	271

[1]The net present value of FirstEnergy’s consolidated sale and leaseback operating lease commitments is $1.0 billion.

8. FAIR VALUE MEASUREMENTS

RECURRING AND NONRECURRING FAIR VALUE MEASUREMENTS

Authoritative accounting guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. This hierarchy gives the highest priority to Level 1 measurements and the lowest priority to Level 3 measurements. The three levels of the fair value hierarchy and a description of the valuation techniques are as follows:

Level 1 - Quoted prices for identical instruments in active market

Level 2 - Quoted prices for similar instruments in active market
- Quoted prices for identical or similar instruments in markets that are not active
- Model-derived valuations for which all significant inputs are observable market data

Models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures.

Level 3 - Valuation inputs are unobservable and significant to the fair value measurement

FirstEnergy produces a long-term power and capacity price forecast annually with periodic updates as market conditions change. When underlying prices are not observable, prices from the long-term price forecast, which has been reviewed and approved by FirstEnergy's Risk Policy Committee, are used to measure fair value. A more detailed description of FirstEnergy's valuation process for FTRs and NUGs are as follows:

FTRs are financial instruments that entitle the holder to a stream of revenues (or charges) based on the hourly day-ahead congestion price differences across transmission paths. FTRs are acquired by FirstEnergy in the annual, monthly and long-term RTO auctions and are initially recorded using the auction clearing price less cost. After initial recognition, FTRs' carrying values are periodically adjusted to fair value using a mark-to-model methodology, which approximates market. The primary inputs into the model, which are generally less observable than objective sources, are the most recent RTO auction clearing prices and the FTRs' remaining hours. The model calculates the fair value by multiplying the most recent auction clearing price by the remaining FTR hours less the prorated FTR cost. Generally, significant increases or decreases in inputs in isolation could result in a higher or lower fair value measurement. See Note 9, Derivative Instruments, for additional information regarding FirstEnergy's FTRs.

NUG contracts represent purchase power agreements with third-party non-utility generators that are transacted to satisfy certain obligations under PURPA. NUG contract carrying values are recorded at fair value and adjusted periodically using a mark-to-model methodology, which approximates market. The primary unobservable inputs into the model are regional power prices and generation MWH. Pricing for the NUG contracts is a combination of market prices for the current year and next three years based on observable data and internal models using historical trends and market data for the remaining years under contract. The internal models use forecasted energy purchase prices as an input when prices are not defined by the contract. Forecasted market prices are based on ICE quotes and management assumptions. Generation MWH reflects data provided by contractual arrangements and historical trends. The model calculates the fair value by multiplying the prices by the generation MWH. Generally, significant increases or decreases in inputs in isolation could result in a higher or lower fair value measurement.

LCAPP contracts are financially settled agreements that allow eligible generators to receive payments from, or make payments to, JCP&L, pursuant to an annually calculated load-ratio share of the capacity produced by the generator based upon the annual forecasted peak demand as determined by PJM. LCAPP contracts are recorded at fair value. During the fourth quarter of 2013, all LCAPP contracts were terminated. See Note 9, Derivative Instruments for additional information.

FirstEnergy primarily applies the market approach for recurring fair value measurements using the best information available. Accordingly, FirstEnergy maximizes the use of observable inputs and minimizes the use of unobservable inputs. There were no changes in valuation methodologies used as of September 30, 2014, from those used as of December 31, 2013. The determination of the fair value measures takes into consideration various factors, including but not limited to, nonperformance risk, counterparty credit risk and the impact of credit enhancements (such as cash deposits, LOCs and priority interests). The impact of these forms of risk was not significant to the fair value measurements.

Transfers between levels are recognized at the end of the reporting period. There were no transfers between levels during the nine months ended September 30, 2014. The following tables set forth the recurring assets and liabilities that are accounted for at fair value by level within the fair value hierarchy:

FirstEnergy

Recurring Fair Value Measurements	September 30, 2014				December 31, 2013			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$1,230	$—	$1,230	$—	$1,365	$—	$1,365
Derivative assets - commodity contracts	1	187	—	188	7	208	—	215
Derivative assets - FTRs	—	—	35	35	—	—	4	4
Derivative assets - NUG contracts[1]	—	—	2	2	—	—	20	20
Equity securities[2]	711	—	—	711	317	—	—	317
Foreign government debt securities	—	79	—	79	—	109	—	109
U.S. government debt securities	—	172	—	172	—	165	—	165
U.S. state debt securities	—	244	—	244	—	228	—	228
Other[3]	70	236	—	306	187	255	—	442
Total assets	$782	$2,148	$37	$2,967	$511	$2,330	$24	$2,865
Liabilities								
Derivative liabilities - commodity contracts	$(18)	$(158)	$—	$(176)	$(13)	$(100)	$—	$(113)
Derivative liabilities - FTRs	—	—	(11)	(11)	—	—	(12)	(12)
Derivative liabilities - NUG contracts[1]	—	—	(157)	(157)	—	—	(222)	(222)
Total liabilities	$(18)	$(158)	$(168)	$(344)	$(13)	$(100)	$(234)	$(347)
Net assets (liabilities)[4]	$764	$1,990	$(131)	$2,623	$498	$2,230	$(210)	$2,518

(1) NUG contracts are subject to regulatory accounting treatment and do not impact earnings.
(2) NDT funds hold equity portfolios whose performance is benchmarked against the Alerian MLP Index or the Wells Fargo Hybrid and Preferred Securities REIT index.
(3) Primarily consists of short-term cash investments.
(4) Excludes $(45) million and $10 million as of September 30, 2014 and December 31, 2013, respectively, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

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Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG contracts, LCAPP contracts and FTRs that are classified as Level 3 in the fair value hierarchy for the periods ended September 30, 2014 and December 31, 2013:

	NUG Contracts[1]			LCAPP Contracts			FTRs		
	Derivative Assets	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net
	(In millions)								
January 1, 2013 Balance	$36	$(290)	$(254)	$—	$(144)	$(144)	$8	$(9)	$(1)
Unrealized gain (loss)	(8)	(17)	(25)	—	(22)	(22)	3	1	4
Purchases	—	—	—	—	—	—	6	(15)	(9)
Terminations[2]	—	—	—	—	166	166	—	—	—
Settlements	(8)	85	77	—	—	—	(13)	11	(2)
December 31, 2013 Balance	$20	$(222)	$(202)	$—	$—	$—	$4	$(12)	$(8)
Unrealized gain	2	15	17	—	—	—	33	7	40
Purchases	—	—	—	—	—	—	26	(18)	8
Settlements	(20)	50	30	—	—	—	(28)	12	(16)
September 30, 2014 Balance	$2	$(157)	$(155)	$—	$—	$—	$35	$(11)	$24

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

(2) See Note 9, Derivative Instruments

Level 3 Quantitative Information

The following table provides quantitative information for FTRs and NUG contracts that are classified as Level 3 in the fair value hierarchy for the period ended September 30, 2014:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$24	Model	RTO auction clearing prices	($4.60) to $17.70	$1.25	Dollars/MWH
NUG Contracts	$(155)	Model	Generation	500 to 4,979,000	872,000	MWH
			Electricity regional prices	$45.60 to $69.80	$52.30	Dollars/MWH

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FES

Recurring Fair Value Measurements	September 30, 2014				December 31, 2013			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$670	$—	$670	$—	$792	$—	$792
Derivative assets - commodity contracts	1	187	—	188	7	208	—	215
Derivative assets - FTRs	—	—	22	22	—	—	3	3
Equity securities[1]	468	—	—	468	207	—	—	207
Foreign government debt securities	—	57	—	57	—	65	—	65
U.S. government debt securities	—	37	—	37	—	27	—	27
U.S. state debt securities	—	7	—	7	—	—	—	—
Other[2]	—	178	—	178	—	176	—	176
Total assets	$469	$1,136	$22	$1,627	$214	$1,268	$3	$1,485
Liabilities								
Derivative liabilities - commodity contracts	$(18)	$(158)	$—	$(176)	$(13)	$(100)	$—	$(113)
Derivative liabilities - FTRs	—	—	(10)	(10)	—	—	(11)	(11)
Total liabilities	$(18)	$(158)	$(10)	$(186)	$(13)	$(100)	$(11)	$(124)
Net assets (liabilities)[3]	$451	$978	$12	$1,441	$201	$1,168	$(8)	$1,361

(1) NDT funds hold equity portfolios whose performance is benchmarked against the Alerian MLP Index or the Wells Fargo Hybrid and Preferred Securities REIT index.
(2) Primarily consists of short-term cash investments.
(3) Excludes $(36) million and $9 million as of September 30, 2014 and December 31, 2013, respectively, of receivables, payables, taxes and accrued income associated with the financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of FTRs held by FES and classified as Level 3 in the fair value hierarchy for the periods ended September 30, 2014 and December 31, 2013:

	Derivative Asset FTRs	Derivative Liability FTRs	Net FTRs
	(In millions)		
January 1, 2013 Balance	$6	$(6)	$—
Unrealized loss	—	(2)	(2)
Purchases	5	(12)	(7)
Settlements	(8)	9	1
December 31, 2013 Balance	$3	$(11)	$(8)
Unrealized gain	23	6	29
Purchases	15	(17)	(2)
Settlements	(19)	12	(7)
September 30, 2014 Balance	$22	$(10)	$12

Level 3 Quantitative Information

The following table provides quantitative information for FTRs held by FES that are classified as Level 3 in the fair value hierarchy for the period ended September 30, 2014:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$12	Model	RTO auction clearing prices	($4.60) to $17.70	$1.00	Dollars/MWH

INVESTMENTS

All temporary cash investments purchased with an initial maturity of three months or less are reported as cash equivalents on the Consolidated Balance Sheets at cost, which approximates their fair market value. Investments other than cash and cash equivalents include held-to-maturity securities, AFS securities and notes receivable.

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

Unrealized gains and losses on AFS securities are recognized in AOCI. However, unrealized losses held in the NDTs of FES, OE and TE are recognized in earnings since the trust arrangements, as they are currently defined, do not meet the required ability and intent to hold criteria in consideration of OTTI.

The investment policy for the NDT funds restricts or limits the trusts' ability to hold certain types of assets including private or direct placements, warrants, securities of FirstEnergy, investments in companies owning nuclear power plants, financial derivatives, securities convertible into common stock and securities of the trust funds' custodian or managers and their parents or subsidiaries.

AFS Securities

FirstEnergy holds debt and equity securities within its NDT, nuclear fuel disposal and NUG trusts. These trust investments are considered AFS securities, recognized at fair market value. FirstEnergy has no securities held for trading purposes.

The following table summarizes the amortized cost basis, unrealized gains (there were no unrealized losses) and fair values of investments held in NDT, nuclear fuel disposal and NUG trusts as of September 30, 2014 and December 31, 2013:

	September 30, 2014[1]			December 31, 2013[2]		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
	(In millions)					
Debt securities						
FirstEnergy	$1,777	$33	$1,810	$1,881	$33	$1,914
FES	845	14	859	918	17	935
Equity securities						
FirstEnergy	$628	$82	$710	$308	$9	$317
FES	420	48	468	207	—	207

(1) Excludes short-term cash investments: FE Consolidated - $87 million; FES - $54 million.
(2) Excludes short-term cash investments: FE Consolidated - $204 million; FES - $135 million.

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Proceeds from the sale of investments in AFS securities, realized gains and losses on those sales, OTTI and interest and dividend income for the three months and nine months ended September 30, 2014 and 2013 were as follows:

Three Months Ended

September 30, 2014	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	$347	$30	$(14)	$(7)	$24
FES	183	24	(13)	(6)	14

September 30, 2013	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	$368	$9	$(15)	$(21)	$26
FES	164	5	(3)	(21)	16

Nine Months Ended

September 30, 2014	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	$1,511	$93	$(45)	$(10)	$73
FES	890	73	(30)	(9)	43

September 30, 2013	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	$1,545	$49	$(31)	$(74)	$74
FES	650	38	(14)	(66)	44

Held-To-Maturity Securities

The following table provides the amortized cost basis, unrealized gains (there were no unrealized losses) and approximate fair values of investments in held-to-maturity securities as of September 30, 2014 and December 31, 2013:

	September 30, 2014			December 31, 2013		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
	(In millions)					
Debt Securities						
FirstEnergy	$19	$6	$25	$33	$2	$35

The held-to-maturity debt securities contractually mature by June 30, 2017. Investments in employee benefit trusts and cost and equity method investments, including FirstEnergy's investment in Global Holding, totaling $633 million as of September 30, 2014 and $636 million as of December 31, 2013, are excluded from the amounts reported above.

LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS

All borrowings with initial maturities of less than one year are defined as short-term financial instruments under GAAP and are reported as Short-term borrowings on the Consolidated Balance Sheets at cost. Since these borrowings are short-term in nature, FirstEnergy believes that their costs approximate their fair market value. The following table provides the approximate fair value and related carrying amounts of long-term debt and other long-term obligations, excluding capital lease obligations and net unamortized premiums and discounts:

	September 30, 2014		December 31, 2013	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
FirstEnergy	$19,757	$21,363	$17,049	$17,957
FES	3,148	3,296	3,001	3,073

The fair values of long-term debt and other long-term obligations reflect the present value of the cash outflows relating to those securities based on the current call price, the yield to maturity or the yield to call, as deemed appropriate at the end of each respective period. The yields assumed were based on securities with similar characteristics offered by corporations with credit ratings similar to those of FirstEnergy. FirstEnergy classified short-term borrowings, long-term debt and other long-term obligations as Level 2 in the fair value hierarchy as of September 30, 2014 and December 31, 2013.

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 Gain (Loss) on Debt Redemptions in the Consolidated Statement of Income in the first nine months of 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 PCRB's at maturity.

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 company 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 utility 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.

9. DERIVATIVE INSTRUMENTS

FirstEnergy is exposed to financial risks resulting from fluctuating interest rates and commodity prices, including prices for electricity, natural gas, coal and energy transmission. To manage the volatility relating to these exposures, FirstEnergy's Risk Policy Committee, comprised of senior management, provides general management oversight for risk management activities throughout FirstEnergy. The Risk Policy Committee is responsible for promoting the effective design and implementation of sound risk management programs and oversees compliance with corporate risk management policies and established risk management practice. FirstEnergy also uses a variety of derivative instruments for risk management purposes including forward contracts, options, futures contracts and swaps.

FirstEnergy accounts for derivative instruments on its Consolidated Balance Sheets at fair value unless they meet the normal purchases and normal sales criteria. Derivatives that meet those criteria are accounted for under the accrual method of accounting, and their effects are included in earnings at the time of contract performance. Changes in the fair value of derivative instruments that qualified and were designated as cash flow hedge instruments are recorded in AOCI. Changes in the fair value of derivative instruments that are not designated as cash flow hedge instruments are recorded in earnings on a mark-to-market basis. FirstEnergy has contractual derivative agreements through 2020.

Cash Flow Hedges

FirstEnergy has used cash flow hedges for risk management purposes to manage the volatility related to exposures associated with fluctuating commodity prices and interest rates. The effective portion of gains and losses on a derivative contract is reported as a component of AOCI with subsequent reclassification to earnings in the period during which the hedged forecasted transaction affects earnings.

Total net unamortized gains (losses) included in AOCI associated with instruments previously designated to be in a cash flow hedging relationship totaled $(5) million and $2 million as of September 30, 2014 and December 31, 2013, respectively. Since the forecasted transactions remain probable of occurring, these amounts will be amortized into earnings over the life of the hedging instruments. Approximately $5 million is expected to be amortized to income during the next twelve months.

FirstEnergy has used forward starting swap agreements to hedge a portion of the consolidated interest rate risk associated with anticipated issuances of fixed-rate, long-term debt securities of its subsidiaries. These derivatives were treated as cash flow hedges, protecting against the risk of changes in future interest payments resulting from changes in benchmark U.S. Treasury rates between the date of hedge inception and the date of the debt issuance. No forward starting swap agreements accounted for as a cash flow hedge were outstanding as of September 30, 2014 or December 31, 2013. Total pre-tax unamortized losses included in AOCI associated with prior interest rate cash flow hedges totaled $52 million and $59 million as of September 30, 2014 and December 31, 2013, respectively. Based on current estimates, approximately $9 million will be amortized to interest expense during the next twelve months.

As of September 30, 2014 and December 31, 2013, no commodity or interest rate derivatives were designated as cash flow hedges.

Refer to Note 5, Accumulated Other Comprehensive Income, for reclassifications from AOCI during the three and nine months ended September 30, 2014 and 2013.

Fair Value Hedges

FirstEnergy has used fixed-for-floating interest rate swap agreements to hedge a portion of the consolidated interest rate risk associated with the debt portfolio of its subsidiaries. These derivative instruments were treated as fair value hedges of fixed-rate, long-term debt issues, protecting against the risk of changes in the fair value of fixed-rate debt instruments due to lower interest rates. As of September 30, 2014 and December 31, 2013, no fixed-for-floating interest rate swap agreements were outstanding.

Unamortized gains included in long-term debt associated with prior fixed-for-floating interest rate swap agreements totaled $35 million and $44 million as of September 30, 2014 and December 31, 2013, respectively. Based on current estimates, approximately $12 million will be amortized to interest expense during the next twelve months. Reclassifications from long-term debt into interest expense totaled approximately $3 million and $4 million during the three months ended September 30, 2014 and 2013, respectively, and $9 million and $15 million during the nine months ended September 30, 2014 and 2013, respectively.

As of September 30, 2014 and December 31, 2013, no commodity or interest rate derivatives were designated as fair value hedges.

Commodity Derivatives

FirstEnergy uses both physically and financially settled derivatives to manage its exposure to volatility in commodity prices. Commodity derivatives are used for risk management purposes to hedge exposures when it makes economic sense to do so, including circumstances where the hedging relationship does not qualify for hedge accounting.

Electricity forwards are used to balance expected sales with expected generation and purchased power. Natural gas futures are entered into based on expected consumption of natural gas primarily for use in FirstEnergy’s combustion turbine units. Heating oil futures are entered into based on expected consumption of oil and the financial risk in FirstEnergy’s coal transportation contracts. Derivative instruments are not used in quantities greater than forecasted needs.

As of September 30, 2014, FirstEnergy’s net asset position under commodity derivative contracts was $12 million, which related to FES positions. Under these commodity derivative contracts, FES posted $46 million of collateral. Certain commodity derivative contracts include credit risk related contingent features that would require FES to post $20 million of additional collateral if the credit rating for its debt were to fall below investment grade.

Based on commodity derivative contracts held as of September 30, 2014, an adverse change of 10% in commodity prices would decrease net income by approximately $4 million during the next twelve months.

Interest Rate Swaps

During the second quarter of 2014, FE executed notional $500 million of forward-starting, pay-fixed/receive-float, interest rate swaps with an effective date of December 31, 2015 and a weighted average 10-year fixed rate of 3.21%. On June 10, 2014, the interest rate swaps were terminated resulting in a realized gain and cash proceeds of approximately $6 million. The realized gain is recorded as a reduction to interest expense in the Consolidated Statements of Income.

NUGs

As of September 30, 2014, FirstEnergy's net liability position under NUG contracts was $155 million, representing contracts held at JCP&L, ME and PN. NUG contracts represent purchased power agreements with third-party non-utility generators that are transacted to satisfy certain obligations under PURPA. Changes in the fair value of NUG contracts are subject to regulatory accounting treatment and do not impact earnings.

LCAPP

The LCAPP law was enacted in New Jersey during 2011 to promote the construction of qualified electric generation facilities. JCP&L maintained two LCAPP contracts, which were financially settled agreements that allowed eligible generators to receive payments from, or make payments to, JCP&L pursuant to an annually calculated load-ratio share of the capacity produced by the generator based upon the annual forecasted peak demand as determined by PJM. JCP&L expected to recover from its customers payments made to the generators and give credit to customers for payments from the generators under these contracts. As a result, the projected future obligations for the LCAPP contracts were considered derivative liabilities with a corresponding regulatory asset. Since the LCAPP contracts were subject to regulatory accounting, changes in their fair value did not impact earnings. On October 11, 2013, the U.S. District Court for the District of New Jersey declared that the LCAPP was preempted by the FPA and unconstitutional. Consistent with the provisions of the LCAPP contracts, the U.S. District Court's ruling was a termination event. During the fourth quarter of 2013, JCP&L issued termination notices to the counterparties and reversed the derivative liability and corresponding regulatory asset on its Consolidated Balance Sheet. On October 22, 2013, the Superior Court of New Jersey Appellate Division dismissed two consolidated appeals which had been taken from the final order of the NJBPU which accepted and adopted the recommendation of the NJBPU's Agent regarding implementation of the LCAPP law. Dismissal of the consolidated appeals, along with pending matters currently on remand to the NJBPU, was without prejudice subject to the parties exercising their appellate rights in the federal courts. The parties filed an appeal with the U.S. Court of Appeals for the Third Circuit and briefing by the parties was completed by March 5, 2014. On September 11, 2014, the US Court of Appeals for the Third Circuit upheld the U.S. District Court's ruling that invalidated the LCAPP program on narrower grounds.

FTRs

As of September 30, 2014, FirstEnergy's and FES's net asset position under FTRs was $24 million and $12 million, respectively, and FES posted $5 million of collateral. FirstEnergy holds FTRs that generally represent an economic hedge of future congestion charges that will be incurred in connection with FirstEnergy’s load obligations. FirstEnergy acquires the majority of its FTRs in an annual auction through a self-scheduling process involving the use of ARRs allocated to members of an RTO that have load serving obligations and through the direct allocation of FTRs from the PJM RTO. The PJM RTO has a rule that allows directly allocated FTRs to be granted to LSEs in zones that have newly entered PJM. For the first two planning years, PJM permits the LSEs to request a direct allocation of FTRs in these new zones at no cost as opposed to receiving ARRs. The directly allocated FTRs differ from traditional FTRs in that the ownership of all or part of the FTRs may shift to another LSE if customers choose to shop with the other LSE.

The future obligations for the FTRs acquired at auction are reflected on the Consolidated Balance Sheets and have not been designated as cash flow hedge instruments. FirstEnergy initially records these FTRs at the auction price less the obligation due to the RTO, and subsequently adjusts the carrying value of remaining FTRs to their estimated fair value at the end of each accounting period prior to settlement. Changes in the fair value of FTRs held by FES and AE Supply are included in other operating expenses as unrealized gains or losses. Unrealized gains or losses on FTRs held by FirstEnergy’s utilities are recorded as regulatory assets or liabilities. Directly allocated FTRs are accounted for under the accrual method of accounting, and their effects are included in earnings at the time of contract performance.

FirstEnergy records the fair value of derivative instruments on a gross basis. The following table summarizes the fair value and classification of derivative instruments on FirstEnergy's Consolidated Balance Sheets:

Derivative Assets			Derivative Liabilities		
	Fair Value			Fair Value	
	September 30, 2014	December 31, 2013		September 30, 2014	December 31, 2013
	(In millions)			(In millions)	
Current Assets - Derivatives			Current Liabilities - Derivatives		
Commodity Contracts	$146	$162	Commodity Contracts	$(156)	$(102)
FTRs	34	4	FTRs	(10)	(9)
	180	166		(166)	(111)
			Noncurrent Liabilities - Adverse Power Contract Liability		
Deferred Charges and Other Assets - Other			NUGs	(157)	(222)
Commodity Contracts	42	53	Noncurrent Liabilities - Other		
FTRs	1	—	Commodity Contracts	(20)	(11)
NUGs	2	20	FTRs	(1)	(3)
	45	73		(178)	(236)
Derivative Assets	$225	$239	Derivative Liabilities	$(344)	$(347)

FirstEnergy enters into contracts with counterparties that allow for net settlement of derivative assets and derivative liabilities. Certain of these contracts contain margining provisions that require the use of collateral to mitigate credit exposure between FirstEnergy and these counterparties. In situations where collateral is pledged to mitigate exposures related to derivative and non-derivative instruments with the same counterparty, FirstEnergy allocates the collateral based on the percentage of the net fair value of derivative instruments to the total fair value of the combined derivative and non-derivative instruments. The following tables summarize the fair value of derivative instruments on FirstEnergy's Consolidated Balance Sheets and the effect of netting arrangements and collateral on its financial position:

		Amounts Not Offset in Consolidated Balance Sheet		
September 30, 2014	Fair Value	Derivative Instruments	Cash Collateral (Received)/Pledged	Net Fair Value
	(In millions)			
Derivative Assets				
Commodity contracts	$188	$(139)	$—	$49
FTRs	35	(11)	—	24
NUG contracts	2	—	—	2
	$225	$(150)	$—	$75

Derivative Liabilities				
Commodity contracts	$(176)	$139	$16	$(21)
FTRs	(11)	11	—	—
NUG contracts	(157)	—	—	(157)
	$(344)	$150	$16	$(178)

December 31, 2013	Fair Value	Amounts Not Offset in Consolidated Balance Sheet Derivative Instruments	Cash Collateral (Received)/Pledged	Net Fair Value
	(In millions)			
Derivative Assets				
Commodity contracts	$215	$(106)	$(9)	$100
FTRs	4	(4)	—	—
NUG contracts	20	—	—	20
	$239	$(110)	$(9)	$120
Derivative Liabilities				
Commodity contracts	$(113)	$106	$7	$—
FTRs	(12)	4	5	(3)
NUG contracts	(222)	—	—	(222)
	$(347)	$110	$12	$(225)

The following table summarizes the volumes associated with FirstEnergy's outstanding derivative transactions as of September 30, 2014:

	Purchases	Sales	Net	Units
	(In millions)			
Power Contracts	24	32	(8)	MWH
FTRs	63	—	63	MWH
NUGs	6	—	6	MWH
Natural Gas	40	1	39	mmBTU

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The effect of derivative instruments not in a hedging relationship on FirstEnergy's Consolidated Statements of Income during the three months ended September 30, 2014 and 2013, are summarized in the following tables:

	Three Months Ended September 30			
	Commodity Contracts	FTRs	Interest Rate Swaps	Total
	(In millions)			
2014				
Unrealized Gain (Loss) Recognized in:				
Other Operating Expense [(1)]	$(24)	$4	$—	$(20)
Realized Gain (Loss) Reclassified to:				
Revenues [(2)]	$3	$11	$—	$14
Purchased Power Expense [(3)]	(63)	—	—	(63)
Other Operating Expense [(4)]	—	(13)	—	(13)
Fuel Expense	(8)	—	—	(8)

[(1)] Includes ($24) million for commodity contracts and $3 million for FTRs associated with FES.
[(2)] Represents losses on structured financial contracts. Includes $3 million for commodity contracts and $11 million for FTRs associated with FES.
[(3)] Realized gains on financially settled wholesale contracts of $74 million were netted in purchased power. Includes ($63) million for commodity contracts associated with FES.
[(4)] Includes ($14) million for FTRs associated with FES.

	Three Months Ended September 30			
	Commodity Contracts	FTRs	Interest Rate Swaps	Total
	(In millions)			
2013				
Unrealized Gain (Loss) Recognized in:				
Other Operating Expense [(5)]	$11	$(8)	$—	$3
Realized Gain (Loss) Reclassified to:				
Revenues [(6)]	$14	$6	$—	$20
Purchased Power Expense [(7)]	(17)	—	—	(17)
Other Operating Expense [(8)]	—	(10)	—	(10)
Fuel Expense	(2)	—	—	(2)

[(5)] Includes $10 million for commodity contracts and ($8) million for FTRs associated with FES.
[(6)] Includes $14 million for commodity contracts and $6 million for FTRs associated with FES.
[(7)] Includes ($17) million for commodity contracts associated with FES.
[(8)] Includes ($9) million for FTRs associated with FES.

	Nine Months Ended September 30			
	Commodity Contracts	FTRs	Interest Rate Swaps	Total
	(In millions)			
2014				
Unrealized Gain (Loss) Recognized in:				
Other Operating Expense(1)	$(82)	$22	$—	$(60)
Realized Gain (Loss) Reclassified to:				
Revenues(2)	$(8)	$62	$—	$54
Purchased Power Expense(3)	395	—	—	395
Other Operating Expense(4)	—	(30)	—	(30)
Fuel Expense	3	—	—	3
Interest Expense	—	—	6	6

(1) Includes ($82) million for commodity contracts and $21 million for FTRs associated with FES.
(2) Represents losses on structured financial contracts. Includes ($8) million for commodity contracts and $61 million for FTRs associated with FES.
(3) Realized losses on financially settled wholesale contracts of $263 million resulting from higher market prices were netted in purchased power. Includes $395 million for commodity contracts associated with FES.
(4) Includes ($30) million for FTRs associated with FES.

	Nine Months Ended September 30			
	Commodity Contracts	FTRs	Interest Rate Swaps	Total
	(In millions)			
2013				
Unrealized Loss Recognized in:				
Other Operating Expense(5)	$(5)	$(10)	$—	$(15)
Realized Gain (Loss) Reclassified to:				
Revenues(6)	$29	$19	$—	$48
Purchased Power Expense(7)	(30)	—	—	(30)
Other Operating Expense(8)	—	(28)	—	(28)

(5) Includes ($5) million for commodity contracts and ($10) million for FTRs associated with FES.
(6) Includes $29 million for commodity contracts and $17 million for FTRs associated with FES.
(7) Includes ($30) million for commodity contracts associated with FES.
(8) Includes ($25) million for FTRs associated with FES.

The unrealized and realized gains (losses) on FirstEnergy's derivative instruments subject to regulatory accounting during the three months and nine months ended September 30, 2014 and 2013, are summarized in the following tables:

Derivatives Not in a Hedging Relationship with Regulatory Offset	Three Months Ended September 30			
	NUGs	LCAPP[1]	Regulated FTRs	Total
	(In millions)			
2014				
Unrealized Gain (Loss) on Derivative Instrument	$(9)	$—	$6	$(3)
Realized Gain (Loss) on Derivative Instrument	23	—	(5)	18
2013				
Unrealized Gain (Loss) on Derivative Instrument	$7	$(8)	$1	$—
Realized Gain (Loss) on Derivative Instrument	14	—	(1)	13

Derivatives Not in a Hedging Relationship with Regulatory Offset	Nine Months Ended September 30			
	NUGs	LCAPP[1]	Regulated FTRs	Total
	(In millions)			
2014				
Unrealized Gain on Derivative Instrument	$17	$—	$21	$38
Realized Gain (Loss) on Derivative Instrument	30	—	(10)	20
2013				
Unrealized Gain (Loss) on Derivative Instrument	$(13)	$(22)	$1	$(34)
Realized Gain (Loss) on Derivative Instrument	57	—	(1)	56

[1] During the fourth quarter of 2013, all LCAPP contracts were terminated as discussed above.

The following tables provide a reconciliation of changes in the fair value of certain contracts that are deferred for future recovery from (or credit to) customers during the three months and nine months ended September 30, 2014 and 2013:

Derivatives Not in a Hedging Relationship with Regulatory Offset	Three Months Ended September 30 NUGs	LCAPP[1]	Regulated FTRs	Total
	(In millions)			
Outstanding net asset (liability) as of July 1, 2014	$(169)	$—	$10	$(159)
Additions/Change in value of existing contracts	(9)	—	6	(3)
Settled contracts	23	—	(5)	18
Outstanding net asset (liability) as of September 30, 2014	$(155)	$—	$11	$(144)
Outstanding net liability as of July 1, 2013	$(231)	$(158)	$—	$(389)
Additions/Change in value of existing contracts	7	(8)	1	—
Settled contracts	14	—	(1)	13
Outstanding net liability as of September 30, 2013	$(210)	$(166)	$—	$(376)

Derivatives Not in a Hedging Relationship with Regulatory Offset	Nine Months Ended September 30 NUGs	LCAPP[1]	Regulated FTRs	Total
	(In millions)			
Outstanding net liability as of January 1, 2014	$(202)	$—	$—	$(202)
Additions/Change in value of existing contracts	17	—	21	38
Settled contracts	30	—	(10)	20
Outstanding net asset (liability) as of September 30, 2014	$(155)	$—	$11	$(144)
Outstanding net liability as of January 1, 2013	$(254)	$(144)	$—	$(398)
Additions/Change in value of existing contracts	(13)	(22)	1	(34)
Settled contracts	57	—	(1)	56
Outstanding net liability as of September 30, 2013	$(210)	$(166)	$—	$(376)

[1] During the fourth quarter of 2013, all LCAPP contracts were terminated as discussed above.

10. REGULATORY MATTERS

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 and covered 2009-2011, the first three years of the statutory period. Expenditures were originally estimated to be approximately $101 million for the PE programs for the entire period of 2009-2015. PE's plan for the second three year period, 2012-2014, included additional and improved programs, and was approved by the MDPSC in December 2011. PE filed its third plan, covering the three-year period 2015-2017, on September 2, 2014. The projected costs of the 2015-2017 plan are approximately $64 million for that three year period. The MDPSC held hearings for the utilities' 2015-2017 plans on October 20-24, 2014. 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.

Pursuant to a bill passed by the Maryland legislature in 2011, 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. PE has advised the MDPSC that compliance with the new rules is expected to increase costs by approximately $106 million over the period 2012-2015. On April 1, 2013, the Maryland electric utilities, including PE, filed their first annual reports on compliance with the new rules, and following a hearing, the MDPSC issued an order on September 3, 2013, which accepted PE's filing and the operational changes proposed therein. PE filed its second annual report on March 27, 2014. The MDPSC held a hearing on the utility reports on July 10, 2014, and on August 27, 2014, the MDPSC issued an order accepting PE's second report.

Following a "derecho" storm through the region on June 29, 2012, the MDPSC convened a proceeding to consider matters relating to the electric utilities' performance in responding to the storm. Hearings on the matter were conducted in September 2012. Concurrently, Maryland's governor convened a special panel to examine possible ways to improve the resilience of the electric distribution system. On October 3, 2012, that panel issued a report calling for various measures including: acceleration and expansion of some of the requirements contained in the reliability standards which had become final on May 28, 2012; selective increased investment in system hardening; creation of separate recovery mechanisms for the costs of those changes and investments; and penalties or bonuses on returns earned by the utilities based on their reliability performance. On February 27, 2013, the MDPSC issued an order (the February 27 Order) requiring the utilities to submit several reports over a series of months, 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 responded to the requirements in the order consistent with the schedule set forth therein. 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 a written Order issued July 31, 2012, the NJBPU found that a base rate proceeding "will assure that JCP&L's rates are just and reasonable and that JCP&L is investing sufficiently to assure the provision of safe, adequate and proper utility service to its customers" and ordered JCP&L to file a base rate case using a historical 2011 test year. The rate case petition was filed on November 30, 2012 by JCP&L requesting approval to increase revenues by approximately $31 million, which included the recovery of 2011 storm costs but excluded approximately $603 million of costs incurred in 2012 associated with the impact of Hurricane Sandy. The NJBPU transmitted the case to the New Jersey Office of Administrative Law for further proceedings and an ALJ was assigned. Hearings in the rate case concluded in November 2013. In the initial briefs of the parties filed on January 27, 2014, 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). Reply briefs were filed on February 24, 2014. 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, and the matter is pending before the ALJ. On July 24, 2014, the Division of Rate Counsel filed a motion with the NJBPU requesting that effective August 1, 2014, JCP&L's existing rates be continued on a provisional basis until the NJBPU's final order in the base rate case and subject to refund. JCP&L filed a brief opposing the motion on August 4, 2014, and the Division of Rate Counsel filed a reply to JCP&L's opposition on August 8, 2014. On September 30, 2014, the NJBPU granted the request of the ALJ to extend the time for an initial decision in the base rate case until November 13, 2014.

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 on August 18, 2014. 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. Although FirstEnergy is still reviewing the CTA Order, by our interpretation and calculation, FirstEnergy expects that application of the modified policy in the pending JCP&L base rate case would reduce the CTA revenue adjustment as proposed by certain parties to the case from approximately $56 million to approximately $5 to $6 million.

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 in the May 31 clarification 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, consistent with NJBPU's orders, JCP&L filed the 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) in the fourth quarter of 2013. By its Order of March 19, 2014, the NJBPU approved the Stipulation of Settlement and on March 25, 2014, transmitted a copy of that Order to the Office of Administrative Law so that “actual recovery of the 2011 costs can be determined in relation to the pending base rate case.” Recovery of 2011 storm costs will be addressed in the pending base rate case and are included in JCP&L's May 5, 2014, proposed rate increase; while recovery of 2012 storm costs 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 existing 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 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 to the Supreme Court of Ohio were filed by the Northeast Ohio Public Energy Council and the ELPC. While briefing has been completed, the matter has not yet been scheduled for oral argument. Northeast Ohio Public Energy Council and the ELPC filed a motion to expedite the oral argument on August 28, 2014. The Ohio Companies responded opposing the motion on September 8, 2014. On October 8, 2014, the Supreme Court of Ohio denied the Northeast Ohio Public Energy Council and ELPC's motion to expedite the 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 evidentiary hearing on the ESP IV is currently scheduled to commence January 20, 2015. The material terms of the proposed plan include:

- Continuing a base distribution rate freeze through May 31, 2019;
- Continues 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 R.C. 4928.66 (codification of SB221), and the Ohio Companies' filing of amended energy efficiency plans under SB310, the Ohio Companies are required to implement energy efficiency programs that achieve a total annual energy savings equivalent of approximately 1,200 GWHs in 2012, 1,705 GWHs in 2013, and 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. The Ohio Companies filed annual status reports in 2013 and 2014 indicating their compliance with the statutory energy efficiency and peak demand reduction benchmarks in 2012 and 2013, respectively.

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 bidding energy efficiency and demand response 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 under the basis that the PUCO's authorization for the Ohio Companies to share in the PJM revenues was unlawful. The PUCO granted rehearing on September 11, 2013 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. The PUCO has sixty days to review and approve, or modify and approve, the amended plan.

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. The Ohio Companies' response was filed on November 4, 2013. The motion is still pending and additional briefing has followed. While briefing has been completed, the matter has not been scheduled for oral argument.

R.C. 4928.64 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 the renewable energy requirements established under SB221. 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 and selected auditors to perform a financial and management audit. Final audit reports filed with the PUCO generally supported the Ohio Companies' approach to procurement of RECs, but also recommended the PUCO examine, for possible disallowance, certain costs associated with the procurement of in-state renewable obligations that the auditor characterized as excessive. Following the hearing, 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, and to file tariff schedules reflecting the refund and interest costs within 60 days following the issuance of a final appealable order on the basis that the Ohio Companies did not prove such purchases were prudent. The Ohio Companies, along with other parties, timely filed applications for rehearing on September 6, 2013. On December 18, 2013, the PUCO denied all of the applications for rehearing. 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, the Ohio Companies filed a notice of appeal and a motion for stay of the PUCO's order with the Supreme Court of Ohio. On February 10, 2014, the Supreme Court of Ohio granted the Ohio Companies' motion for stay, which went into effect on February 14, 2014.

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. On April 15, 2014, the Supreme Court of Ohio stayed the briefing schedule pending the court's resolution of the Ohio Companies' motion to seal certain confidential portions of the appendix and supplement to their merit brief. On May 6, 2014, the PUCO issued an Entry extending the confidential treatment to February 13, 2015, of all materials and information previously granted confidential treatment. On September 3, 2014, the Supreme Court of Ohio ruled that the documents filed under seal will be maintained under seal pursuant to Supreme Court rules, and that the briefing schedule should recommence.

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. While approving the settlement, the PPUC, however, also denied the Pennsylvania Companies' proposal to recover NITS on a non-bypassable basis.

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 a 29-month period that began in January of 2011. 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. The balance of marginal transmission losses was fully refunded to customers by the second quarter of 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. One judge dissented, writing that the Pennsylvania authorities improperly interpreted a matter outside of their jurisdiction and that was in FERC's exclusive jurisdiction (the PJM tariff meaning of line losses), and that preclusion therefore does not apply. 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 are evaluating next steps, including a possible appeal to the U.S. Supreme Court.

Pennsylvania adopted Act 129 in 2008 to address issues such as: energy efficiency and peak load reduction; generation procurement; time-of-use rates; smart meters; and alternative energy. Among other things, Act 129 required utilities to file with the PPUC an energy efficiency and peak load reduction plan (EE&C Plan) by July 1, 2009, setting forth the utilities' plans to reduce energy consumption by a minimum of 1% and 3% by May 31, 2011 and May 31, 2013, respectively, and to reduce peak demand by a minimum of 4.5% by May 31, 2013. Act 129 provides for potentially significant financial penalties between $1 and $20 million to be assessed on utilities that fail to achieve the required reductions in consumption and peak demand. The Pennsylvania Companies submitted reports in November 2011 and November 2013, in which they reported on their compliance with the statutory benchmarks. On March 20, 2014, the PPUC issued an Order initially determining that ME, PN and Penn achieved the 2011 and 2013 statutory energy efficiency benchmarks and that WP was in compliance with the 2013 statutory energy efficiency and peak demand benchmarks but was not in compliance with the 2011 energy efficiency benchmarks. The PPUC referred the matter of WP's compliance with the 2011 statutory benchmarks, to the PPUC Bureau of Investigation and Enforcement for the initiation of an appropriate proceeding by May 30, 2014 to investigate whether WP is subject to statutory penalties. The initial determination would be deemed final unless any petitions challenging its initial determination were filed within 20 days of the Order. On April 9, 2014, WP filed a petition challenging the PPUC’s initial determination arguing, among other things, that the May 2011 target was not mandatory and WP was in compliance because it achieved its May 2013 targets. On April 21, 2014, WP filed an appeal with the Commonwealth Court of Pennsylvania challenging the PPUC's initial finding of a violation of Act 129 on due process grounds. The Bureau of Investigation and Enforcement also initiated a proceeding by filing a Complaint against WP in which it alleged that WP violated Act 129 and recommended a penalty in the amount of $11.4 million. On August 22, 2014, the PPUC entered an Order approving a joint petition for settlement filed on July 30, 2014, that resolved all issues in the pending proceedings, and included WP making a payment of $1.3 million to the PPUC. On September 9, 2014, WP submitted the $1.3 million payment to the PPUC and withdrew the Commonwealth Court appeal and the petition before the PPUC challenging its initial findings thereby concluding these matters.

Pursuant to Act 129, the PPUC was charged with reviewing the cost effectiveness of energy efficiency and peak demand reduction programs. The PPUC found the energy efficiency programs to be cost effective and 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 until it receives more information from the EE&C statewide evaluator, and therefore 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 also 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.

In the PPUC Order approving the FirstEnergy and AE merger, the PPUC announced that a separate statewide investigation into Pennsylvania's retail electricity market would be conducted with the goal of making recommendations for improvements to ensure that a properly functioning and workable competitive retail electricity market exists in the state. On April 29, 2011, the PPUC entered an Order initiating the investigation and requesting comments from interested parties on eleven directed questions concerning retail markets in Pennsylvania to investigate both intermediate and long term plans that could be adopted to further foster the competitive markets, and to explore the future of default service in Pennsylvania following the expiration of the upcoming DSPs on May 31, 2015. A final order was issued on February 15, 2013, providing recommendations on the entities to provide default service, the products to be offered, billing options, customer education, and licensing fees and assessments, among other items. Subsequently, the PPUC established five workgroups and one comment proceeding in order to seek resolution of certain matters and to clarify certain obligations that arose from that order.

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. The filings also propose several new cost recovery riders as well as revisions to certain existing cost recovery riders. An order on the proposed increases is expected in May 2015.

WEST VIRGINIA

MP and PE currently operate under a Joint Stipulation and Agreement of Settlement reached with the other parties and approved by the WVPSC in June 2010 that provided for:

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

On April 30, 2014, MP and PE filed a rate case requesting a base rate increase of approximately $96 million, or 9.3%, based on an historic 2013 test year. The filing also included a surcharge to recover costs of MP's and PE's vegetation management program in the amount of approximately $48 million. On June 13, 2014, MP and PE amended their filing to add an additional $7.5 million of additional revenues to reimburse their expected costs of implementing monthly meter reading for residential and small commercial customers, resulting in a proposed total rate increase request of approximately $152 million, or 14.7%. On November 3, 2014, a Joint Stipulation was submitted by all parties which resolves all issues in the pending proceeding and 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 operating and maintenance expenses and capital costs related to a new vegetation maintenance program; authority to establish a regulatory asset for MATS investments placed into service in 2016 and 2017 and recover in the next base rate case; authority to defer, amortize and recover over a 5-year period approximately $46 million of restoration costs associated with the 2012 Derecho and Hurricane Sandy storms; and elimination of the Temporary Transaction Surcharge and movement of the costs currently being collected for the 2013 Harrison generation transaction into base rates effective February 25, 2015. The settlement is subject to review and approval of the WVPSC. The WVPSC has scheduled a hearing for November 7, 2014, to evaluate the settlement and its terms.

On August 29, 2014, MP and PE filed their annual ENEC case proposing an approximate $65.8 million annual increase in rates, which is a 5.7% overall increase over existing rates. The $65.8 million 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. This proceeding includes a two-year review period as there was not an annual ENEC filing in 2013 pursuant to party agreement and WVPSC consent during MP and PE’s 2013 proceeding authorizing the Harrison/Pleasants asset transfer. An order is expected to be issued before the end of 2014.

RELIABILITY MATTERS

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

FirstEnergy believes that it is in compliance with all currently-effective and enforceable reliability standards. Nevertheless, in the course of operating its extensive electric utility systems and facilities, FirstEnergy occasionally learns of isolated facts or circumstances that could be interpreted as excursions from the reliability standards. If and when such items are found, FirstEnergy develops information about the item and develops a remedial response to the specific circumstances, including in appropriate cases “self-reporting” an item to RFC. Moreover, it is clear that the NERC, RFC and FERC will continue to refine existing reliability standards as well as to develop and adopt new reliability standards. Any inability on FirstEnergy's part to comply with the reliability standards for its bulk power system could result in the imposition of financial penalties that could have a material adverse effect on its financial condition, results of operations and cash flows.

FERC MATTERS

PJM Transmission Rates

PJM and its stakeholders have been debating the proper method to allocate costs for new transmission facilities. While FirstEnergy and other parties advocated for a traditional "beneficiary pays" (or usage based) approach, others advocate for “socializing” the costs on a load-ratio share basis, 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 U.S. Court of Appeals for 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 by means of a "postage-stamp" rate. 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 them, and not based on load-ratio share in PJM as a whole. The court remanded the case to FERC for further proceedings to implement its findings and ruling. On September 5, 2014, the Seventh Circuit denied a petition for rehearing and rehearing en banc of the panel's decision.

Order No. 1000, issued by FERC on July 21, 2011, announced new policies regarding transmission planning and transmission cost allocation. Order No. 1000 required the submission of a compliance filing by PJM or the PJM transmission owners demonstrating that the cost allocation methodology for new transmission projects directed by the PJM Board of Managers satisfied the principles set forth in the order. On August 15, 2014 the D.C. Circuit affirmed Order No. 1000 in every respect, including its termination of certain "right of first refusal" privileges discussed in more detail below. On October 17, 2014, the court denied a request for rehearing that had been filed by representatives of certain public power entities.

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 D.C. Circuit.

To demonstrate compliance with the regional cost allocation principles of Order No. 1000, the PJM transmission owners, including FirstEnergy, submitted a filing to FERC proposing a hybrid method of 50% beneficiary pays and 50% postage stamp to be effective for RTEP projects approved by the PJM Board of Managers on, and after, the effective date of the compliance filings. FERC approved the filing, subject to additional compliance filings. Requests for rehearing by certain parties remain pending. Separately, the PJM transmission owners, including FirstEnergy, submitted filings to FERC setting forth the cost allocation method for projects that cross the borders between: (1) the PJM region and the NYISO region; and (2) the PJM region and 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. On the same date, also in response to Order No. 1000, the PJM transmission owners, including FirstEnergy, also submitted to FERC a filing stating 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. On December 30, 2013, FERC conditionally accepted the PJM/SERTP cross-border project cost allocation filing, subject to refund and future orders in PJM's and the SERTP region participants' related Order No. 1000 interregional compliance proceedings. The PJM/NYISO and PJM/MISO cross-border project cost allocation filings remain 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. The move was performed as planned with no known operational or reliability issues for ATSI or for the wholesale transmission customers in the ATSI zone. While many of the matters involved with the move have been resolved, FERC denied recovery by means of 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 that demonstrates net benefits to customers from the move. On December 21, 2012, ATSI and other parties filed a proposed settlement agreement with FERC to resolve the exit fee and transmission cost allocation issues. However, FERC subsequently rejected that settlement, 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. On October 21, 2013, FirstEnergy filed a request for rehearing of FERC's order, which 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. A separate but related issue is the allocation of certain congestion revenue rights (described as "MISO LTTRs") that result from constructing MVP projects. Although MISO and the MISO transmission owners agree that the ATSI zone should pay for the Michigan Thumb MVP project, they submitted a proposed tariff that, among other things, would have the effect of depriving ATSI of ATSI’s share of the most valuable class of MISO LTTRs associated with that project. ATSI protested this proposal but, on September 18, 2014, FERC issued an order approving the MISO LTTR proposal. On October 20, 2014, ATSI requested rehearing of FERC’s September 18, 2014 order.

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 a 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. ATSI has requested FERC approval of the proposal with an effective date of January 1, 2015. FirstEnergy expects that FERC will issue an initial ruling by the end of 2014.

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 U.S. Court of Appeals for the Ninth Circuit in several pending proceedings to resolve all outstanding refund and other claims, including claims of alleged price manipulation in the California energy markets, during 2000 and 2001. The Ninth

Circuit had previously remanded one of those proceedings to FERC, which dismissed the claims of the California Parties in May 2011, and affirmed the dismissal in June 2012. The California Parties appealed FERC's decision back to the Ninth Circuit, where the appeal remains pending.

In another proceeding, in June 2009, the California Attorney General, on behalf of certain California parties, filed another complaint with FERC against various sellers, including AE Supply, again seeking refunds for transactions in the California energy markets during 2000 and 2001. The above-noted transactions with CDWR are the basis for including AE Supply in this complaint. AE Supply filed a motion to dismiss, which was granted by FERC in May 2011, and affirmed by FERC in June 2012. The California Attorney General 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 it had suspended in February 2011. As a result, approximately $62 million and approximately $59 million in costs incurred by PATH-Allegheny and PATH-WV, respectively, were reclassified from net property, plant and equipment to a regulatory asset for future recovery. On September 28, 2012, those companies requested authorization from FERC to recover the costs with a proposed ROE of 10.9% (10.4% base plus 0.5% for RTO membership) from PJM customers over the next five years. Several parties protested the request. On November 30, 2012, FERC issued an order denying the 0.5% 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 procedures 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 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 suggesting that FERC order that the remaining concerns be addressed in the existing stakeholder process that is described in the PJM/MISO Joint Operating Agreement. FERC has not mandated a solution, and the RTOs and affected parties are working to address the MISO's proposal in stakeholder proceedings. Changes to the criteria and qualifications for participation in the PJM RPM capacity auctions could have a significant impact on the outcome of those auctions, including a negative impact on the prices at which those auctions would clear.

MOPR Reform

On May 2, 2013, FERC issued an order in large part accepting PJM's proposed reform of the MOPR, including two proposed categorical exemptions and applicability to existing resources, and also requiring PJM to commit to future review and, if necessary, additional revisions to the MOPR to accommodate changing market conditions. On June 3, 2013, FirstEnergy submitted a request for rehearing of FERC's May 2, 2013 order. In its rehearing request, FirstEnergy referenced the results of the May 2013 PJM RPM capacity auction, and publicly-available data about the reasons for the unexpectedly low "rest-of-RTO" clearing price of $59 per MW-day, as supporting its contention that the MOPR reform depressed prices as predicted in FirstEnergy's December 28, 2012 and January 25, 2013 comments. FirstEnergy's request for rehearing is pending before FERC.

FTR Underfunding Complaint

In PJM, FTRs are a mechanism to hedge congestion and they 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. Various parties filed responsive pleadings, including PJM. On June 5, 2013, FERC issued its order denying the new complaint. On July 5, 2013, FESC, on behalf of FES and AE Supply, filed a request for rehearing of FERC's order. That request for rehearing, and all subsequent filings in the docket, are pending before FERC. The PJM stakeholders continue to discuss the problem of 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. On September 29, 2014, FESC, on behalf of certain of its affiliates, filed comments supporting the investigation, arguing that tariff changes would decrease the incidence of Up-to Congestion transactions, and funding for FTRs likely would increase.

2013-2014 PJM RPM Tariff Amendments

In November 2013, PJM began to submit a series of amendments to its RPM capacity tariff in order to address certain problems that have been observed in recent auctions. These problems 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. The purpose of PJM’s tariff amendments is 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. In each of the relevant dockets, FirstEnergy and other parties submitted comments largely supporting PJM's proposed amendments. FERC largely approved the 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, and a technical conference announced by FERC regarding the arbitrage/capacity replacement issue has yet to be scheduled.

On August 20, 2014, PJM announced that it is contemplating major revisions to its RPM program for the purpose of addressing issues that were identified in the January 2014 polar vortex. On October 7, 2014, PJM released a document that describes its proposed revisions. Highlights of the proposed revisions include: (i) classifying capacity into two products, Base Capacity and Capacity Performance, and capping the amount of Base Capacity that would be procured; (ii) allowing all Capacity Performance units to offer at the Net Cost-of-New-Entry (Net CONE); (iii) eliminating the "2.5% holdback" in the BRA; (iv) imposing significant new penalties on Performance Capacity units that fail to operate when called by PJM; and (v) suggesting a mechanism to limit price change year-over-year between RPM auctions. PJM expects that these changes will increase the RPM auction clearing prices by a significant amount. FirstEnergy is participating in the stakeholder processes where these PJM proposals are being developed. PJM has announced its plans to file tariff revisions that implement some version of these proposed revisions in time for the May 2015 BRA.

PJM RPM Auctions - Calculation of Unit-Specific Offer Caps

The PJM RPM capacity tariff describes the rules for calculating the "offer cap" for each unit that offers into the RPM auctions. In summary, the offer cap is calculated by identifying certain going-forward costs, including the going-forward capital requirements, for a given unit, and then subtracting the projected energy and ancillary services revenues, net of marginal costs, from the going-forward costs. The remainder becomes the offer cap. FES disagreed with the Market Monitor's approach for calculating the offer caps, and earlier in 2014, FES asked FERC to determine which tariff interpretation, FES or the 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. FERC directed PJM to file a brief by November 3, 2014 explaining why the existing tariff language is just and reasonable, and that responsive briefs are due thirty days after PJM files its brief.

PJM Market Reform: FERC Order No. 745 - Demand Response
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, just as if DR were a traditional energy resource. The majority concluded that DR is a retail service, and therefore falls under state, and not federal, jurisdiction, and that FERC therefore lacked jurisdiction to regulate DR, such as via the PJM tariffs and programs. 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 receiving a double payment (LMP plus the savings of foregone energy purchases). On September 17, 2014, the U.S. Court of Appeals for the D.C. Circuit denied FERC's request for review of the May 23, 2014 D.C. Circuit Panel's decision on Order No. 745. On October 20, 2014, and in response to a motion by FERC, the U.S. Court of Appeals for the D.C. Circuit "stayed" issuance of its mandate until December 16, 2014, pending potential appeal by FERC to the U.S. Supreme Court.

On May 23, 2014, FESC, on behalf of FE entities with market-based rate authority, filed a complaint asking FERC to direct PJM to remove all portions of the PJM OATT, which allow or require PJM to include DR in the PJM capacity market, and to invalidate the results of the May 2014 RPM capacity auction on the grounds that the U.S. Court of Appeals for the D.C. Circuit's May 23, 2014 decision required removal of DR from the wholesale capacity markets. FESC filed an amended complaint on September 22, 2014, renewing its request that DR be removed from the May 2014 BRA. On October 22, 2014, PJM filed its answer to the complaint. Various other parties also filed comments on and protests of the amended complaint. The timing of FERC action and the outcome of this proceeding cannot be predicted at this time.

PJM RPM, 2014 Triennial Review

PJM’s tariff obligates it to perform a thorough review of its RPM program every three years. PJM’s usual practice is to work through the stakeholder process to retain a consultant to perform a study. PJM and the stakeholders then review the study results, and incremental changes to the tariff then are filed at FERC. PJM's consultant recently completed the 2014 triennial review and, on September 25, 2014, PJM filed proposed changes to the RPM tariff, purportedly in response to the consultant's study results. Highlights of the September 25, 2014 filing include shifting the VRR curve one percentage point to the right, which, if accepted by FERC, will have the effect of increasing the amount of capacity supply that is procured in the RPM auctions and increasing the clearing price. Another highlight is a proposed change of the index that is used for calculating the generation plant construction costs of the Net Cost-of-New-Entry formula for the future years between triennial reviews. On October 16, 2014, FirstEnergy, as part of a coalition, filed comments supporting the proposal to move the VRR curve, but protesting the proposal to revise the index. This matter is pending before FERC.

Market-Based Rate Authority, Triennial Update

OE, CEI, TE, Penn, JCP&L, ME, PN, MP, WP, PE, 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 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.

TrAIL, Petition for Authorization to Pay Dividends

On October 7, 2014, TrAIL filed a petition with FERC requesting authorization to declare and pay periodic dividends out of paid-in-capital from time to time on an as-needed basis to maintain its capital structure within the range of capital structures approved by FERC for transmission-owning investor-owned utilities. This authorization will provide flexibility to TrAIL to maintain its capital structure without having to issue new long-term debt.

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 RTO 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.

11. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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.

As of September 30, 2014, outstanding guarantees and other assurances aggregated approximately $4.0 billion, consisting of parental guarantees ($672 million), subsidiaries' guarantees ($2,311 million), other guarantees ($330 million) and other assurances ($648 million).

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 FirstEnergy and its subsidiaries have margining provisions that require posting of collateral. Based on the Competitive Energy Segments power portfolio exposures as of September 30, 2014, FES has posted collateral of $197 million and AE Supply has posted no collateral. The Regulated Distribution segment has posted collateral of $3 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 as of September 30, 2014:

Collateral Provisions	FES	AE Supply	Utilities	Total
	(In millions)			
Split Rating (One rating agency's rating below investment grade)	$490	$6	$56	$552
BB+/Ba1 Credit Ratings	$533	$6	$56	$595
Full impact of credit contingent contractual obligations	$784	$68	$94	$946

Excluded from the preceding table is the potential collateral obligations due to affiliate transactions between the Regulated Distribution Segment and Competitive Energy Services Segment. As of September 30, 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 $78 million with affiliated parties.

OTHER COMMITMENTS AND CONTINGENCIES

FE is a guarantor under a syndicated three-year senior secured term loan facility dated October 18, 2011, as amended, that matures 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 FE, 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 guarantees of the obligations of Global Holding under the new facility.

In connection with the 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 as collateral.

FE, FEV and the other two co-owners of Global Holding, Pinesdale LLC, a Gunvor Group, Ltd. subsidiary, and WMB Marketing Ventures, LLC, have agreed, most recently as of August 14, 2013, to use their best efforts to refinance the facility no later than July 20, 2015, on a non-recourse basis so that FE's guaranty can be terminated and/or released. If that refinancing does not occur, FE may require each co-owner to lend to Global Holding, on a pro rata basis, funds sufficient to prepay the facility in full. In lieu of providing such funding, the co-owners, at FE's option, may provide their several guaranties of Global Holding's obligations under the facility. Since January 1, 2013, FE has received a fee for providing its guaranty. The fee is payable semiannually, and accrues at a rate of 5% per annum on the average daily outstanding aggregate commitments under the facility for each semiannual period.

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.

In August 2000, AE received an information request pursuant to section 114(a) of the CAA from the EPA requesting that it provide information and documentation relevant to the operation and maintenance of the following ten coal-fired plants, which collectively include 22 electric generation units: Albright, Armstrong, Fort Martin, Harrison, Hatfield's Ferry, Mitchell, Pleasants, Rivesville, R. Paul Smith and Willow Island to determine compliance with the NSR provisions under the CAA, which can require the installation of additional air emission control equipment when a major modification of an existing facility results in an increase in emissions. In September 2007, AE received 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. On June 29, 2012, January 31, 2013, and March 27, 2013, EPA issued additional CAA section 114 requests for the Harrison coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2007. 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 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. A non-jury trial on liability only was held in September 2010. 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. On March 10, 2014, New York, Connecticut, and Maryland filed an appeal with the U.S. Court of Appeals for the Third Circuit. This decision does not change the status of these plants which remain deactivated.

In July 2008, three complaints representing multiple plaintiffs were filed against FG in the U.S. District Court for the Western District of Pennsylvania seeking damages based on air emissions from the coal-fired Bruce Mansfield Plant. Two of these complaints also seek to enjoin the Bruce Mansfield Plant from operating except in a “safe, responsible, prudent and proper manner.” One complaint was filed on behalf of twenty-one individuals and the other is a class action complaint seeking certification as a class with the eight named plaintiffs as the class representatives. FG believes the claims are without merit and intends to vigorously defend itself against the allegations made in these complaints, but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In January 2009, the EPA issued an NOV to GenOn Energy, Inc. alleging NSR violations at the Keystone, Portland and Shawville coal-fired plants based on “modifications” dating back to the mid-1980s. JCP&L, as the former owner of 16.67% of the Keystone Station, ME, as a former owner and operator of the Portland Station, and PN as former owner and operator of the Shawville Station, are unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In August 2009, the EPA issued a Finding of Violation and NOV alleging violations of the CAA and Ohio regulations, including the PSD, NNSR and Title V regulations, at the Eastlake, Lakeshore, Bay Shore and Ashtabula coal-fired plants. The EPA's NOV alleges equipment replacements during maintenance outages dating back to 1990 triggered the pre-construction permitting requirements under the PSD and NNSR programs. In June 2011, EPA issued another Finding of Violation and NOV alleging violations of the CAA and Ohio regulations, specifically, opacity limitations and requirements to continuously operate opacity monitoring systems at the Eastlake, Lakeshore, Bay Shore and Ashtabula coal-fired plants. FG intends to comply with the CAA and Ohio regulations, but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

National Ambient Air Quality Standards

The EPA's CAIR requires reductions of NOx and SO_2 emissions in two phases (2009/2010 and 2015), ultimately capping SO_2 emissions in affected states to 2.5 million tons annually and NOx emissions to 1.3 million tons annually. In 2008, the U.S. Court of Appeals for the 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 replaces CAIR with a new rule consistent with the Court's decision. In July 2011, the EPA finalized CSAPR, to replace CAIR, requiring reductions of NOx and SO_2 emissions in two phases (2012 and 2014), ultimately capping SO_2 emissions in affected states to 2.4 million tons annually and NOx emissions to 1.2 million tons annually. CSAPR allows trading of NOx and SO_2 emission allowances between power plants located in the same state and interstate trading of NOx and SO_2 emission allowances with some restrictions. On December 30, 2011, CSAPR was stayed by the U.S. Court of Appeals for the D.C. Circuit and was ultimately vacated by the Court on August 21, 2012. The Court has ordered the EPA to continue administration of CAIR until it finalizes a valid replacement for CAIR. On April 29, 2014, the U.S. Supreme Court reversed 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 D.C. Circuit lifted its stay of CSAPR allowing its Phase 1 reductions of NOx and SO_2 emissions to begin in 2015, a 3 year delay from EPA's original rule. CSAPR Phase 2 will also be delayed by 3 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.

Hazardous Air Pollutant Emissions

On December 21, 2011, the EPA finalized the MATS imposing emission limits for mercury, PM, and HCL for all existing and new coal-fired electric generating units effective in April 2015 with averaging of emissions from multiple units located at a single plant. Under the CAA, state permitting authorities can grant an additional compliance year through April 2016, as needed, including instances when necessary to maintain reliability where electric generating units are being closed. On December 28, 2012, the WVDEP granted a conditional 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 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 July 14, 2014, various entities filed a petition seeking further review by the U.S. Supreme Court. Depending on the outcome of further appeals, if any, and how the MATS are ultimately implemented, FirstEnergy's total cost of compliance with MATS is currently estimated to be approximately $370 million (Competitive Energy Services segment of $178 million and Regulated Distribution segment of $192 million), reduced from the previous estimate of $465 million.

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 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 two agreements, FE and FES have agreed to pay liquidated damages for delivery shortfalls for 2014. If FE and FES fail to reach a resolution with applicable counterparties for coal transportation agreements associated with the deactivated plants or unresolved aspects of the transportation agreements and it were ultimately determined that, contrary to their belief, the force majeure provisions or other defenses do not excuse 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. 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.

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 to reduce GHG emissions, such as demand reduction programs, renewable portfolio standards and renewable subsidies have been implemented across the nation. In his 2013 State of the Union address, President Obama called for Congressional action on GHG emissions indicating his administration will take executive action in the event Congress does not pass climate legislation that he supports. To date, Congress has not passed the President's GHG cap and trade proposal. In June 2013, the President's 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. 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.

In September 2009, the EPA finalized a national GHG emissions collection and reporting rule that required the measurement and reporting of GHG emissions commencing in 2010. In December 2009, the EPA released its final "Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act." The EPA's finding concludes that concentrations of several key GHGs constitutes an "endangerment" and may be regulated as "air pollutants" under the CAA. In April 2010, the EPA finalized new GHG standards for model years 2012 to 2016 passenger cars, light-duty trucks and medium-duty passenger vehicles and clarified that GHG regulation under the CAA would not be triggered for electric generating plants and other stationary sources until January 2, 2011, at the earliest. In May 2010, the EPA finalized new thresholds for GHG emissions that define when NSR pre-construction permits would be required including an emissions applicability threshold of 75,000 tons per year of CO_2 equivalents for existing facilities under the CAA's PSD program. On April 13, 2012, the EPA proposed new source performance standards for GHG emissions from newly constructed fossil fuel generating units that are larger than 25 MW, which were ultimately withdrawn. On June 25, 2013, a Presidential memorandum directed the EPA to complete, in a timely fashion, proposed new source performance standards for GHG emissions from newly constructed fossil fuel generating units, starting with re-proposal by September 20, 2013. The memorandum further directed the EPA to propose by June 1, 2014 and complete by June 1, 2015, GHG emission standards for existing fossil fuel electric generating units. On September 20, 2013, the EPA proposed a new source performance standard, 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. On June 2, 2014, the EPA proposed regulations to reduce CO_2 emissions from existing fossil fuel electric generating units that would require each state to develop implementation plans by June 30, 2016, to meet EPA's state specific emission rate goals. EPA's proposal allows states to request a 1-year extension for single-state implementation plans (June 30, 2017) or a 2-year extension for multi-state implementation plans (June 30, 2018). EPA also proposed separate regulations imposing additional CO_2 emission limits on modified and reconstructed fossil fuel electric generating units. On October 15, 2013, the U.S. Supreme Court agreed to review a June 2012 U.S. Court of Appeals for the D.C. Circuit decision upholding the EPA's May 2010 regulations to decide a single narrow question: "Whether EPA permissibly determined that its regulation of greenhouse gas emissions from new motor vehicles triggered permitting requirements under the CAA for stationary sources that emit greenhouse gases?" On June 23, 2014, the U.S. Supreme Court decided that CO_2 or other greenhouse gas 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 greenhouse gas control technologies. Depending on how any final rules are ultimately implemented, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

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.

In 2004, the EPA established new performance standards under Section 316(b) of the CWA for reducing impacts on fish and shellfish from cooling water intake structures at certain existing electric generating plants. The regulations call for reductions in impingement mortality (when aquatic organisms are pinned against screens or other parts of a cooling water intake system) and entrainment (which occurs when aquatic life is drawn into a facility's cooling water system). In 2007, the U.S. Court of Appeals for the Second Circuit invalidated portions of the Section 316(b) performance standards and the EPA has taken the position that until further rulemaking occurs, permitting authorities should continue the existing practice of applying their best professional judgment to minimize impacts on fish and shellfish from cooling water intake structures. In April 2009, the U.S. Supreme Court reversed one significant aspect of the Second Circuit's opinion and decided that Section 316(b) of the CWA authorizes the EPA to compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. On March 28, 2011, the EPA released a new proposed regulation under Section 316(b) of the CWA to reduce fish impingement to a 12% annual average and determine site-specific controls, if any, to reduce entrainment of aquatic life following studies to be provided to permitting authorities. On May 19, 2014, the EPA finalized Section 316(b) regulations requiring cooling water intake structures with an intake velocity greater than 0.5 feet per second to reduce fish impingement to a 12% annual average and determine site-specific controls, if any, to reduce entrainment of aquatic life following studies by cooling water intake structures exceeding 125 million gallons per day. 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 water intake system. Depending on the results of such studies and any final action taken by the states exercising best professional judgment, the future costs of compliance with these standards may require material capital expenditures.

On April 19, 2013, the EPA proposed regulatory changes to the waste water effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423). 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 waste water discharge permits are renewed on a 5-year cycle from 2017 to 2022. Depending on the content of the EPA's final rule, 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 submitted its CWA 303(d) list to the EPA with a recommended sulfate impairment designation for an approximately 68 mile stretch of the Monongahela River north of the West Virginia border. In May 2011, the EPA agreed with PA DEP's recommended sulfate impairment designation which requires the development of a TMDL limit for the river, a process that will take PA DEP approximately five years. Based on the stringency of the TMDL, MP may incur significant costs to reduce sulfate discharges into the Monongahela River if the NPDES permit for the coal-fired Fort Martin plant in West Virginia is required to be modified or renewed to include more stringent effluent limitations for sulfate. However, the Hatfield's Ferry and Mitchell Plants in Pennsylvania that discharge into the Monongahela River were deactivated on October 9, 2013. On April 21, 2014, PA DEP recommended that the sulfate impairment designation for the Monongahela River be removed in its bi-annual water report. A 45-day public comment period ended on June 10, 2014, and PA DEP must obtain EPA approval to remove the sulfate impairment designation which would eliminate the need to develop a TMDL.

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 fossil-fuel combustion residuals, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation.

In December 2009, in an advance notice of public rulemaking, the EPA asserted that the large volumes of CCRs produced by electric utilities pose significant financial risk to the industry. In May 2010, the EPA proposed two options for additional regulation of CCRs, including the option of regulation as a special waste under the EPA's hazardous waste management program which could have a significant impact on the management, beneficial use and disposal of CCRs. On April 19, 2013, the EPA stated it would "align" its proposed CCR regulations with revised waste water discharge effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423) that were proposed on that date. On July 25, 2013, the House of Representatives passed H.R. 221 that would require CCRs to be regulated under Subtitle D of RCRA, as non-hazardous. On January 29, 2014, EPA agreed to take final action by December 19, 2014 on whether or not to pursue the proposed non-hazardous waste option for regulating CCRs in a consent decree entered by a U.S. District Court. Depending on the content of the EPA's final effluent limitations rule, the specifics of any "alignment", whether EPA chooses to pursue the non-hazardous or hazardous waste option and the potential enactment of legislation, the future costs of compliance with such standards may require material capital expenditures.

On July 27, 2012, the PA DEP filed a complaint against FG in the U.S. District Court for the Western District of Pennsylvania with claims under the RCRA and Pennsylvania's Solid Waste Management Act regarding the LBR CCB Impoundment and simultaneously proposed a consent decree between PA DEP and FG to resolve those claims. On December 14, 2012, a modified consent decree that addresses public comments received by PA DEP was entered by the court, requiring FG to conduct monitoring studies and submit a closure plan to the PA DEP, no later than March 31, 2013, and discontinue disposal to LBR as currently permitted by December 31, 2016. The modified consent decree also required payment of civil penalties of $800,000 to resolve claims under the Solid Waste Management Act. On December 20, 2012, the Environmental Integrity Project and others served FG with a citizen suit notice alleging CWA and PA Clean Streams Law Violations at LBR. On February 1, 2013, FG submitted a feasibility study analyzing various technical issues relevant to the closure of LBR. On March 28, 2013, FG submitted to the PA DEP a Closure Plan Major Permit Modification Application which provides for placing a final cap over LBR that would require 15 years to fully implement following the closure of LBR. The estimated cost for the proposed closure plan is $234 million, including environmental and other post closure costs. On October 3, 2013, the PA DEP issued a technical deficiency letter citing four main deficiencies with the closure plan: (1) seeking to accelerate the 15 year period proposed by FG for closure activities to complete closure in 9 years by commencing closure activities prior to 2017 as proposed by FG; (2) seeking to extend bond closure and post closure activities beyond the 45 years proposed by FG; (3) seeking active dewatering of the CCBs in areas where there are seeps impacted by the Impoundment; and (4) seeking an abatement plan for groundwater impacted by arsenic. FG responded to the PA DEP on December 3, 2013, and as a result of the closure plan, FG increased its ARO for LBR by $163 million in 2013. On April 3, 2014, PA DEP issued a 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 CCBs, 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 CCBs following December 31, 2016, and on January 23, 2013, announced a plan for beneficial use of its CCBs for mine reclamation in LaBelle, Pennsylvania. In June 2013, a complaint filed in the U.S. District Court for the Western District of Pennsylvania, against the owner and operator of that mine, 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.

Lawsuits initially filed on October 10, 2013 and December 5, 2013, are pending against FG involving approximately 61 individuals in the U.S. District Court for the Northern District of West Virginia and approximately 26 individuals (16 of which have settled their claims) in the U.S. District Court for the Western District of Pennsylvania seeking damages for alleged property damage, bodily injury and emotional distress related to the LBR CCB 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.

FirstEnergy's future cost of compliance with any CCR regulations that may be promulgated could be substantial and would depend, in part, on the regulatory action taken by the EPA and implementation by the EPA or the states. Compliance with those regulations could have an adverse impact on FirstEnergy's results of operations and financial condition.

Certain of FirstEnergy's utilities have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the CERCLA. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all potentially responsible parties for a particular site may be liable on a joint and several basis. Environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of September 30, 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 $117 million have been accrued through September 30, 2014. Included in the total are accrued liabilities of approximately $82 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 September 30, 2014, FirstEnergy had approximately $2.4 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 NDT fluctuate based on market conditions. If the value of the trusts decline by a material amount, FirstEnergy's obligation to fund the trusts may increase. Disruptions in the capital markets and their effects on particular businesses and the economy could also affect the values of the NDT. 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. A NRC ASLB granted a hearing on the Davis-Besse license renewal application to a group of Intervenors. On July 9, 2012, the Intervenors proposed a contention on the environmental impacts of spent fuel storage in the Davis-Besse license renewal proceeding. In an order dated August 7, 2012, the Commissioners stated that they would not issue final licensing decisions until they had appropriately addressed the challenges to the NRC Waste Confidence Decision and Temporary Storage Rule and all pending contentions on this topic should be held in abeyance. On August 26, 2014, the Commissioners issued an order, which lifted the suspension on issuing final licensing decisions, based on a final rule on waste confidence that was approved by the NRC on that date. On October 8, 2014, the ASLB dismissed the proposed contention on the environmental impacts of the temporary storage and ultimate disposal of spent nuclear fuel. On September 29, 2014, the Intervenors filed a new 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 recent rulemaking on waste confidence 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. The shield building is a 2 1/2-foot thick reinforced concrete structure that provides biological shielding, protection from natural phenomena including wind and tornadoes and additional shielding in the event of an accident. 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 admit a new contention based on FENOC's plans to manage the subsurface laminar cracking in the Davis-Besse shield building. On October 3, 2014, FENOC and the NRC Staff filed their opposition to the admission of this new contention.

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. Anker WV entered into a long term CSA with AE Supply and MP for the supply of coal to the Harrison generating facility. Prior to the time of trial, ICG was dismissed as a defendant by the Court. As a result of defendants' past and continued failure to supply the contracted coal, AE Supply and MP have incurred and will continue to incur significant additional costs for purchasing replacement coal. A non-jury trial was held from January 10, 2011 through February 1, 2011. At trial, AE Supply and MP presented evidence that they incurred in excess of $80 million in damages for replacement coal purchased through the end of 2010 and will incur additional damages in excess of $150 million for future shortfalls. Defendants primarily claimed their performance was excused by the force majeure clause in the CSA and presented evidence at trial that they could not provide the contracted yearly tonnage amounts. On May 2, 2011, the court entered a verdict in favor of AE Supply and MP for $104 million ($90 million in future damages and $14 million for past damages/interest). On August 25, 2011, the Allegheny County Court denied all Motions for Post-Trial relief and the May 2, 2011 verdict became final. On August 26, 2011, the defendants posted bond and filed a Notice of Appeal with the Superior Court. On August 13, 2012, the Superior Court affirmed the $14 million past damages award but vacated the $90 million future damages award. While the Superior Court found that defendants still owed future damages, it remanded the calculation of those damages back to the trial court. On August 27, 2012, AE Supply and MP filed an Application for Reargument En Banc with the Superior Court, which was denied on October 19, 2012. AE Supply and MP filed a Petition for Allowance of Appeal with the Pennsylvania Supreme Court on November 19, 2012. On July 2, 2013, the Petition for Allowance of Appeal was denied and in the second quarter of 2013 the final past damage award of $15.5 million (including interest) was recognized.

The case was sent back to the trial court to recalculate the future damages only, and a multi-day hearing was held beginning May 13, 2014. A ruling is expected in the fourth quarter of 2014. In a related proceeding before the same court, ICG is appealing a ruling by the court that prohibited their reliance on a price re-opener clause to limit future damages.

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 10, 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.

12. SUPPLEMENTAL GUARANTOR INFORMATION

In 2007, FG completed a sale and leaseback transaction for a 93.83% undivided interest in Bruce Mansfield Unit 1. FES has fully and unconditionally and irrevocably guaranteed all of FG's obligations under each of the leases. The related lessor notes and pass through certificates are not guaranteed by FES or FG, but the notes are secured by, among other things, each lessor trust's undivided interest in Unit 1, rights and interests under the applicable lease and rights and interests under other related agreements, including FES' lease guaranty. This transaction is classified as an operating lease for FES and FirstEnergy and as a financing lease for FG.

The Condensed Consolidating Statements of Income (Loss) and Comprehensive Income (Loss) for the three and nine months ended September 30, 2014 and 2013, Condensed Consolidating Balance Sheets as of September 30, 2014 and December 31, 2013, and Condensed Consolidating Statements of Cash Flows for the nine months ended September 30, 2014 and 2013, for FES (parent and guarantor), FG and NG (non-guarantor) are presented below. These statements are provided as FES fully and unconditionally guarantees outstanding registered securities of FG as well as FG's obligations under the facility lease for the Bruce Mansfield sale and leaseback that underlie outstanding registered pass-through trust certificates. Investments in wholly owned subsidiaries are accounted for by FES using the equity method. Results of operations for FG and NG are, therefore, reflected in FES' investment accounts and earnings as if operating lease treatment was achieved. The principal elimination entries eliminate investments in subsidiaries and intercompany balances and transactions and the entries required to reflect operating lease treatment associated with the 2007 Bruce Mansfield Unit 1 sale and leaseback transaction.

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

For the Three Months Ended September 30, 2014	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
REVENUES	$1,481	$477	$592	$(1,029)	$1,521
OPERATING EXPENSES:					
Fuel	—	216	54	—	270
Purchased power from affiliates	1,026	—	64	(1,026)	64
Purchased power from non-affiliates	627	—	—	—	627
Other operating expenses	178	59	106	13	356
Provision for depreciation	2	30	52	(1)	83
General taxes	17	7	7	—	31
Total operating expenses	1,850	312	283	(1,014)	1,431
OPERATING INCOME (LOSS)	(369)	165	309	(15)	90
OTHER INCOME (EXPENSE):					
Loss on debt redemptions	—	—	(1)	—	(1)
Investment income	2	3	13	(5)	13
Miscellaneous income (expense), including net income from equity investees	289	(2)	—	(286)	1
Interest expense — affiliates	(3)	(2)	—	4	(1)
Interest expense — other	(13)	(26)	(14)	16	(37)
Capitalized interest	—	2	5	—	7
Total other income (expense)	275	(25)	3	(271)	(18)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES (BENEFITS)	(94)	140	312	(286)	72
INCOME TAXES (BENEFITS)	(138)	49	117	—	28
INCOME FROM CONTINUING OPERATIONS	44	91	195	(286)	44
Discontinued operations (Note 14)	—	—	—	—	—
NET INCOME	$44	$91	$195	$(286)	$44
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$44	$91	$195	$(286)	$44

OTHER COMPREHENSIVE LOSS:					
Pensions and OPEB prior service costs	(4)	(4)	—	4	(4)
Amortized gain on derivative hedges	(2)	—	—	—	(2)
Change in unrealized gain on available-for-sale securities	(9)	—	(9)	9	(9)
Other comprehensive loss	(15)	(4)	(9)	13	(15)
Income tax benefits on other comprehensive loss	(6)	(2)	(3)	5	(6)
Other comprehensive loss, net of tax	(9)	(2)	(6)	8	(9)
COMPREHENSIVE INCOME	$35	$89	$189	$(278)	$35

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

For the Nine Months Ended September 30, 2014	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME (LOSS)					
REVENUES	$4,690	$1,297	$1,391	$(2,576)	$4,802
OPERATING EXPENSES:					
Fuel	—	776	147	—	923
Purchased power from affiliates	2,573	—	203	(2,573)	203
Purchased power from non-affiliates	2,270	4	—	—	2,274
Other operating expenses	648	200	391	37	1,276
Provision for depreciation	6	89	143	(2)	236
General taxes	56	24	19	—	99
Total operating expenses	5,553	1,093	903	(2,538)	5,011
OPERATING INCOME (LOSS)	(863)	204	488	(38)	(209)
OTHER INCOME (EXPENSE):					
Loss on debt redemptions	(3)	(1)	(2)	—	(6)
Investment income	5	6	57	(11)	57
Miscellaneous income, including net income from equity investees	551	1	—	(547)	5
Interest expense — affiliates	(8)	(5)	(2)	10	(5)
Interest expense — other	(41)	(75)	(40)	46	(110)
Capitalized interest	—	3	24	—	27
Total other income (expense)	504	(71)	37	(502)	(32)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES (BENEFITS)	(359)	133	525	(540)	(241)
INCOME TAXES (BENEFITS)	(327)	41	188	3	(95)
INCOME (LOSS) FROM CONTINUING OPERATIONS	(32)	92	337	(543)	(146)
Discontinued operations (net of income taxes of $70) (Note 14)	—	116	—	—	116
NET INCOME (LOSS)	$(32)	$208	$337	$(543)	$(30)
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)					

NET INCOME (LOSS)	$(32)	$208	$337	$(543)	$(30)
OTHER COMPREHENSIVE INCOME (LOSS):					
Pensions and OPEB prior service costs	(14)	(13)	—	13	(14)
Amortized gain on derivative hedges	(7)	—	—	—	(7)
Change in unrealized gain on available-for-sale securities	35	—	35	(35)	35
Other comprehensive income (loss)	14	(13)	35	(22)	14
Income taxes (benefits) on other comprehensive income (loss)	5	(5)	13	(8)	5
Other comprehensive income (loss), net of tax	9	(8)	22	(14)	9
COMPREHENSIVE INCOME (LOSS)	$(23)	$200	$359	$(557)	$(21)

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

For the Three Months Ended September 30, 2013	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME					
REVENUES	$1,654	$528	$440	$(943)	$1,679
OPERATING EXPENSES:					
Fuel	—	249	55	—	304
Purchased power from affiliates	1,009	—	65	(942)	132
Purchased power from non-affiliates	720	4	—	—	724
Other operating expenses	147	65	114	13	339
Provision for depreciation	1	33	46	—	80
General taxes	21	9	5	—	35
Total operating expenses	1,898	360	285	(929)	1,614
OPERATING INCOME (LOSS)	(244)	168	155	(14)	65
OTHER INCOME (EXPENSE):					
Investment income (loss)	2	—	(1)	(4)	(3)
Miscellaneous income, including net income from equity investees	180	19	—	(178)	21
Interest expense — affiliates	(3)	(2)	(1)	5	(1)
Interest expense — other	(13)	(24)	(13)	15	(35)
Capitalized interest	—	1	8	—	9
Total other income (expense)	166	(6)	(7)	(162)	(9)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES (BENEFITS)	(78)	162	148	(176)	56
INCOME TAXES (BENEFITS)	(118)	111	28	2	23
INCOME FROM CONTINUING OPERATIONS	40	51	120	(178)	33
Discontinued operations (net of income taxes of $5) (Note 14)	—	7	—	—	7
NET INCOME	$40	$58	$120	$(178)	$40
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$40	$58	$120	$(178)	$40

OTHER COMPREHENSIVE INCOME (LOSS):					
Pensions and OPEB prior service costs	(5)	(5)	—	5	(5)
Amortized gain on derivative hedges	(1)	—	—	—	(1)
Change in unrealized gain on available for sale securities	5	—	5	(5)	5
Other comprehensive income (loss)	(1)	(5)	5	—	(1)
Income taxes (benefits) on other comprehensive income (loss)	(1)	(2)	3	(1)	(1)
Other comprehensive income (loss), net of tax	—	(3)	2	1	—
COMPREHENSIVE INCOME	$40	$55	$122	$(177)	$40

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

For the Nine Months Ended September 30, 2013	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME (LOSS)					
REVENUES	$4,575	$1,612	$1,337	$(2,869)	$4,655
OPERATING EXPENSES:					
Fuel	—	782	154	—	936
Purchased power from affiliates	3,072	—	197	(2,868)	401
Purchased power from non-affiliates	1,749	6	—	—	1,755
Other operating expenses	484	208	376	37	1,105
Provision for depreciation	4	96	134	(3)	231
General taxes	60	28	18	—	106
Total operating expenses	5,369	1,120	879	(2,834)	4,534
OPERATING INCOME (LOSS)	(794)	492	458	(35)	121
OTHER INCOME (EXPENSE):					
Loss on debt redemptions	(103)	—	—	—	(103)
Investment income	4	—	3	(11)	(4)
Miscellaneous income, including net income from equity investees	543	23	—	(537)	29
Interest expense — affiliates	(10)	(4)	(5)	12	(7)
Interest expense — other	(50)	(79)	(42)	45	(126)
Capitalized interest	1	1	26	—	28
Total other income (expense)	385	(59)	(18)	(491)	(183)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES (BENEFITS)	(409)	433	440	(526)	(62)
INCOME TAXES (BENEFITS)	(380)	215	138	8	(19)
INCOME (LOSS) FROM CONTINUING OPERATIONS	(29)	218	302	(534)	(43)
Discontinued operations (net of income taxes of $8) Note (14)	—	14	—	—	14
NET INCOME (LOSS)	$(29)	$232	$302	$(534)	$(29)
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)					

NET INCOME (LOSS)	$(29)	$232	$302	$(534)	$(29)
OTHER COMPREHENSIVE INCOME (LOSS):					
Pensions and OPEB prior service costs	(16)	(15)	—	15	(16)
Amortized gain on derivative hedges	(3)	—	—	—	(3)
Change in unrealized gain on available-for-sale securities	2	—	2	(2)	2
Other comprehensive income (loss)	(17)	(15)	2	13	(17)
Income taxes (benefits) on other comprehensive income (loss)	(7)	(6)	1	5	(7)
Other comprehensive income (loss), net of tax	(10)	(9)	1	8	(10)
COMPREHENSIVE INCOME (LOSS)	$(39)	$223	$303	$(526)	$(39)

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FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

As of September 30, 2014	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$—	$2	$—	$—	$2
Receivables-					
Customers	445	—	—	—	445
Affiliated companies	408	339	538	(797)	488
Other	61	21	32	—	114
Notes receivable from affiliated companies	408	769	364	(1,327)	214
Materials and supplies	59	194	218	—	471
Derivatives	168	—	—	—	168
Collateral	218	—	—	—	218
Prepayments and other	43	54	1	—	98
	1,810	1,379	1,153	(2,124)	2,218
PROPERTY, PLANT AND EQUIPMENT:					
In service	128	6,195	7,805	(383)	13,745
Less — Accumulated provision for depreciation	34	2,032	3,211	(190)	5,087
	94	4,163	4,594	(193)	8,658
Construction work in progress	6	146	536	—	688
	100	4,309	5,130	(193)	9,346
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,381	—	1,381
Investment in affiliated companies	6,345	—	—	(6,345)	—
Other	—	11	—	—	11
	6,345	11	1,381	(6,345)	1,392
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	307	39	—	(346)	—
Customer intangibles	82	—	—	—	82
Goodwill	23	—	—	—	23
Property taxes	—	4	5	—	9
Unamortized sale and leaseback costs	—	—	—	210	210
Derivatives	42	—	—	—	42
Other	40	278	3	(214)	107
	494	321	8	(350)	473
	$8,749	$6,020	$7,672	$(9,012)	$13,429
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$18	$163	$377	$(23)	$535
Short-term borrowings-					
Affiliated companies	946	381	—	(1,327)	—
Other	12	9	—	—	21

Accounts payable-					
Affiliated companies	704	115	338	(704)	453
Other	66	112	—	—	178
Accrued taxes	251	27	30	(141)	167
Derivatives	166	—	—	—	166
Other	52	67	16	35	170
	2,215	874	761	(2,160)	1,690
CAPITALIZATION:					
Total equity	5,772	2,491	3,855	(6,315)	5,803
Long-term debt and other long-term obligations	694	2,229	881	(1,173)	2,631
	6,466	4,720	4,736	(7,488)	8,434
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	833	833
Accumulated deferred income taxes	—	—	937	(196)	741
Asset retirement obligations	—	189	870	—	1,059
Retirement benefits	23	175	—	(1)	197
Derivatives	20	—	—	—	20
Other	25	62	368	—	455
	68	426	2,175	636	3,305
	$8,749	$6,020	$7,672	$(9,012)	$13,429

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

As of December 31, 2013	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$—	$2	$—	$—	$2
Receivables-					
Customers	539	—	—	—	539
Affiliated companies	938	787	227	(916)	1,036
Other	52	12	17	—	81
Notes receivable from affiliated companies	203	23	683	(909)	—
Materials and supplies	76	159	213	—	448
Derivatives	165	—	—	—	165
Collateral	136	—	—	—	136
Prepayments and other	52	50	7	—	109
	2,161	1,033	1,147	(1,825)	2,516
PROPERTY, PLANT AND EQUIPMENT:					
In service	104	6,105	6,645	(382)	12,472
Less — Accumulated provision for depreciation	28	1,953	2,962	(188)	4,755
	76	4,152	3,683	(194)	7,717
Construction work in progress	23	148	1,137	—	1,308
	99	4,300	4,820	(194)	9,025
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,276	—	1,276
Investment in affiliated companies	5,801	—	—	(5,801)	—
Other	—	11	—	—	11
	5,801	11	1,276	(5,801)	1,287
ASSETS HELD FOR SALE	—	122	—	—	122
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	—	131	—	(131)	—
Customer intangibles	95	—	—	—	95
Goodwill	23	—	—	—	23
Property taxes	—	15	26	—	41
Unamortized sale and leaseback costs	—	—	—	168	168
Derivatives	53	—	—	—	53
Other	81	228	18	(155)	172
	252	374	44	(118)	552
	$8,313	$5,840	$7,287	$(7,938)	$13,502
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$1	$367	$547	$(23)	$892
Short-term borrowings-					

Affiliated companies	977	212	151	(909)	431
Other	—	4	—	—	4
Accounts payable-					
Affiliated companies	741	400	362	(738)	765
Other	94	196	—	—	290
Accrued taxes	204	23	23	(184)	66
Derivatives	110	—	—	—	110
Other	70	63	18	46	197
	2,197	1,265	1,101	(1,808)	2,755
CAPITALIZATION:					
Total equity	5,312	2,283	3,493	(5,776)	5,312
Long-term debt and other long-term obligations	712	1,860	742	(1,184)	2,130
	6,024	4,143	4,235	(6,960)	7,442
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	858	858
Accumulated deferred income taxes	32	—	736	(27)	741
Asset retirement obligations	—	187	828	—	1,015
Retirement benefits	22	163	—	—	185
Derivatives	14	—	—	—	14
Other	24	82	387	(1)	492
	92	432	1,951	830	3,305
	$8,313	$5,840	$7,287	$(7,938)	$13,502

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

For the Nine Months Ended September 30, 2014	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$(269)	$197	$511	$(11)	$428
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	—	431	447	—	878
Short-term borrowings, net	—	173	—	(173)	—
Equity contribution from parent	500	—	—	—	500
Redemptions and Repayments-					
Long-term debt	—	(258)	(502)	11	(749)
Short-term borrowings, net	(20)	—	(150)	(244)	(414)
Other	—	(10)	(4)	—	(14)
Net cash provided from (used for) financing activities	480	336	(209)	(406)	201
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(6)	(99)	(481)	—	(586)
Nuclear fuel	—	—	(98)	—	(98)
Proceeds from asset sales	—	307	—	—	307
Sales of investment securities held in trusts	—	—	890	—	890
Purchases of investment securities held in trusts	—	—	(933)	—	(933)
Loans to affiliated companies, net	(205)	(746)	320	417	(214)
Other	—	5	—	—	5
Net cash used for investing activities	(211)	(533)	(302)	417	(629)
Net change in cash and cash equivalents	—	—	—	—	—
Cash and cash equivalents at beginning of period	—	2	—	—	2
Cash and cash equivalents at end of period	$—	$2	$—	$—	$2

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

For the Nine Months Ended September 30, 2013	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$(1,018)	$712	$705	$(10)	$389
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Short-term borrowings, net	338	—	—	(338)	—
Equity contribution from parent	1,500	—	—	—	1,500
Redemptions and Repayments-					
Long-term debt	(769)	(352)	(68)	10	(1,179)
Short-term borrowings, net	—	(32)	—	32	—
Tender premiums	(67)	—	—	—	(67)
Other	(3)	(4)	—	—	(7)
Net cash provided from (used for) financing activities	999	(388)	(68)	(296)	247
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(9)	(192)	(276)	—	(477)
Nuclear fuel	—	—	(159)	—	(159)
Proceeds from asset sales	—	21	—	—	21
Sales of investment securities held in trusts	—	—	650	—	650
Purchases of investment securities held in trusts	—	—	(694)	—	(694)
Loans to affiliated companies, net	28	(156)	(156)	306	22
Other	—	2	(2)	—	—
Net cash provided from (used for) investing activities	19	(325)	(637)	306	(637)
Net change in cash and cash equivalents	—	(1)	—	—	(1)
Cash and cash equivalents at beginning of period	—	3	—	—	3
Cash and cash equivalents at end of period	$—	$2	$—	$—	$2

13. SEGMENT INFORMATION

FirstEnergy continues to have three reportable operating segments - Regulated Distribution, Regulated Transmission and Competitive Energy Services. The external reporting is consistent with the internal financial reporting used by FirstEnergy’s Chief Executive Officer (its chief operating decision maker) to regularly assess the performance of the business and allocate resources.

Financial information for each of FirstEnergy’s reportable segments is presented in the tables below. FES does not have separate reportable operating segments.

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 in West Virginia and New Jersey that MP and JCP&L, respectively, own or contractually control. Its results reflect the commodity costs of securing electric generation and the deferral and amortization of certain fuel costs. This business segment currently controls approximately 3,790 MWs of generation capacity.

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 derived from transmission services provided pursuant to the PJM open access transmission tariff to LSEs. Its results also reflect the net transmission expenses related to the delivery of electricity on FirstEnergy's transmission facilities.

The Competitive Energy Services segment, through FES and AE Supply, supplies electricity to end-use customers through retail and wholesale arrangements, including competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, and the provision of partial POLR and default service for some utilities in Ohio, Pennsylvania and Maryland, including the Utilities. This business segment currently controls approximately 14,000 MWs of capacity, including 885 MWs of capacity scheduled to be deactivated by April 2015. This segment also purchases electricity to meet sales obligations. The segment’s net income is primarily derived from electric generation sales less the related costs of electricity generation, including fuel, purchased power and net transmission (including congestion) and ancillary costs charged by PJM to deliver energy to the segment’s customers.

The Competitive Energy Services segment is taking action to reduce its exposure to weather-sensitive loads, including maintaining competitive generation in excess of committed sales, eliminating load obligations that do not adequately cover risk premiums, pursuing more certain revenue streams, and modifying its hedging strategy to optimize risk management and market upside opportunities. As part of this, the Competitive Energy Services segment has eliminated future selling efforts in certain sales channels, such as mass market, medium commercial-industrial and select large commercial-industrial, 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 as was experienced in the first quarter of 2014. Going forward, the Competitive Energy Services segment will target 65 to 75 million MWHs of sales with a 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, 10 to 20 million MWHs in block wholesale sales and 10 to 20 million MWHs of spot wholesale sales. Support for current customers in the channels to be exited will remain through their respective contract terms.

The Other/Corporate Segment contains corporate items and other businesses that are below the quantifiable threshold for separate disclosure as a reportable segment. Reconciling adjustments primarily consist of elimination of intersegment transactions.

Segment Financial Information

Three Months Ended	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other/Corporate	Reconciling Adjustments	Consolidated
	(In millions)					
September 30, 2014						
External revenues	$2,357	$197	$1,406	$(39)	$(33)	$3,888
Internal revenues	—	—	193	—	(193)	—
Total revenues	2,357	197	1,599	(39)	(226)	3,888
Depreciation, amortization and deferrals	198	36	100	11	(2)	343
Investment income	14	—	11	4	(13)	16
Interest expense	147	35	49	46	(2)	275
Income taxes (benefits)	124	30	36	(42)	4	152
Income (loss) from continuing operations	227	55	66	(15)	—	333
Discontinued operations, net of tax	—	—	—	—	—	—
Net income (loss)	227	55	66	(15)	—	333
Property additions	271	279	97	17	—	664
September 30, 2013						
External revenues	$2,337	$189	$1,570	$(31)	$(33)	$4,032
Internal revenues	—	—	196	—	(196)	—
Total revenues	2,337	189	1,766	(31)	(229)	4,032
Depreciation, amortization and deferrals	460	31	125	12	—	628
Investment income (loss)	14	—	(2)	3	(10)	5
Interest expense	134	23	53	47	—	257
Income taxes (benefits)	50	32	47	(44)	(8)	77
Income (loss) from continuing operations	85	54	68	(10)	12	209
Discontinued operations, net of tax	—	—	9	—	—	9
Net income (loss)	85	54	77	(10)	12	218
Property additions	261	105	162	20	—	548
Nine Months Ended						
September 30, 2014						
External revenues	$6,972	$570	$4,239	$(110)	$(105)	$11,566
Internal revenues	—	—	624	—	(624)	—
Total revenues	6,972	570	4,863	(110)	(729)	11,566
Depreciation, amortization and deferrals	509	102	287	35	(2)	931
Investment income	44	—	46	9	(32)	67
Interest expense	445	90	143	128	(4)	802

Income taxes (benefits)	326	92	(102)	(98)	8	226
Income (loss) from continuing operations	599	169	(177)	(73)	1	519
Discontinued operations, net of tax	—	—	86	—	—	86
Net income (loss)	599	169	(91)	(73)	1	605
Total assets	27,774	6,102	16,839	509	—	51,224
Total goodwill	5,092	526	800	—	—	6,418
Property additions	780	980	655	58	—	2,473
September 30, 2013						
External revenues	$6,584	$ 544	$4,352	$ (89)	$(132)	$11,259
Internal revenues	—	—	588	—	(588)	—
Total revenues	6,584	544	4,940	(89)	(720)	11,259
Depreciation, amortization and deferrals	882	91	347	32	—	1,352
Investment income (loss)	41	—	(8)	6	(31)	8
Interest expense	404	68	187	112	—	771
Income taxes (benefits)	284	93	(189)	(55)	(4)	129
Income (loss) from continuing operations	474	156	(317)	(92)	12	233
Discontinued operations, net of tax	—	—	17	—	—	17
Net income (loss)	474	156	(300)	(92)	12	250
Total assets	27,030	5,038	17,809	591	—	50,468
Total goodwill	5,025	526	867	—	—	6,418
Property additions	980	291	630	59	—	1,960

14. DISCONTINUED OPERATIONS

On September 4, 2013, certain of FirstEnergy subsidiaries applied for authorization from the FERC to sell eleven hydroelectric power stations in Pennsylvania, Virginia and West Virginia to subsidiaries of Harbor Hydro, a subsidiary of LS Power. The asset purchase agreement was entered into on August 23, 2013, and amended and restated as of September 4, 2013. On February 12, 2014, the sale of the hydroelectric power plants to LS Power closed for approximately $394 million (FES - $307 million). The carrying value of the assets sold was $235 million (FES - $122 million), including goodwill of $29 million (FES - $1 million) which was allocated to the hydroelectric plants to be sold.

Pre-tax income for the hydroelectric facilities of $155 million (FES - $186 million) for the nine months ended September 30, 2014, and $12 million and $26 million (FES - $12 million and $22 million) for the three and nine months ended September 30, 2013, respectively, were included in discontinued operations in the Consolidated Statement of Income (Loss). Included in income from discontinued operations in the nine months ended September 30, 2014, was a pre-tax gain on the sale of assets of $142 million (FES - $177 million). Revenues for the hydroelectric facilities of $5 million (FES - $5 million) for the nine months ended September 30, 2014 and $11 million and $24 million (FES - $10 million and $22 million) for the three and nine months ended September 30, 2013, respectively, were included in discontinued operations in the Consolidated Statement of Income.

15. IMPAIRMENT OF LONG-LIVED ASSETS

On July 8, 2013, officers of FirstEnergy and AE Supply committed to deactivating the following generating units by October 9, 2013:

Generating Units	MW Capacity	Location
Hatfield's Ferry, Units 1-3	1,710	Masontown, Pennsylvania
Mitchell, Units 2-3	370	Courtney, Pennsylvania

As a result of this decision, in the second quarter of 2013, FirstEnergy recorded a pre-tax impairment of approximately $473 million to continuing operations, which also includes pre-tax impairments of $13 million related to excessive inventory at these facilities. The impairment charge is included within the results of the Competitive Energy Services segment. On October 9, 2013, Hatfield's Ferry Units 1-3 and Mitchell Units 2-3 were deactivated.

Item 2. Management's Discussion and Analysis of Registrant and Subsidiaries

FIRSTENERGY CORP.

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

OVERVIEW

Net income in the third quarter of 2014 was $333 million, or basic and diluted earnings of $0.79 per share, compared with net income of $218 million, or basic and diluted earnings of $0.52 per share of common stock in the third quarter of 2013. Net income (loss) and changes by segment are summarized below:

	Three Months Ended September 30			Nine Months Ended September 30		
	2014	2013	Increase (Decrease)	2014	2013	Increase
	(In millions, except per share)					
Net Income (Loss) By Segment:						
Regulated Distribution	$227	$85	$142	$599	$474	$125
Regulated Transmission	55	54	1	169	156	13
Competitive Energy Services	66	77	(11)	(91)	(300)	209
Other and reconciling adjustments	(15)	2	(17)	(72)	(80)	8
FirstEnergy Corp.	$333	$218	$115	$605	$250	$355
Earnings per share - Basic	$0.79	$0.52	$0.27	$1.44	$0.60	$0.84
Earnings per share - Diluted	$0.79	$0.52	$0.27	$1.44	$0.60	$0.84

Three months ended September 30, 2014 compared to the three months ended September 30, 2013

The Regulated Distribution segment's earnings were primarily impacted by the following:

- Lower deliveries to residential and commercial customers primarily reflecting decreased weather-related usage from cooling degree days that were 15% below last year. Sales to the industrial sector increased more than 3% primarily related to shale gas, steel and petroleum customers.
- Increased regulated generation earnings primarily associated with the Harrison/Pleasants asset transfer in October of 2013. Currently a return on and of Harrison Plant costs are included as a temporary surcharge billed to all retail customers.
- Lower Regulatory charges of $253 million (pre-tax) primarily resulting from a 2013 regulatory asset impairment associated with deferred marginal transmission losses at ME and PN.

The Regulated Transmission segment's earnings were primarily impacted by the following:

- Higher ATSI revenues reflecting incremental cost of service and rate base recovery resulting from its annual rate filing effective June 2014.
- Increased operating and maintenance expenses, property taxes and depreciation associated with a higher asset base.

The Competitive Energy Services segment's earnings were primarily impacted by the following:

- Reduced revenues resulting from lower customer counts as the segment aligns its sales portfolio to more effectively hedge its generation, partially offset by higher capacity revenues resulting from higher capacity rates.
- Higher capacity expenses associated with its retail sales obligations resulting from higher capacity rates.
- Lower expenses for fuel, depreciation and operations primarily as a result of plant deactivations and the Harrison/Pleasants asset transfer.

- Other items impacting the Competitive Energy Services segment's earnings include the following pre-tax charges and gains:
- Losses related to commodity mark-to-market adjustments were $20 million in the third quarter of 2014. There were mark-to-market gains of $3 million in the third quarter of 2013.
- Impairments on securities held in NDT were $6 million in the third quarter of 2014 compared to $21 million in the third quarter of 2013.

The Other segment's results of operations were impacted primarily by lower tax benefits and a gain on debt redemptions recognized in the third quarter of 2013.

Executive Summary

FirstEnergy holds a large and diverse mix of assets, 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 a result of the challenging environment in the Competitive Energy Services segment, FirstEnergy has redirected its growth strategy to pursue more predictable and sustainable long-term growth opportunities in its regulated businesses.

FirstEnergy's strategy is to focus on growth through 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 expenditure forecast for 2014 is approximately $1.35 billion. As a result of these investments, Regulated Transmission's earnings are expected to grow modestly over the next two years and then accelerate as the investments are fully recognized in rates. In total, FirstEnergy has identified at least $7 billion in transmission investment opportunities across the 24,000 mile transmission system, making this a continuing platform for growth in the years beyond 2017.

In the territory served by FirstEnergy’s Regulated Distribution segment, the economy has begun to recover from the recession, but there continues to be weak demand for electricity as evidenced by flat distribution sales volumes over the last three years. However, FirstEnergy has experienced steady growth over the last several quarters particularly in the industrial and commercial sectors when adjusted for the impacts of weather. The location of the Marcellus and Utica shale gas region has provided a source of that growth and provides optimism for growth over the long term. More than 400 MW of new industrial demand associated with shale gas activity is expected to come online in FirstEnergy's region by the end of 2014, with more than 1,100 MW of additional planned expansion at customer facilities through 2019. These projects alone are expected to result in more industrial growth over the next two years, and a robust pipeline of mid-stream projects represent further opportunities for additional growth, as well as the potential for growth in the residential class.

FirstEnergy is also pursuing regulatory initiatives across its utility footprint, including, as further described below, a rate case application in West Virginia filed in April 2014, rate case applications in Pennsylvania filed in August 2014, and an ESP IV filing in Ohio filed in August 2014, as well as the current rate proceeding in New Jersey. Also, on October 31, 2014, ATSI filed a proposal with FERC to change the structure of its formula rate. The proposed change requests a 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. ATSI has requested FERC approval of the proposal with an effective date of January 1, 2015. FirstEnergy expects that FERC will issue an initial ruling by the end of 2014.

Additionally, FirstEnergy continues to focus on maintaining the value of its competitive business, which has been challenged over the last several years by prolonged weak demand for power, low capacity payments and energy prices. FirstEnergy has reduced the size and shifted the mix of its generating assets, as well as reduced operating expenses and capital expenditures. As a result, the remaining competitive fleet is more cost-effective, efficient and environmentally sound. In addition, FirstEnergy is taking action to reduce its exposure to weather-sensitive loads, including maintaining competitive generation in excess of committed sales, eliminate load obligations that do not adequately cover risk premiums, pursue more certain revenue streams, and modify its hedging strategy to optimize risk management and market upside opportunities. As part of this, the Competitive Energy Services segment has eliminated future selling efforts in certain sales channels, such as mass market, medium commercial-industrial and select large commercial-industrial, 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 as was experienced in the first quarter of 2014. Going forward, the Competitive Energy Services segment expects to target a sales portfolio 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, 10 to 20 million in block wholesale sales and 10 to 20 million of spot wholesale sales. Support for current customers in the channels to be exited will remain through their respective contract terms.

While it cannot predict if or when a power price recovery may occur, FirstEnergy believes it has taken appropriate action over the last two years to reposition this business for such a recovery.

In alignment with FirstEnergy’s strategy to focus on growing the Regulated Transmission and Regulated Distribution segments and reposition the Competitive Energy Services segment, FirstEnergy is also focused on reducing balance sheet risk, maintaining investment grade metrics, and improving the business risk profile at each of its businesses. Specifically, at the regulated businesses, authority has been obtained for various regulated distribution and transmission subsidiaries to issue and/or refinance debt. Finally, at the competitive business, FirstEnergy completed the sale of certain hydro assets for approximately $394 million on February 12, 2014. The actions taken in 2013 and the first nine months of 2014, and those planned for the remainder of 2014 are expected to support a primarily regulated investment strategy.

Operational Matters

Union Employee Relations

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. The CBA with Local 102, which represents approximately 700 employees at WP and PE, expired on April 30, 2013. UWUA Local 102 rejected the companies' offer of a 5-year CBA and continues to work under the previously expired CBA. FirstEnergy continues to engage in negotiations with both Locals 272 and 102, 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.

Regulatory Matters

WV ENEC Case Update

On August 29, 2014, MP and PE filed their annual ENEC case proposing an approximate $65.8 million annual increase in rates, which is a 5.7% overall increase over existing rates. The $65.8 million 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. This proceeding includes a two-year review period as there was not an annual ENEC filing in 2013 pursuant to party agreement and WVPSC consent during MP and PE’s 2013 proceeding authorizing the Harrison/Pleasants asset transfer. An order is expected to be issued before the end of 2014.

WV Rate Case Update

In the MP and PE rate case, which was filed on April 30, 2014 and updated on June 13, 2014, MP and PE requested an overall increase in rates of $152 million, or 14.7%. On November 3, 2014, a Joint Stipulation was submitted by all parties which resolves all issues in the pending proceeding and 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 operating and maintenance expenses and capital costs related to a new vegetation maintenance program; authority to establish a regulatory asset for MATS investments placed into service in 2016 and 2017 and recover in the next base rate case; authority to defer, amortize and recover over a 5-year period approximately $46 million of restoration costs associated with the 2012 Derecho and Hurricane Sandy storms; and elimination of the Temporary Transaction Surcharge and movement of the costs currently being collected for the 2013 Harrison generation transaction into base rates effective February 25, 2015. The settlement is subject to review and approval of the WVPSC. The WVPSC has scheduled a hearing for November 7, 2014, to evaluate the settlement and its terms.

New Jersey Base Rate Case Update

On September 30, 2014, the ALJ’s requested second 45-day extension to render an initial decision in the JCP&L base rate case proceeding was approved by the NJBPU. The ALJ’s initial decision is expected to be filed by November 13, 2014.

New Jersey CTA Generic Proceeding Update

On October 22, 2014, the NJBPU issued an Order in its generic proceeding reviewing its policy regarding use of a CTA in base rate cases. The NJBPU stated it would continue to apply its current CTA policy in base rate cases, subject to the modifications proposed by the NJBPU Staff, which would 1) calculate savings using a 5 year look back from the beginning of the test year, 2) allocate savings with 75% retained by the company and 25% allocated to rate payers, and 3) exclude transmission assets of electric distribution companies in the savings calculation. 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 adjustment reflecting this modified policy and allow parties the opportunity to comment. Although FirstEnergy is still reviewing the CTA Order, by our interpretation and calculation, FirstEnergy expects that application of the modified policy in the pending JCP&L base rate case would reduce the CTA revenue adjustment as proposed by certain parties to the case from approximately $56 million to approximately $5 to $6 million.

PJM Market Reform: FERC Order No. 745 - Demand Response

On September 17, 2014, the U.S. Court of Appeals for the D.C. Circuit denied FERC's request for review of the May 23, 2014 D.C. Circuit panel's decision on Order No. 745. As a result, the original decision stands which states that demand response is not a wholesale product but rather a choice of retail customers to not buy power. The court therefore ruled that demand response falls within the states' jurisdiction and cannot be regulated (compensated) in FERC-jurisdictional wholesale markets. Subsequently, the D.C. Circuit "stayed" issuance of its mandate until December 16, 2014, pending potential appeal by FERC to the U.S. Supreme

Court. On September 22, 2014, FirstEnergy filed an amended complaint with FERC, renewing the request that demand response be removed from the May 2014 PJM BRA. The timing of FERC action and the outcome of this proceeding is currently pending.

Financial Matters

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.

FIRSTENERGY’S BUSINESS

FirstEnergy continues to have three reportable operating segments - Regulated Distribution, Regulated Transmission and Competitive Energy Services. The external reporting is consistent with the internal financial reporting used by FirstEnergy’s Chief Executive Officer (its chief operating decision maker) to regularly assess the performance of the business and allocate resources.

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 in West Virginia and New Jersey that MP and JCP&L, respectively, own or contractually control. Its results reflect the commodity costs of securing electric generation and the deferral and amortization of certain fuel costs. This business segment currently controls approximately 3,790 MWs of generation capacity.

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 derived from transmission services provided pursuant to the PJM open access transmission tariff to LSEs. Its results also reflect the net transmission expenses related to the delivery of electricity on FirstEnergy's transmission facilities.

The Competitive Energy Services segment, through FES and AE Supply, supplies electricity to end-use customers through retail and wholesale arrangements, including competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, and the provision of partial POLR and default service for some utilities in Ohio, Pennsylvania and Maryland, including the Utilities. This business segment currently controls approximately 14,000 MWs of capacity, including 885 MWs of capacity scheduled to be deactivated by April 2015. This segment also purchases electricity to meet sales obligations. The segment’s net income is primarily derived from electric generation sales less the related costs of electricity generation, including fuel, purchased power and net transmission (including congestion) and ancillary costs charged by PJM to deliver energy to the segment’s customers.

The Competitive Energy Services segment is taking action to reduce its exposure to weather-sensitive loads, including maintaining competitive generation in excess of committed sales, eliminating load obligations that do not adequately cover risk premiums, pursuing more certain revenue streams, and modifying its hedging strategy to optimize risk management and market upside opportunities. As part of this, the Competitive Energy Services segment has eliminated future selling efforts in certain sales channels, such as mass market, medium commercial-industrial and select large commercial-industrial, 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 as was experienced in the first quarter of 2014. Going forward, the Competitive Energy Services segment will target 65 to 75 million MWHs of sales with a 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, 10 to 20 million MWHs in block wholesale sales and 10 to 20 million MWHs of spot wholesale sales. Support for current customers in the channels to be exited will remain through their respective contract terms.

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

The Competitive Energy Services segment economically hedges exposure to price risk on a ratable basis, which is intended to reduce the near-term financial impact of market price volatility. As of September 30, 2014, committed sales for calendar year 2014 are 98.6 million MWH. For the three months from October to December 2014, supply from expected generation and committed purchases is approximately 105% of committed sales under normal weather conditions. As of September 30, 2014, committed sales for 2015, 2016 and 2017 are approximately 56 million MWHs, 31 million MWHs and 20 million MWHs, respectively. On average, the Competitive Energy Services segment expects to produce approximately 75 - 80 million MWHs of electricity annually, with up to an additional 5 million MWHs related to purchased power agreements for wind, solar and its entitlement to OVEC. The Competitive Energy Services segment fulfills the difference between committed sales, which is based on estimated customer usage, assuming normal weather, and electricity generated, through forward contracts and options, generation produced by its peaking units and purchasing power on the wholesale market, as necessary.

Other and Reconciling Adjustments contains corporate items and other businesses that are below the quantifiable threshold for separate disclosure as a reportable segment as well as reconciling adjustments for the elimination of intersegment transactions. See Note 13, Segment Information, of the Combined Notes to Consolidated Financial Statements for further information on FirstEnergy's reportable operating segments.

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

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

RESULTS OF OPERATIONS

The financial results discussed below include revenues and expenses from transactions among FirstEnergy's segments. A reconciliation of segment financial results is provided in Note 13, Segment Information, of the Combined Notes to Consolidated Financial Statements. Certain prior year amounts have been reclassified to conform to the current year presentation.

Summary of Results of Operations — Third Quarter 2014 Compared with Third Quarter 2013

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

Third Quarter 2014 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$2,304	$197	$1,361	$(38)	$3,824
Other	53	—	45	(34)	64
Internal	—	—	193	(193)	—
Total Revenues	2,357	197	1,599	(265)	3,888
Operating Expenses:					
Fuel	159	—	385	—	544
Purchased power	873	—	508	(193)	1,188
Other operating expenses	473	38	432	(85)	858
Provision for depreciation	165	33	100	10	308
Amortization of regulatory assets, net	33	3	—	(1)	35
General taxes	175	17	40	7	239
Total Operating Expenses	1,878	91	1,465	(262)	3,172
Operating Income (Loss)	479	106	134	(3)	716
Other Income (Expense):					
Investment income	14	—	11	(9)	16
Interest expense	(147)	(35)	(49)	(44)	(275)
Capitalized financing costs	5	14	6	3	28
Total Other Expense	(128)	(21)	(32)	(50)	(231)
Income (Loss) Before Income Taxes (Benefits)	351	85	102	(53)	485
Income taxes (benefits)	124	30	36	(38)	152
Net Income (Loss)	$227	$55	$66	$(15)	$333

Third Quarter 2013 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$2,284	$189	$1,508	$(33)	$3,948
Other	53	—	62	(31)	84
Internal	—	—	196	(196)	—
Total Revenues	2,337	189	1,766	(260)	4,032
Operating Expenses:					
Fuel	88	—	569	—	657
Purchased power	910	—	406	(196)	1,120
Other operating expenses	457	35	457	(72)	877
Provision for depreciation	151	28	125	12	316
Amortization of regulatory assets, net	309	3	—	—	312
General taxes	173	15	49	5	242
Total Operating Expenses	2,088	81	1,606	(251)	3,524
Operating Income (Loss)	249	108	160	(9)	508
Other Income (Expense):					
Gain on debt redemptions	—	—	—	9	9
Investment income (Loss)	14	—	(2)	(7)	5
Interest expense	(134)	(23)	(53)	(47)	(257)
Capitalized financing costs	6	1	10	4	21
Total Other Expense	(114)	(22)	(45)	(41)	(222)
Income (Loss) From Continuing Operations Before Income Taxes (Benefits)	135	86	115	(50)	286
Income taxes (benefits)	50	32	47	(52)	77
Income From Continuing Operations	85	54	68	2	209
Discontinued Operations, net of tax	—	—	9	—	9
Net Income	$85	$54	$77	$2	$218

Changes Between Third Quarter 2014 and Third Quarter 2013 Financial Results Increase (Decrease)	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$20	$8	$(147)	$(5)	$(124)
Other	—	—	(17)	(3)	(20)
Internal	—	—	(3)	3	—
Total Revenues	20	8	(167)	(5)	(144)
Operating Expenses:					
Fuel	71	—	(184)	—	(113)
Purchased power	(37)	—	102	3	68
Other operating expenses	16	3	(25)	(13)	(19)
Provision for depreciation	14	5	(25)	(2)	(8)
Amortization of regulatory assets, net	(276)	—	—	(1)	(277)
General taxes	2	2	(9)	2	(3)
Impairment of long-lived assets	—	—	—	—	—
Total Operating Expenses	(210)	10	(141)	(11)	(352)
Operating Income (Loss)	230	(2)	(26)	6	208
Other Income (Expense):					
Loss on debt redemptions	—	—	—	(9)	(9)
Investment income	—	—	13	(2)	11
Interest expense	(13)	(12)	4	3	(18)
Capitalized financing costs	(1)	13	(4)	(1)	7
Total Other Expense	(14)	1	13	(9)	(9)
Income (Loss) From Continuing Operations Before Income Taxes (Benefits)	216	(1)	(13)	(3)	199
Income taxes (benefits)	74	(2)	(11)	14	75
Income From Continuing Operations	142	1	(2)	(17)	124
Discontinued Operations, net of tax	—	—	(9)	—	(9)
Net Income (loss)	$142	$1	$(11)	$(17)	$115

Regulated Distribution — Third Quarter 2014 Compared with Third Quarter 2013

Net income increased $142 million in the third quarter of 2014 compared to the same period of 2013, as more fully described below.

Revenues —

The $20 million increase in total revenues resulted from the following sources:

Revenues by Type of Service	Three Months Ended September 30 2014	2013	Increase (Decrease)
	(In millions)		
Distribution services	$955	$995	$(40)
Generation sales:			
Retail	1,068	1,090	(22)
Wholesale	165	80	85
Total generation sales	1,233	1,170	63
Transmission	116	119	(3)
Other	53	53	—
Total Revenues	$2,357	$2,337	$20

Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	Three Months Ended September 30 2014	2013	Increase (Decrease)
	(In thousands)		
Residential	13,127	13,911	(5.6)%
Commercial	11,169	11,368	(1.8)%
Industrial	13,142	12,732	3.2%
Other	149	147	1.4%
Total Electric Distribution MWH Deliveries	37,587	38,158	(1.5)%

Lower deliveries to residential and commercial customers primarily reflects decreased weather-related usage resulting from cooling degree days that were 15% below 2013 and 17% below normal. Increased sales in the industrial sector primarily related to shale gas, steel and petroleum customers. For the remainder of 2014, FirstEnergy continues to expect an increase in industrial sales, with a majority of that increase resulting from shale gas activities. FirstEnergy expects growth in the industrial sector beyond 2014 for potential shale gas projects. As new 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 $63 million increase in generation revenues for the third quarter of 2014 compared to the same period of 2013:

Source of Change in Generation Revenues	Increase (Decrease) (In millions)
Retail:	
Effect of decrease in sales volumes	$(20)
Change in prices	(2)
	(22)
Wholesale:	
Effect of increase in sales volumes	72
Change in prices	(19)
Capacity Revenue	32
	85
Increase in Generation Revenues	$63

The decrease in retail generation sales volumes was primarily due to decreased weather-related usage, as described above, and increased customer shopping in Pennsylvania and Maryland. Total generation provided by alternative suppliers as a percentage of total MWH deliveries increased to 68% from 67% for the Pennsylvania Companies and 50% from 49% for PE. The impact of higher retail generation revenues resulting from MP's Temporary Transaction Surcharge associated with the Harrison/Pleasants asset transfer was offset by a rate reduction associated with the recovery of deferred energy costs.

The increase in wholesale generation revenues of $85 million reflects increased volume and capacity revenue resulting from the Harrison/Pleasants asset transfer, whereby MP acquired 1,476 MWs of net capacity in October 2013, partially offset by lower spot market energy prices in the third quarter of 2014 as compared to the same period of 2013.

Operating Expenses —

Total operating expenses decreased $210 million primarily due to the following:

- Fuel expense was $71 million higher in the third quarter of 2014 primarily related to increased generation as a result of the Harrison/Pleasants asset transfer in October of 2013.

- Purchased power costs were $37 million lower primarily due to a decrease in volumes resulting from lower weather-related usage, partially offset by increased capacity expense and higher unit prices due to higher auction clearing prices.

Source of Change in Purchased Power	Increase(Decrease) (In millions)
Purchases from non-affiliates:	
Change due to increased unit costs	$ 5
Change due to decreased volumes	(42)
	(37)
Purchases from affiliates:	
Change due to increased unit costs	6
Change due to decreased volumes	(9)
	(3)
Capacity Expense	22

Increase in costs deferred	(19	)
Decrease in Purchased Power Costs	$ (37	)

- Other operating expenses increased $16 million primarily due to:

- Higher vegetation management expenses of $14 million in West Virginia, which are deferred for future recovery,

- Increased regulated generation operating and maintenance expenses of $10 million, reflecting increased costs associated with the Harrison/Pleasants asset transfer,

- Higher pension and OPEB costs of $8 million primarily associated with lower amortization of prior service cost credits,

- Higher transmission expenses of $5 million due to higher congestion and network transmission costs primarily at MP related to the Harrison/Pleasants asset transfer partially offset by lower PJM charges to the Ohio Companies, and

- Lower energy efficiency expenses and other regulatory program costs of $17 million, which are recovered through rates.

- Depreciation expense increased $14 million due to a higher asset base, including $7 million associated with the Harrison/Pleasants asset transfer.

- Net amortization of regulatory assets decreased $276 million primarily due to a 2013 regulatory asset impairment associated with the recovery of marginal transmission losses at ME and PN and the deferral of vegetation management expenses in West Virginia.

- General taxes increased $2 million due to higher property taxes and West Virginia Business and Occupation taxes, partially offset by lower revenue related taxes.

Other Expense —

Other expense increased $14 million in the third quarter of 2014 primarily due to higher interest expense at MP resulting from new debt issuances of $580 million associated with the financing of the Harrison/Pleasants asset transfer and at JCP&L resulting from a new debt issuance of $500 million in August 2013.

Income Taxes —

Regulated Distribution’s effective tax rate was 35.3% and 37.0% for the quarter ended September 30, 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.

Regulated Transmission — Third Quarter 2014 Compared with Third Quarter 2013

Net income increased $1 million in the third quarter of 2014 compared to the same period of 2013, as more fully described below.

Revenues —

Total revenues increased $8 million principally at ATSI, reflecting incremental cost of service and rate base recovery resulting from its annual rate filing effective June 2014.

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

Revenues by Transmission Asset Owner	Three Months Ended September 30 2014	2013	Increase (Decrease)
	(In millions)		
ATSI	$66	$54	$12
TrAIL	52	56	(4)
PATH	4	5	(1)
Utilities	75	74	1
Total Revenues	$197	$189	$8

Operating Expenses —

Total operating expenses increased $10 million principally due to higher operating and maintenance expenses, associated with vegetation management activities, property taxes and depreciation.

Other Expense —

Other expense decreased $1 million in the third quarter of 2014 primarily due to higher capitalized financing costs of $13 million resulting from increased CWIP primarily 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.

Income Taxes —

Regulated Transmission’s effective tax rate was 35.3% and 37.2% for the quarter ended September 30, 2014 and 2013, respectively. The decrease in the effective tax rate primarily resulted from changes in state apportionment factors, an increase in the benefit of AFUDC equity flow through and other realized tax benefits.
Competitive Energy Services — Third Quarter 2014 Compared with Third Quarter 2013

Net income decreased $11 million in the third quarter of 2014, compared to the same period of 2013, as more fully described below.

Revenues —

Total revenues decreased $167 million in the third quarter of 2014, compared to the same period of 2013, primarily due to decreased sales volumes in the Direct, Governmental Aggregation and Mass Market channels, partially offset by higher Structured sales volumes, increased wholesale revenues resulting from higher capacity rates, and higher unit prices in the Direct, Governmental Aggregation, and POLR and Structured sales channels.

The decrease in total revenues resulted from the following sources:

	Three Months Ended September 30		Increase	
Revenues by Type of Service	2014	2013	(Decrease)	
	(In millions)			
Direct	$547	$767	$(220	)
Governmental Aggregation	327	346	(19	)
Mass Market	112	119	(7	)
POLR and Structured	381	338	43	
Wholesale	151	100	51	
Transmission	36	34	2	
Other	45	62	(17	)
Total Revenues	$1,599	$1,766	$(167	)

	Three Months Ended September 30		Increase (Decrease)	
MWH Sales by Channel	2014	2013		
	(In thousands)			
Direct	10,397	14,725	(29.4	)%
Governmental Aggregation	4,992	5,813	(14.1	)%
Mass Market	1,664	1,774	(6.2	)%
POLR and Structured	7,094	6,358	11.6	%

Wholesale	236	556	(57.6	)%
Total MWH Sales	24,383	29,226	(16.6	)%

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The following table summarizes 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	$(226)	$6	$—	$—	$(220)
Governmental Aggregation	(49)	30	—	—	(19)
Mass Market	(7)	—	—	—	(7)
POLR and Structured Sales	28	15	—	—	43
Wholesale	(10)	(1)	(11)	73	51

The Competitive Energy Services segment has eliminated future selling efforts in certain sales channels, such as mass market, medium commercial-industrial and select large commercial-industrial (Direct sales channel), 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 as was experienced in the first quarter of 2014. The decrease in Direct revenues of $220 million resulted from lower sales volumes from commercial and industrial customers, partially offset by higher unit prices. The decrease in Governmental Aggregation and Mass Market revenues of $19 million and $7 million, respectively, primarily reflects a lower customer base and decreased weather-related usage resulting from cooling degree days that were 15% lower than the third quarter of 2013 partially offset by increased Governmental Aggregation unit prices. The Direct, Governmental Aggregation and Mass Market customer base was 2.3 million as of September 30, 2014 compared to 2.7 million as of September 30, 2013, reflecting the segment's efforts to reposition its sales portfolio to more effectively hedge its generation. Higher unit prices as described above resulted from increased channel pricing primarily associated with higher capacity rates.

The increase in POLR and Structured sales of $43 million was due to higher structured sales volumes and rates as well as higher POLR rates associated with recent auctions, partially offset by lower POLR sales volumes due to decreased weather-related usage.

Wholesale revenues increased $51 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 and gains on financially settled contracts. 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.

Other revenue decreased $17 million primarily due to an $18 million pre-tax gain recognized in 2013 on the sale of property to a regulated affiliate.

Operating Expenses —

Total operating expenses decreased by $141 million in the third quarter of 2014 due to the following:

- Fuel costs decreased $184 million primarily due to lower volumes associated with the Harrison/Pleasants asset transfer and the deactivation of certain power plants in 2013, partially offset by a slight increase in nuclear generation. Lower fossil unit prices and lower nuclear unit prices, as a result of the suspension of the DOE disposal fee, which became effective May 16, 2014, also contributed to the decrease. Additionally, fuel costs in the third quarter of 2013 were impacted by settlement and termination costs related to coal and transportation contracts of $27 million.

- Purchased power costs increased $102 million due to higher capacity expenses ($107 million) and losses on financially settled contracts ($46 million), partially offset by lower prices ($45 million) and lower volumes ($6 million) resulting from lower contract sales net of additional volume required as a result of the Harrison/Pleasants asset transfer. The increase in capacity expense was the result of higher capacity rates.

- Fossil operating costs decreased $22 million primarily due to lower contractor, labor and materials and equipment costs resulting from previously deactivated units and the Harrison/Pleasants asset transfer.

- Nuclear operating costs decreased $9 million as a result of pre-outage activities associated with the fall refueling outage in the third quarter of 2013. There were no fall refueling outages in the third quarter of 2014.

- Transmission expenses decreased $22 million primarily due to lower ancillary and network costs resulting from decreased retail sales and lower congestion prices, partially offset by a credit received in the third quarter of 2013 for previously incurred PJM transmission costs associated with RMR units in the ATSI zone.

- General taxes decreased $9 million primarily due to lower gross receipts taxes associated with decreased retail sales volumes and lower property taxes due to the Harrison/Pleasants asset transfer.
- Depreciation expense decreased $25 million primarily due to a reduction in the asset base as a result of plant deactivations and the Harrison/Pleasants asset transfer noted above, partially offset by capital assets placed in service.
- Other operating expenses increased $28 million primarily due to an increase in mark-to-market expenses on commodity contract positions.

Other Expense —

Total other expense in the third quarter of 2014 decreased $13 million compared to the same period of 2013 primarily due to lower OTTI on NDT investments, partially offset by lower capitalized financing costs primarily due to the completion of the steam generator replacement at the Davis-Besse nuclear plant in May 2014.

Income Tax Benefits —

Competitive energy services effective tax rate was 35.3% and 40.9% for the quarter ended September 30, 2014 and 2013, respectively. The decrease in the effective tax rate primarily resulted from changes in state apportionment factors and other realized tax benefits.

Other — Third Quarter 2014 Compared with Third Quarter 2013

Financial results from other operating segments and reconciling items, including interest expense on holding company debt, corporate support services revenues and expenses and income taxes, resulted in a $17 million decrease in earnings in the third quarter of 2014 compared to the same period of 2013 primarily due to lower tax benefits and gains on debt redemptions recognized in the third quarter of 2013. In the third quarter of 2013, the Other segment benefited from reductions to valuation allowances against state NOL carryforwards, as well as changes in state apportionment factors, which reduced deferred tax liabilities. In the third quarter of 2014, the Other segment benefited primarily from an IRS-approved change in accounting method that increased the tax basis in certain assets resulting in higher future tax deductions, partially offset by a valuation allowance against local NOL carryforwards.

Summary of Results of Operations — First Nine Months of 2014 Compared with First Nine Months of 2013

Financial results for FirstEnergy's business segments in the first nine months of 2014 and 2013 were as follows:

First Nine Months 2014 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$6,822	$570	$4,099	$(145)	$11,346
Other	150	—	140	(70)	220
Internal	—	—	624	(624)	—
Total Revenues	6,972	570	4,863	(839)	11,566
Operating Expenses:					
Fuel	441	—	1,270	—	1,711
Purchased power	2,600	—	1,750	(624)	3,726
Other operating expenses	1,580	103	1,625	(247)	3,061
Provision for depreciation	491	93	287	33	904
Amortization of regulatory assets, net	18	9	—	—	27
General taxes	528	52	133	25	738
Total Operating Expenses	5,658	257	5,065	(813)	10,167
Operating Income (Loss)	1,314	313	(202)	(26)	1,399
Other Income (Expense):					
Loss on debt redemptions	—	—	(8)	—	(8)
Investment income	44	—	46	(23)	67
Interest expense	(445)	(90)	(143)	(124)	(802)
Capitalized financing costs	12	38	28	11	89
Total Other Expense	(389)	(52)	(77)	(136)	(654)
Income (Loss) From Continuing Operations Before Income Taxes	925	261	(279)	(162)	745
Income taxes (benefits)	326	92	(102)	(90)	226
Income (Loss) From Continuing Operations	599	169	(177)	(72)	519
Discontinued Operations, net of tax	—	—	86	—	86
Net Income (Loss)	$599	$169	$(91)	$(72)	$605

First Nine Months 2013 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$6,414	$544	$4,204	$(126)	$11,036
Other	170	—	148	(95)	223
Internal	—	—	588	(588)	—
Total Revenues	6,584	544	4,940	(809)	11,259
Operating Expenses:					
Fuel	250	—	1,665	—	1,915
Purchased power	2,547	—	973	(588)	2,932
Other operating expenses	1,274	98	1,517	(244)	2,645
Provision for depreciation	446	84	347	32	909
Amortization of regulatory assets, net	436	7	—	—	443
General taxes	527	41	158	21	747
Impairment of long-lived assets	—	—	473	—	473
Total Operating Expenses	5,480	230	5,133	(779)	10,064
Operating Income (Loss)	1,104	314	(193)	(30)	1,195
Other Income (Expense):					
Gain (Loss) on debt redemptions	—	—	(149)	17	(132)
Investment income (Loss)	41	—	(8)	(25)	8
Interest expense	(404)	(68)	(187)	(112)	(771)
Capitalized financing costs	17	3	31	11	62
Total Other Expense	(346)	(65)	(313)	(109)	(833)
Income (Loss) From Continuing Operations Before Income Taxes (Benefits)	758	249	(506)	(139)	362
Income taxes (benefits)	284	93	(189)	(59)	129
Income (Loss) From Continuing Operations	474	156	(317)	(80)	233
Discontinued Operations, net of tax	—	—	17	—	17
Net Income (Loss)	$474	$156	$(300)	$(80)	$250

Changes Between First Nine Months 2014 and First Nine Months 2013 Financial Results Increase (Decrease)	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$408	$26	$(105)	$(19)	$310
Other	(20)	—	(8)	25	(3)
Internal	—	—	36	(36)	—
Total Revenues	388	26	(77)	(30)	307
Operating Expenses:					
Fuel	191	—	(395)	—	(204)
Purchased power	53	—	777	(36)	794
Other operating expenses	306	5	108	(3)	416
Provision for depreciation	45	9	(60)	1	(5)
Amortization of regulatory assets, net	(418)	2	—	—	(416)
General taxes	1	11	(25)	4	(9)
Impairment of long-lived assets	—	—	(473)	—	(473)
Total Operating Expenses	178	27	(68)	(34)	103
Operating Income (Loss)	210	(1)	(9)	4	204
Other Income (Expense):					
Loss on debt redemptions	—	—	141	(17)	124
Investment income	3	—	54	2	59
Interest expense	(41)	(22)	44	(12)	(31)
Capitalized financing costs	(5)	35	(3)	—	27
Total Other Expense	(43)	13	236	(27)	179
Income (Loss) From Continuing Operations Before Income Taxes (Benefits)	167	12	227	(23)	383
Income taxes (benefits)	42	(1)	87	(31)	97
Income (Loss) From Continuing Operations	125	13	140	8	286
Discontinued Operations, net of tax	—	—	69	—	69
Net Income (Loss)	$125	$13	$209	$8	$355

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Regulated Distribution — First Nine Months of 2014 Compared with First Nine Months of 2013

Net income increased $125 million in the first nine months of 2014 compared to the same period of 2013, as more fully described below.

Revenues —

The $388 million increase in total revenues resulted from the following sources:

Revenues by Type of Service	Nine Months Ended September 30 2014	2013	Increase (Decrease)
	(In millions)		
Distribution services	$2,792	$2,860	$(68)
Generation sales:			
Retail	3,097	3,014	83
Wholesale	541	203	338
Total generation sales	3,638	3,217	421
Transmission	392	337	55
Other	150	170	(20)
Total Revenues	$6,972	$6,584	$388

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 program costs for the Pennsylvania Companies. This was partially offset by higher electric distribution MWH deliveries as described below and an increase in the Ohio Companies' DCR rider revenues. Distribution deliveries increased by 1.7% in the first nine months of 2014 compared to the same period of 2013. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	Nine Months Ended September 30 2014	2013	Increase
	(In thousands)		
Residential	41,616	40,996	1.5 %
Commercial	32,552	32,058	1.5 %
Industrial	38,604	37,851	2.0 %
Other	439	436	0.7 %
Total Electric Distribution MWH Deliveries	113,211	111,341	1.7 %

Higher deliveries to residential and commercial customers primarily reflect increased weather-related usage resulting from heating degree days that were 12% above 2013 and 14% above normal, partially offset by cooling degree days that were 13% below 2013 and 12% below normal. In the industrial sector, increased sales to steel, automotive and shale gas customers were partially offset by lower sales to chemical and paper customers.

The following table summarizes the price and volume factors contributing to the $486 million increase in generation revenues for the first nine months of 2014 compared to the same period of 2013:

Source of Change in Generation Revenues	Increase (In millions)
Retail:	
Effect of increase in sales volumes	$1
Change in prices	82
	83
Wholesale:	
Effect of increase in sales volumes	173
Change in prices	100
Capacity Revenue	65
	338
Increase in Generation Revenues	$421

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 associated with the Harrison/Pleasants asset transfer was offset by a rate reduction associated with the recovery of deferred energy costs.

The increase in wholesale generation revenues of $338 million in the first nine months of 2014 as compared to the same period of 2013 reflects increased volume and energy prices associated with market conditions related to extreme weather events in January 2014 and increased capacity revenue related to the Harrison/Pleasants asset transfer whereby MP acquired 1,476 MWs of net capacity.

The increase in transmission revenues of $55 million reflects higher FTR revenues at MP associated with market conditions related to extreme weather events in January 2014 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 $20 million primarily due to less customer requested work in the first nine months of 2014 compared to the same period of 2013.

Operating Expenses —

Total operating expenses increased $178 million primarily due to the following:

- Fuel expense was $191 million higher in the first nine months of 2014 primarily related to increased generation as a result of the Harrison/Pleasants asset transfer in October of 2013.

- Purchased power costs were $53 million higher primarily due to increased unit prices reflecting higher auction clearing prices and increased capacity expense during the first nine months of 2014 compared to the same period of 2013, partially offset by a decrease in 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	(118)
	9
Purchases from affiliates:	
Change due to increased unit costs	40
Change due to decreased volumes	(4)
	36
Capacity Expense	36
Increase in costs deferred	(28)
Increase in Purchased Power Costs	$ 53

- Other operating expenses increased $306 million primarily due to:

- Higher transmission expenses of $137 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 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 $73 million primarily due to higher maintenance activities and storm-related restoration costs, including $22 million associated with Winter Storm Nika during the first quarter of 2014, of which $15 million was deferred for future recovery.

- Higher vegetation management expenses in West Virginia of $21 million, which were deferred for future recovery.

- Higher pension and OPEB costs of $27 million primarily associated with lower amortization of prior service cost credits.

- Increased regulated generation operating and maintenance expenses of $40 million, reflecting increased costs associated with the Harrison/Pleasants asset transfer and a planned outage at Fort Martin.

- Depreciation expense increased $45 million due to a higher asset base, including $21 million associated with the Harrison/Pleasants asset transfer.

- Net amortization of regulatory assets decreased $418 million primarily due to a 2013 regulatory asset impairment associated with the recovery of marginal transmission losses at ME and PN ($254 million), higher storm cost deferrals, lower Pennsylvania default generation service and NUG cost recovery, increased deferred vegetation management expenses in West Virginia and decreased energy efficiency amortization reflecting a rate decrease associated with certain programs for the Pennsylvania Companies.

Other Expense —

Other expense increased $43 million in the first nine months of 2014 primarily due to higher interest expense at MP resulting from new debt issuances of $580 million associated with the financing of the Harrison/Pleasants asset transfer and at JCP&L resulting from a new debt issuance of $500 million in August 2013.

Income Taxes —

Regulated Distribution's effective tax rate was 35.2% and 37.5% for the first nine months of 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.

Regulated Transmission — First Nine Months of 2014 Compared with First Nine Months of 2013

Net income increased $13 million in the first nine months of 2014 compared to the same period of 2013, as more fully described below.

Revenues —

Total revenues increased $26 million principally at ATSI and TrAIL, reflecting cost of service and incremental 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	Nine Months Ended September 30		Increase
	2014	2013	(Decrease)
	(In millions)		
ATSI	$176	$154	$22
TrAIL	161	154	7
PATH	9	15	(6)
Utilities	224	221	3
Total Revenues	$570	$544	$26

Operating Expenses —

Total operating expenses increased $27 million principally due to higher property taxes, depreciation and other expenses.

Other Expense —

Other expense decreased $13 million in the first nine months of 2014 compared to the same period of 2013 primarily due to higher capitalized financing costs of $22 million associated with increased CWIP primarily 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.

Income Taxes —

Regulated Transmission’s effective tax rate was 35.2% and 37.3% for the first nine months of 2014 and 2013, respectively. The decrease in the effective tax rate primarily resulted from changes in state apportionment factors, an increase in AFUDC equity flow through and other realized tax benefits.

Competitive Energy Services — First Nine Months of 2014 Compared with First Nine Months of 2013

For the first nine months of 2014, the Competitive Energy Services segment reported a net loss of $91 million compared to a net loss of $300 million for the same period of 2013.

Revenues —

Total revenues decreased $77 million in the first nine months of 2014, compared to the same period of 2013, primarily due to decreased sales volumes in the Direct, Governmental Aggregation, and POLR sales channels, partially offset by higher Mass Market and Structured sales volumes. Revenues were also impacted by higher unit prices compared to 2013 as a result of increased channel pricing and ancillary pass through revenues associated with PJM expenses incurred in January 2014, partially offset by lower prices in Structured sales. Revenues were also impacted by increased Transmission and Wholesale revenue.

The increase in total revenues resulted from the following sources:

Revenues by Type of Service	Nine Months Ended September 30 2014	2013	Increase (Decrease)
	(In millions)		
Direct	$1,879	$2,202	$(323)
Governmental Aggregation	924	911	13
Mass Market	354	335	19
POLR and Structured	1,066	971	95
Wholesale	313	258	55
Transmission	187	115	72
Other	140	148	(8)
Total Revenues	$4,863	$4,940	$(77)

MWH Sales by Channel	Nine Months Ended September 30 2014	2013	Increase (Decrease)
	(In thousands)		
Direct	35,069	42,347	(17.2)%
Governmental Aggregation	15,413	15,975	(3.5)%
Mass Market	5,294	5,045	4.9%
POLR and Structured	21,535	18,716	15.1%
Wholesale	268	1,394	(80.8)%
Total MWH Sales	77,579	83,477	(7.1)%

The following table summarizes the price and volume factors contributing to changes in revenues:

MWH Sales Channel:	Source of Change in Revenues Increase (Decrease) Sales Volumes	Prices	Gain on Settled Contracts	Capacity Revenue	Total
	(In millions)				
Direct	$(379)	$56	$—	$—	$(323)
Governmental Aggregation	(32)	45	—	—	13
Mass Market	17	2	—	—	19
POLR and Structured Sales	132	(37)	—	—	95
Wholesale	(34)	(1)	(7)	97	55

The Competitive Energy Services segment has eliminated future selling efforts in certain sales channels, such as mass market, medium commercial-industrial and select large commercial-industrial (Direct sales channel), 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 as was experienced in the first quarter of 2014. The decrease in Direct revenues of $323 million resulted from lower sales volumes from commercial and industrial customers, partially offset by higher unit prices. The increase in Governmental Aggregation revenues of $13 million primarily reflects higher unit prices, partially offset by lower sales volumes. The increase in Mass Market of $19 million resulted from the acquisition of new customers prior to the repositioning of the segment and slightly higher unit prices. The Direct, Governmental Aggregation and Mass Market customer base was 2.3 million as of September 30, 2014 compared to 2.7 million as of September 30, 2013 reflecting the segment's efforts to reposition its sales portfolio to more effectively hedge its generation. Higher unit prices in each of the sales channels noted above resulted from increased channel pricing primarily associated with higher capacity rates. 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, FirstEnergy's Competitive Energy Services segment (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. 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 revenue of approximately $33 million associated with commercial and industrial customers was recognized in the first quarter of 2014.

The increase in POLR and Structured sales of $95 million was due to higher Structured sales volumes, partially offset by higher POLR rates associated with recent auctions and lower structured 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 $55 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.

Transmission revenue increased $72 million due to higher congestion revenue driven by market conditions related to extreme weather events in the first quarter 2014.

Other revenue decreased $8 million primarily due to an $18 million pre-tax gain recognized in 2013 on the sale of property to a regulated affiliate, partially offset by higher lease revenues from additional repurchased equity interests in affiliated sale and leasebacks since the first nine months of 2013. Competitive Energy Services earns lease revenue associated with the equity interests it purchased.

Operating Expenses —

Total operating expenses decreased $68 million in the first nine months of 2014 due to the following:

- Fuel costs decreased $395 million primarily due to lower generation volumes resulting from the 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 became effective May 16, 2014. Additionally, fuel costs were impacted by an increase in settlement and termination costs related to coal and transportation contracts. In the first nine months of 2014, fuel supply agreements were terminated for approximately $85 million, while settlements associated with damages on coal and transportation contracts were $61 million in the first nine months of 2013.
- Purchased power costs increased $777 million due to higher volumes ($466 million), increased prices ($515 million), and higher capacity expenses ($221 million), partially offset by lower losses on financially settled contracts ($425 million). Higher purchased volumes were primarily due to lower available generation due to outages, the Harrison/Pleasants asset transfer and the deactivation of certain power plants in 2013, partially offset by lower contract sales. The increase in 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. 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. The increase in capacity expense was primarily the result of higher capacity rates.

- Fossil operating costs decreased $96 million primarily due to lower contractor, labor and materials and equipment costs resulting from previously deactivated units and the Harrison/Pleasants asset transfer.

- Nuclear operating costs increased $25 million as a result of higher contractor, materials and equipment costs associated with refueling outages. There were two refueling outages in the first nine months of 2014 as compared to one outage in the first nine months of 2013.

- Transmission expenses increased $105 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.
- General taxes decreased $25 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 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 $60 million primarily due to a reduction in the asset base as a result of the plant deactivations and the Harrison/Pleasants asset transfer noted 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 of $22 million associated with the elimination of future selling efforts in the Mass Market and Medium Commercial-Industrial sales channels.

Other Expense —

Total other expense in the first nine months of 2014 decreased $236 million compared to the same period of 2013 due to the absence of a $141 million loss on debt redemption in connection with senior notes that were repurchased in 2013, lower OTTI, higher investment income primarily on NDT investments, and lower net interest expense of $41 million due to debt redemptions in 2013.

Income Tax Benefits —

Competitive Energy Services' effective tax rate was 36.6% and 37.4% for the first nine months of 2014 and 2013, respectively. The decrease in the effective tax rate, which resulted in a lower tax benefit on pretax losses, primarily resulted from changes in state apportionment factors and other realized tax benefits.

Discontinued Operations —

Discontinued operations increased net income $69 million in the first nine months of 2014 compared to the same period of last year primarily due to a pre-tax gain of approximately $142 million associated with the sale of hydro assets in February 2014.

Other — First Nine Months of 2014 Compared with First Nine Months of 2013

Financial results from other operating segments and reconciling items resulted in a $8 million improvement in earnings in the first nine months of 2014 compared to the same period of 2013 primarily due to higher tax benefits, partially offset by gains on debt redemptions in 2013 and increased interest expense resulting from the issuance of $1 billion of long-term debt at FE in the first quarter of 2014. Tax benefits in the first nine months of 2014 primarily resulted from an IRS approved change in accounting method that increased the tax basis of certain assets resulting in higher future tax deductions as well as the elimination of state tax obligations associated with basis differences and changes in state allocation factors, partially offset by a valuation allowance against local NOL carryforwards. 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.

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 September 30, 2014 and December 31, 2013, and the changes during the nine months ended September 30, 2014:

Regulatory Assets (Liabilities) by Source	September 30, 2014	December 31, 2013	Increase (Decrease)
	(In millions)		
Regulatory transition costs	$244	$266	$(22)
Customer receivables for future income taxes	490	518	(28)
Nuclear decommissioning and spent fuel disposal costs	(219)	(198)	(21)
Asset removal costs	(253)	(362)	109

Deferred transmission costs	92	112	(20)
Deferred generation costs	295	346	(51)
Deferred distribution costs	185	194	(9)
Contract valuations	157	260	(103)
Storm-related costs	463	455	8
Other	214	263	(49)
Net Regulatory Assets included on the Consolidated Balance Sheets	$1,668	$1,854	$(186)

Regulatory assets that do not earn a current return totaled approximately $470 million as of September 30, 2014 primarily related to storm damage costs.

As of September 30, 2014 and December 31, 2013, FirstEnergy had approximately $304 million and $440 million, respectively, of net regulatory liabilities that are primarily related to asset removal costs. Net regulatory liabilities are classified within Other noncurrent liabilities on the Consolidated Balance Sheets.

CAPITAL RESOURCES AND LIQUIDITY

FirstEnergy expects its existing sources of liquidity to remain sufficient to meet its anticipated obligations and those of its subsidiaries. FirstEnergy's business is capital intensive, requiring significant resources to fund operating expenses, construction expenditures, scheduled debt maturities and interest and dividend payments. In addition to internal sources to fund liquidity and capital requirements for 2014 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. On September 16, 2014, the Board declared a dividend of $0.36 per share of outstanding common stock payable December 1, 2014 to shareholders of record at the close of business on November 7, 2014.

FirstEnergy's strategy is to focus on growth through 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 expenditure forecast for 2014 is approximately $1.35 billion. In total, FirstEnergy has identified at least $7 billion in transmission investment opportunities across the 24,000 mile transmission system, making this a continuing platform for growth in the years beyond 2017.

In alignment with FirstEnergy's strategy to focus on growing the Regulated Transmission and Regulated Distribution segments and reposition the Competitive Energy Services segment, FirstEnergy is also focused on reducing balance sheet risk, maintaining investment grade metrics, and improving the business risk profile at each of its businesses. Specifically, at the regulated businesses, authority has been obtained for various regulated distribution and transmission subsidiaries to issue and/or refinance debt. Finally, at the competitive business, FirstEnergy completed the sale of certain hydro assets for approximately $394 million on February 12, 2014. The actions taken in 2013 and the first nine months of 2014, and those planned for the remainder of 2014 are expected to support a primarily regulated investment strategy.

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 September 30, 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 September 30, 2014, included the following:

Currently Payable Long-Term Debt	(In millions)

PCRBs supported by bank LOCs[(1)]	$92
Unsecured notes	450
FMB	320
Unsecured PCRBs[(1)]	339
Collateralized lease obligation bonds	81
Sinking fund requirements	102
Other notes	2
	$1,386

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

Short-Term Borrowings

FirstEnergy had $1,621 million of short-term borrowings as of September 30, 2014, and $3,404 million as of December 31, 2013. FirstEnergy’s available liquidity as of October 31, 2014, was as follows:

Borrower(s)	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy[1]	Revolving	March 2019	$3,500	$2,094
FES / AE Supply	Revolving	March 2019	1,500	1,452
FET[2]	Revolving	March 2019	1,000	925
		Subtotal	$6,000	$4,471
		Cash	—	97
		Total	$6,000	$4,568

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

Revolving Credit Facilities

FirstEnergy, FES/AE Supply and FET Facilities

FE and certain of its subsidiaries participate in three five-year syndicated revolving credit facilities with aggregate commitments of $6.0 billion (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 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 Gain (Loss) on Debt Redemptions in the Consolidated Statement of Income in the first nine months of 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 September 30, 2014:

Borrower	FE Revolving Credit Facility Sublimit	FES/AE Supply Revolving Credit Facility Sublimit	FET Revolving Credit Facility Sublimit	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 open market 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 sublimit, 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 September 30, 2014, the borrowers were in compliance 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, due December 31, 2015. Each of the term loans contains covenants and other terms and conditions substantially similar to those of the FE Facility described above, including the same consolidated debt to total capitalization ratio requirement.

As of September 30, 2014, FE was in compliance 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 rates for borrowings in the first nine months of 2014 were 1.62% per annum for the regulated companies' money pool and 1.40% per annum for the unregulated companies' money pool.

Pollution Control Revenue Bonds

As of September 30, 2014, FirstEnergy's currently payable long-term debt included approximately $92 million (all applicable to FES) of variable interest rate PCRBs, the bondholders of which are entitled to the benefit of irrevocable direct pay bank LOCs. The interest rates on the PCRBs are reset daily or weekly. Bondholders can tender their PCRBs for mandatory purchase prior to maturity with the purchase price payable from remarketing proceeds or, if the PCRBs are not successfully remarketed, by drawings on the irrevocable direct pay LOCs. The subsidiary obligor is required to reimburse the applicable LOC bank for any such drawings or, if the LOC bank fails to honor its LOC for any reason, must itself pay the purchase price. The LOCs for FirstEnergy's variable interest rate PCRBs outstanding as of September 30, 2014 were issued by the following bank:

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 September 30, 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 September 30, 2014, FE and its subsidiaries could issue additional debt of approximately $4.7 billion and remain within the limitations of the financial covenants required by the Facilities. As of September 30, 2014, FES' incremental debt capacity under its consolidated debt to total capitalization financial covenant is also $4.7 billion given FE's consolidated debt to total capitalization ratio under its Facility.

Changes in Cash Position

As of September 30, 2014, FirstEnergy had $109 million of cash and cash equivalents compared to $218 million of cash and cash equivalents as of December 31, 2013. As of September 30, 2014 and December 31, 2013, FirstEnergy had approximately $65 million and $103 million, respectively, of restricted cash included in Other Current Assets on the Consolidated Balance Sheets.

Cash Flows From Operating Activities

FirstEnergy's consolidated net cash from operating activities was provided by its regulated distribution, regulated transmission and competitive energy services businesses (see Results of Operations above). Net cash provided from operating activities was $1,737 million during the first nine months of 2014 compared with $1,671 million provided from operating activities during the first nine months of 2013, as summarized in the following table:

	Nine Months Ended September 30		
Operating Cash Flows	2014	2013	Increase (Decrease)
	(In millions)		
Net income	$605	$250	$355
Non-cash charges	1,205	2,036	(831)
Working capital and other	(73)	(615)	542
Net cash provided from operating activities	$1,737	$1,671	$66

The $831 million decrease in non-cash charges is primarily due to the following:

- a $416 million decrease in the amortization of regulatory assets as discussed above, and
- a $473 million impairment of long-lived assets recognized in 2013 resulting from the Hatfield's Ferry and Mitchell plant deactivations.

The $542 million year over year improvement in working capital is primarily due to the following:

- lower payments to vendors of approximately $232 million primarily resulting from payments in 2013 related to restoration costs associated with Hurricane Sandy,
- lower tax and other payments of approximately $101 million,
- increased retail receipts of approximately $97 million associated with higher weather related usage primarily in the first quarter of 2014, and
- higher accrued interest of approximately $37 million associated with issuances of long-term debt, and
- make whole premiums paid during 2013 of approximately $181 million, partially offset by
- higher materials and supplies inventory purchases of approximately $136 million.

Cash Flows From Financing Activities

In the first nine months of 2014, cash provided from financing activities was $444 million compared to $654 million during the first nine months of 2013. The following table summarizes new debt financing (net of any discounts) and redemptions and repurchases:

Securities Issued or Redeemed / Repaid	Nine Months Ended September 30 2014	2013
	(In millions)	
New Issues		
PCRBs	$878	$—
Term Loan	1,050	—
Senior secured notes	—	445
Unsecured Notes	1,850	2,300
	$3,778	$2,745
Redemptions / Repayments		
PCRBs	$(767)	$(234)
Long-term revolving credit	—	(40)
Senior secured notes	(146)	(353)
Unsecured notes	(149)	(2,035)
	$(1,062)	$(2,662)
Tender premiums paid on debt redemptions	$—	$(110)
Short-term borrowings, net	$(1,783)	$1,435

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 Gain (Loss) on Debt Redemptions in the Consolidated Statement of Income in the first nine months of 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 PCRB's at maturity.

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.

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

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 company 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 utility 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.

Cash Flows From Investing Activities

Cash used for investing activities in the first nine months of 2014 principally represented cash used for property additions. The following table summarizes investing activities for the first nine months of 2014 and the comparable period of 2013:

	Nine Months Ended September 30		
Cash Used for Investing Activities	2014	2013	Increase (Decrease)
	(In millions)		
Property Additions:			
Regulated Distribution	$780	$980	$(200)
Regulated Transmission	980	291	689
Competitive Energy Services	655	630	25
Other and reconciling adjustments	58	59	(1)
Nuclear fuel	98	159	(61)
Proceeds from asset sales	(394)	—	(394)
Investments	40	34	6
Asset removal costs	80	125	(45)
Other	(7)	(3)	(4)
	$2,290	$2,275	$15

Net cash used for investing activities during the first nine months of 2014 increased by $15 million compared to the same period of 2013 primarily due to increased property additions 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.

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 and its subsidiaries could be required to make under these guarantees as of September 30, 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)	$161
Deferred compensation arrangements	478
Other(2)	33
	672
Subsidiaries’ Guarantees	
Energy and Energy-Related Contracts(3)	118
FES’ guarantee of NG’s nuclear property insurance	89
Nuclear decommissioning costs(4)	174
FES’ guarantee of FG’s sale and leaseback obligations	1,930
	2,311
FE's Guarantees on Behalf of Business Ventures	
Global Holding facility	330
Other Assurances	
Surety Bonds - Wholly Owned Subsidiaries	442
Surety Bonds	25
FES' LOC (long-term tax-exempt debt)(5)	93
LOCs(6)	88
	648
Total Guarantees and Other Assurances	$3,961

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

(2) Includes guarantees of $16 million supporting railcar leases, $8 million for various leases and $9 million of other guarantees.

(3) Includes Energy and Energy-Related Contracts associated with FES of approximately $113 million.

(4) Upon acceptance by the NRC, 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 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 $54 million issued for various terms pursuant to LOC capacity available under FirstEnergy’s revolving credit facilities, $12 million pledged in connection with the sale and leaseback of Beaver Valley Unit 2 by OE and $22 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 FirstEnergy and its subsidiaries have margining provisions that require posting of collateral. Based on the Competitive Energy Segments power portfolio exposures as of September 30, 2014, FES has posted collateral of $197 million and AE Supply has posted no collateral.The Regulated Distribution segment has posted collateral of $3 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 as of September 30, 2014:

Collateral Provisions	FES	AE Supply	Utilities	Total
	(In millions)			
Split Rating (One rating agency's rating below investment grade)	$490	$6	$56	$552
BB+/Ba1 Credit Ratings	$533	$6	$56	$595
Full impact of credit contingent contractual obligations	$784	$68	$94	$946

Excluded from the preceding table is the potential collateral obligations due to affiliate transactions between the Regulated Distribution Segment and Competitive Energy Services Segment. As of September 30, 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 $78 million with affiliated parties.

Other Commitments and Contingencies

FE is a guarantor under a syndicated three-year senior secured term loan facility dated October 18, 2011, as amended, that matures 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 FE, 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 guarantees of the obligations of Global Holding under the new facility.

In connection with the 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 as collateral.

FE, FEV and the other two co-owners of Global Holding, Pinesdale LLC, a Gunvor Group, Ltd. subsidiary, and WMB Marketing Ventures, LLC, have agreed, most recently as of August 14, 2013, to use their best efforts to refinance the facility no later than July 20, 2015, on a non-recourse basis so that FE's guaranty can be terminated and/or released. If that refinancing does not occur, FE may require each co-owner to lend to Global Holding, on a pro rata basis, funds sufficient to prepay the facility in full. In lieu of providing such funding, the co-owners, at FE's option, may provide their several guaranties of Global Holding's obligations under the facility. Since January 1, 2013, FE has received a fee for providing its guaranty. The fee is payable semiannually, and accrues at a rate of 5% per annum on the average daily outstanding aggregate commitments under the facility for each 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 September 30, 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. As of September 30, 2014, FirstEnergy's leasehold interest was 8.11% 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 representing approximately half 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. Finally, NG has recently reached an agreement in principle with the owner participants regarding its acquisition of the remaining lessor equity interests in OE's existing sale and leaseback of Perry Unit 1. However, no assurance can be given that an agreement will be finalized and the acquisition of the remaining Perry Unit 1 lessor equity interests will be completed.

MARKET RISK INFORMATION

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

Commodity Price Risk

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

The valuation of derivative contracts is based on observable market information to the extent that such information is available. In cases where such information is not available, FirstEnergy relies on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. FirstEnergy uses these results to develop estimates of fair value for financial reporting purposes and for internal management decision making (see Note 8, Fair Value Measurements, of the Combined Notes to Consolidated Financial Statements). Sources of information for the valuation of derivative contracts assets and liabilities as of September 30, 2014 are summarized by year in the following table:

Source of Information-Fair Value by Contract Year	2014	2015	2016	2017	2018	Thereafter	Total
	(In millions)						
Prices actively quoted[(1)]	$(9)	$(8)	$—	$—	$—	$—	$(17)

Other external sources[2]	(15)	(43)	(22)	(18)	—	—	(98)
Prices based on models	7	18	1	(1)	(14)	(15)	(4)
Total[3]	$(17)	$(33)	$(21)	$(19)	$(14)	$(15)	$(119)

(1) Represents exchange traded New York Mercantile Exchange futures and options.
(2) Primarily represents contracts based on broker and ICE quotes.
(3) Includes $(155) million in non-hedge derivative contracts 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 held as of September 30, 2014, a 10% adverse change in commodity prices would decrease net income by approximately $4 million during the next 12 months.

Equity Price Risk

As of September 30, 2014, the FirstEnergy pension plan assets were allocated approximately as follows: 38% in equity securities, 36% in fixed income securities, 15% in absolute return strategies, 6% in real estate and 5% in cash and short-term securities. A decline in the value of pension plan assets could result in additional funding requirements. FirstEnergy’s funding policy is based on actuarial computations using the projected unit credit method. During the nine months ended September 30, 2014, FirstEnergy made no contributions to its qualified pension plans. See Note 4, Pensions and Other Postemployment Benefits, of the Combined Notes to Consolidated Financial Statements for additional details on FirstEnergy's pension plans and OPEB. Through September 30, 2014, FirstEnergy's pension plan assets earned approximately 5.5% as compared to an annual 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 September 30, 2014, approximately 65% of the funds were invested in fixed income securities, 30% of the funds were invested in equity securities and 5% 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 $1,577 million, $710 million and $123 million for fixed income securities, equity securities and short-term investments, respectively, as of September 30, 2014, excluding $(45) million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $71 million reduction in fair value as of September 30, 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 the nine months ended September 30, 2014, $8 million in contributions were made to the NDT.

Interest Rate Risk

FirstEnergy recognizes net actuarial gains or losses for its pension and OPEB plans in the fourth quarter of each fiscal year. A primary factor contributing to these actuarial gains and losses are changes in the discount rates used to value pension and OPEB obligations as of the measurement date of December 31 and the difference between expected and actual returns on the plans' assets. While FirstEnergy is unable to determine or project the mark-to-market adjustment that may be recorded as of December 31, 2014, based on current market indications and interest rates FirstEnergy would anticipate a pre-tax mark-to-market loss (net of amounts capitalized) to be in the range of approximately $550 million to $750 million assuming a discount rate of approximately 4.50% to 4.25%, respectively, an assumed expected annual return on plan assets of 7.75%, and lower mortality rates.

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 specified collateral requirements and use standardized agreements that facilitate the netting of cash flows. FirstEnergy monitors the financial conditions of existing counterparties on an ongoing basis. An independent risk management group oversees credit risk.

Wholesale Credit Risk

FirstEnergy 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 set-off. 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 and covered 2009-2011, the first three years of the statutory period. Expenditures were originally estimated to be approximately $101 million for the PE programs for the entire period of 2009-2015. PE's plan for the second three year period, 2012-2014, included additional and improved programs, and was approved by the MDPSC in December 2011. PE filed its third plan, covering the three-year period 2015-2017, on September 2, 2014. The projected costs of the 2015-2017 plan are approximately $64 million for that three year period. The MDPSC held hearings for the utilities' 2015-2017 plans on October 20-24, 2014. 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.

Pursuant to a bill passed by the Maryland legislature in 2011, 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. PE has advised the MDPSC that compliance with the new rules is expected to increase costs by approximately $106 million over the period 2012-2015. On April 1, 2013, the Maryland electric utilities, including PE, filed their first annual reports on compliance with the new rules, and following a hearing, the MDPSC issued an order on September 3, 2013, which accepted PE's filing and the operational changes proposed therein. PE filed its second annual report on March 27, 2014. The MDPSC held a hearing on the utility reports on July 10, 2014, and on August 27, 2014, the MDPSC issued an order accepting PE's second report.

Following a "derecho" storm through the region on June 29, 2012, the MDPSC convened a proceeding to consider matters relating to the electric utilities' performance in responding to the storm. Hearings on the matter were conducted in September 2012. Concurrently, Maryland's governor convened a special panel to examine possible ways to improve the resilience of the electric distribution system. On October 3, 2012, that panel issued a report calling for various measures including: acceleration and expansion of some of the requirements contained in the reliability standards which had become final on May 28, 2012; selective increased investment in system hardening; creation of separate recovery mechanisms for the costs of those changes and investments; and penalties or bonuses on returns earned by the utilities based on their reliability performance. On February 27, 2013, the MDPSC issued an order (the February 27 Order) requiring the utilities to submit several reports over a series of months, 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 responded to the requirements in the order consistent with the schedule set forth therein. 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 a written Order issued July 31, 2012, the NJBPU found that a base rate proceeding "will assure that JCP&L's rates are just and reasonable and that JCP&L is investing sufficiently to assure the provision of safe, adequate and proper utility service to its customers" and ordered JCP&L to file a base rate case using a historical 2011 test year. The rate case petition was filed on November 30, 2012 by JCP&L requesting approval to increase revenues by approximately $31 million, which included the recovery of 2011 storm costs but excluded approximately $603 million of costs incurred in 2012 associated with the impact of Hurricane Sandy. The NJBPU transmitted the case to the New Jersey Office of Administrative Law for further proceedings and an ALJ was assigned. Hearings in the rate case concluded in November 2013. In the initial briefs of the parties filed on January 27, 2014, 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). Reply briefs were filed on February 24, 2014. 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, and the matter is pending before the ALJ. On July 24, 2014, the Division of Rate Counsel filed a motion with the NJBPU requesting that effective August 1, 2014, JCP&L's existing rates be continued on a provisional basis until the NJBPU's final order in the base rate case and subject to refund. JCP&L filed a brief opposing the motion on August 4, 2014, and the Division of Rate Counsel filed a reply to JCP&L's opposition on August 8, 2014. On September 30, 2014, the NJBPU granted the request of the ALJ to extend the time for an initial decision in the base rate case until November 13, 2014.

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 on August 18, 2014. 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. Although FirstEnergy is still reviewing the CTA Order, by our interpretation and calculation, FirstEnergy expects that application of the modified policy in the pending JCP&L base rate case would reduce the CTA revenue adjustment as proposed by certain parties to the case from approximately $56 million to approximately $5 to $6 million.

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 in the May 31 clarification 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, consistent with NJBPU's orders, JCP&L filed the 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) in the fourth quarter of 2013. By its Order of March 19, 2014, the NJBPU approved the Stipulation of Settlement and on March 25, 2014, transmitted a copy of that Order to the Office of Administrative Law so that “actual recovery of the

2011 costs can be determined in relation to the pending base rate case." Recovery of 2011 storm costs will be addressed in the pending base rate case and are included in JCP&L's May 5, 2014, proposed rate increase; while recovery of 2012 storm costs 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 existing 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 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 to the Supreme Court of Ohio were filed by the Northeast Ohio Public Energy Council and the ELPC. While briefing has been completed, the matter has not yet been scheduled for oral argument. Northeast Ohio Public Energy Council and the ELPC filed a motion to expedite the oral argument on August 28, 2014. The Ohio Companies responded opposing the motion on September 8, 2014. On October 8, 2014, the Supreme Court of Ohio denied the Northeast Ohio Public Energy Council and ELPC's motion to expedite the 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 evidentiary hearing on the ESP IV is currently scheduled to commence January 20, 2015. The material terms of the proposed plan include:

- Continuing a base distribution rate freeze through May 31, 2019;
- Continues 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 R.C. 4928.66 (codification of SB221), and the Ohio Companies' filing of amended energy efficiency plans under SB310, the Ohio Companies are required to implement energy efficiency programs that achieve a total annual energy savings equivalent of approximately 1,200 GWHs in 2012, 1,705 GWHs in 2013, and 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. The Ohio Companies filed annual status reports in 2013 and 2014 indicating their compliance with the statutory energy efficiency and peak demand reduction benchmarks in 2012 and 2013, respectively.

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 bidding energy efficiency and demand response 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 under the basis that the PUCO's authorization for the Ohio Companies to share in the PJM revenues was unlawful. The PUCO granted rehearing on September 11, 2013 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. The PUCO has sixty days to review and approve, or modify and approve, the amended plan.

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. The Ohio Companies' response was filed on November 4, 2013. The motion is still pending and additional briefing has followed. While briefing has been completed, the matter has not been scheduled for oral argument.

R.C. 4928.64 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 the renewable energy requirements established under SB221. 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 and selected auditors to perform a financial and management audit. Final audit reports filed with the PUCO generally supported the Ohio Companies' approach to procurement of RECs, but also recommended the PUCO examine, for possible disallowance, certain costs associated with the procurement of in-state renewable obligations that the auditor characterized as excessive. Following the hearing, 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, and to file tariff schedules reflecting the refund and interest costs within 60 days following the issuance of a final appealable order on the basis that the Ohio Companies did not prove such purchases were prudent. The Ohio Companies, along with other parties, timely filed applications for rehearing on September 6, 2013. On December 18, 2013, the PUCO denied all of the applications for rehearing. 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, the Ohio Companies filed a notice of appeal and a motion for stay of the PUCO's order with the Supreme Court of Ohio. On February 10, 2014, the Supreme Court of Ohio granted the Ohio Companies' motion for stay, which went into effect on February 14, 2014. 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. On April 15, 2014, the Supreme Court of Ohio stayed the briefing schedule pending the court's resolution of the Ohio Companies' motion to seal certain confidential portions of the appendix and supplement to their merit brief. On May 6, 2014, the PUCO issued an Entry extending the confidential treatment to February 13, 2015, of all materials and information previously granted confidential treatment. On September 3, 2014, the Supreme Court of Ohio ruled that the documents filed under seal will be maintained under seal pursuant to Supreme Court rules, and that the briefing schedule should recommence.

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. While approving the settlement, the PPUC, however, also denied the Pennsylvania Companies' proposal to recover NITS on a non-bypassable basis.

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 a 29-month period that began in January of 2011. 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. The balance of marginal transmission losses was fully refunded to customers by the second quarter of 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. One judge dissented, writing that the Pennsylvania authorities improperly interpreted a matter outside of their jurisdiction and that was in FERC's exclusive jurisdiction (the PJM tariff meaning of line losses), and that preclusion therefore does not apply. 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 are evaluating next steps, including a possible appeal to the U.S. Supreme Court.

Pennsylvania adopted Act 129 in 2008 to address issues such as: energy efficiency and peak load reduction; generation procurement; time-of-use rates; smart meters; and alternative energy. Among other things, Act 129 required utilities to file with the PPUC an energy efficiency and peak load reduction plan (EE&C Plan) by July 1, 2009, setting forth the utilities' plans to reduce energy consumption by a minimum of 1% and 3% by May 31, 2011 and May 31, 2013, respectively, and to reduce peak demand by a minimum of 4.5% by May 31, 2013. Act 129 provides for potentially significant financial penalties between $1 and $20 million to be assessed on utilities that fail to achieve the required reductions in consumption and peak demand. The Pennsylvania Companies submitted reports in November 2011 and November 2013, in which they reported on their compliance with the statutory benchmarks. On March 20, 2014, the PPUC issued an Order initially determining that ME, PN and Penn achieved the 2011 and 2013 statutory energy efficiency benchmarks and that WP was in compliance with the 2013 statutory energy efficiency and peak demand benchmarks but was not in compliance with the 2011 energy efficiency benchmarks. The PPUC referred the matter of WP's compliance with the 2011 statutory benchmarks, to the PPUC Bureau of Investigation and Enforcement for the initiation of an appropriate proceeding by May 30, 2014 to investigate whether WP is subject to statutory penalties. The initial determination would be deemed final unless any petitions challenging its initial determination were filed within 20 days of the Order. On April 9, 2014, WP filed a petition challenging the PPUC’s initial determination arguing, among other things, that the May 2011 target was not mandatory and WP was in compliance because it achieved its May 2013 targets. On April 21, 2014, WP filed an appeal with the Commonwealth Court of Pennsylvania challenging the PPUC's initial finding of a violation of Act 129 on due process grounds. The Bureau of Investigation and Enforcement also initiated a proceeding by filing a Complaint against WP in which it alleged that WP violated Act 129 and recommended a penalty in the amount of $11.4 million. On August 22, 2014, the PPUC entered an Order approving a joint petition for settlement filed on July 30, 2014, that resolved all issues in the pending proceedings, and included WP making a payment of $1.3 million to the PPUC. On September 9, 2014, WP submitted the $1.3 million payment to the PPUC and withdrew the Commonwealth Court appeal and the petition before the PPUC challenging its initial findings thereby concluding these matters.

Pursuant to Act 129, the PPUC was charged with reviewing the cost effectiveness of energy efficiency and peak demand reduction programs. The PPUC found the energy efficiency programs to be cost effective and 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 until it receives more information from the EE&C statewide evaluator, and therefore 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 also 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.

In the PPUC Order approving the FirstEnergy and AE merger, the PPUC announced that a separate statewide investigation into Pennsylvania's retail electricity market would be conducted with the goal of making recommendations for improvements to ensure that a properly functioning and workable competitive retail electricity market exists in the state. On April 29, 2011, the PPUC entered an Order initiating the investigation and requesting comments from interested parties on eleven directed questions concerning retail markets in Pennsylvania to investigate both intermediate and long term plans that could be adopted to further foster the competitive markets, and to explore the future of default service in Pennsylvania following the expiration of the upcoming DSPs on May 31, 2015. A final order was issued on February 15, 2013, providing recommendations on the entities to provide default service, the products to be offered, billing options, customer education, and licensing fees and assessments, among other items. Subsequently, the PPUC established five workgroups and one comment proceeding in order to seek resolution of certain matters and to clarify certain obligations that arose from that order.

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. The filings also propose several new cost recovery riders as well as revisions to certain existing cost recovery riders. An order on the proposed increases is expected in May 2015.

WEST VIRGINIA

MP and PE currently operate under a Joint Stipulation and Agreement of Settlement reached with the other parties and approved by the WVPSC in June 2010 that provided for:

- $40 million annualized base rate increases effective June 29, 2010;
- Deferral of February 2010 storm restoration expenses over a maximum five-year period;
- Additional $20 million annualized base rate increase effective in January 2011;

- Decrease of $20 million in ENEC rates effective January 2011, providing for deferral of related costs for later recovery in 2012; and
- Moratorium on filing for further increases in base rates before December 1, 2011, except under specified circumstances.

On April 30, 2014, MP and PE filed a rate case requesting a base rate increase of approximately $96 million, or 9.3%, based on an historic 2013 test year. The filing also included a surcharge to recover costs of MP's and PE's vegetation management program in the amount of approximately $48 million. On June 13, 2014, MP and PE amended their filing to add an additional $7.5 million of additional revenues to reimburse their expected costs of implementing monthly meter reading for residential and small commercial customers, resulting in a proposed total rate increase request of approximately $152 million, or 14.7%. On November 3, 2014, a Joint Stipulation was submitted by all parties which resolves all issues in the pending proceeding and 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 operating and maintenance expenses and capital costs related to a new vegetation maintenance program; authority to establish a regulatory asset for MATS investments placed into service in 2016 and 2017 and recover in the next base rate case; authority to defer, amortize and recover over a 5-year period approximately $46 million of restoration costs associated with the 2012 Derecho and Hurricane Sandy storms; and elimination of the Temporary Transaction Surcharge and movement of the costs currently being collected for the 2013 Harrison generation transaction into base rates effective February 25, 2015. The settlement is subject to review and approval of the WVPSC. The WVPSC has scheduled a hearing for November 7, 2014, to evaluate the settlement and its terms.

On August 29, 2014, MP and PE filed their annual ENEC case proposing an approximate $65.8 million annual increase in rates, which is a 5.7% overall increase over existing rates. The $65.8 million 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. This proceeding includes a two-year review period as there was not an annual ENEC filing in 2013 pursuant to party agreement and WVPSC consent during MP and PE's 2013 proceeding authorizing the Harrison/Pleasants asset transfer. An order is expected to be issued before the end of 2014.

RELIABILITY MATTERS

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

FirstEnergy believes that it is in compliance with all currently-effective and enforceable reliability standards. Nevertheless, in the course of operating its extensive electric utility systems and facilities, FirstEnergy occasionally learns of isolated facts or circumstances that could be interpreted as excursions from the reliability standards. If and when such items are found, FirstEnergy develops information about the item and develops a remedial response to the specific circumstances, including in appropriate cases "self-reporting" an item to RFC. Moreover, it is clear that the NERC, RFC and FERC will continue to refine existing reliability standards as well as to develop and adopt new reliability standards. Any inability on FirstEnergy's part to comply with the reliability standards for its bulk power system could result in the imposition of financial penalties that could have a material adverse effect on its financial condition, results of operations and cash flows.

FERC MATTERS

PJM Transmission Rates

PJM and its stakeholders have been debating the proper method to allocate costs for new transmission facilities. While FirstEnergy and other parties advocated for a traditional "beneficiary pays" (or usage based) approach, others advocate for "socializing" the costs on a load-ratio share basis, 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 U.S. Court of Appeals for 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 by means of a "postage-stamp" rate. 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 them, and not based on load-ratio share in PJM as a whole. The court remanded the case to FERC for further proceedings to implement its findings and ruling. On September 5, 2014, the Seventh Circuit denied a petition for rehearing and rehearing en banc of the panel's decision.

Order No. 1000, issued by FERC on July 21, 2011, announced new policies regarding transmission planning and transmission cost allocation. Order No. 1000 required the submission of a compliance filing by PJM or the PJM transmission owners demonstrating that the cost allocation methodology for new transmission projects directed by the PJM Board of Managers satisfied the principles set forth in the order. On August 15, 2014 the D.C. Circuit affirmed

Order No. 1000 in every respect, including its termination of certain "right of first refusal" privileges discussed in more detail below. On October 17, 2014, the court denied a request for rehearing that had been filed by representatives of certain public power entities.

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 D.C. Circuit.

To demonstrate compliance with the regional cost allocation principles of Order No. 1000, the PJM transmission owners, including FirstEnergy, submitted a filing to FERC proposing a hybrid method of 50% beneficiary pays and 50% postage stamp to be effective for RTEP projects approved by the PJM Board of Managers on, and after, the effective date of the compliance filings. FERC approved the filing, subject to additional compliance filings. Requests for rehearing by certain parties remain pending. Separately, the PJM transmission owners, including FirstEnergy, submitted filings to FERC setting forth the cost allocation method for projects that cross the borders between: (1) the PJM region and the NYISO region; and (2) the PJM region and 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. On the same date, also in response to Order No. 1000, the PJM transmission owners, including FirstEnergy, also submitted to FERC a filing stating 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. On December 30, 2013, FERC conditionally accepted the PJM/SERTP cross-border project cost allocation filing, subject to refund and future orders in PJM's and the SERTP region participants' related Order No. 1000 interregional compliance proceedings. The PJM/NYISO and PJM/MISO cross-border project cost allocation filings remain 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. The move was performed as planned with no known operational or reliability issues for ATSI or for the wholesale transmission customers in the ATSI zone. While many of the matters involved with the move have been resolved, FERC denied recovery by means of 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 that demonstrates net benefits to customers from the move. On December 21, 2012, ATSI and other parties filed a proposed settlement agreement with FERC to resolve the exit fee and transmission cost allocation issues. However, FERC subsequently rejected that settlement, 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. On October 21, 2013, FirstEnergy filed a request for rehearing of FERC's order, which 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. A separate but related issue is the allocation of certain congestion revenue rights (described as "MISO LTTRs") that result from constructing MVP projects. Although MISO and the MISO transmission owners agree that the ATSI zone should pay for the Michigan Thumb MVP project, they submitted a proposed tariff that, among other things, would have the effect of depriving ATSI of ATSI’s share of the most valuable class of MISO LTTRs associated with that project. ATSI protested this proposal but, on September 18, 2014, FERC issued an order approving the MISO LTTR proposal. On October 20, 2014, ATSI requested rehearing of FERC’s September 18, 2014 order.

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 a 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. ATSI has requested FERC approval of the proposal with an effective date of January 1, 2015. FirstEnergy expects that FERC will issue an initial ruling by the end of 2014.

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 U.S. Court of Appeals for the Ninth Circuit in several pending proceedings to resolve all outstanding refund and other claims, including claims of alleged price manipulation in the California energy markets, during 2000 and 2001. The Ninth Circuit had previously remanded one of those proceedings to FERC, which dismissed the claims of the California Parties in May 2011, and affirmed the dismissal in June 2012. The California Parties appealed FERC's decision back to the Ninth Circuit, where the appeal remains pending.

In another proceeding, in June 2009, the California Attorney General, on behalf of certain California parties, filed another complaint with FERC against various sellers, including AE Supply, again seeking refunds for transactions in the California energy markets during 2000 and 2001. The above-noted transactions with CDWR are the basis for including AE Supply in this complaint. AE Supply filed a motion to dismiss, which was granted by FERC in May 2011, and affirmed by FERC in June 2012. The California Attorney General 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 it had suspended in February 2011. As a result, approximately $62 million and approximately $59 million in costs incurred by PATH-Allegheny and PATH-WV, respectively, were reclassified from net property, plant and equipment to a regulatory asset for future recovery. On September 28, 2012, those companies requested authorization from FERC to recover the costs with a proposed ROE of 10.9% (10.4% base plus 0.5% for RTO membership) from PJM customers over the next five years. Several parties protested the request. On November 30, 2012, FERC issued an order denying the 0.5% 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 procedures 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 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 suggesting that FERC order that the remaining concerns be addressed in the existing stakeholder process that is described in the PJM/MISO Joint Operating Agreement. FERC has not mandated a solution, and the RTOs and affected parties are working to address the MISO's proposal in stakeholder proceedings. Changes to the criteria and qualifications for participation in the PJM RPM capacity auctions could have a significant impact on the outcome of those auctions, including a negative impact on the prices at which those auctions would clear.

MOPR Reform

On May 2, 2013, FERC issued an order in large part accepting PJM's proposed reform of the MOPR, including two proposed categorical exemptions and applicability to existing resources, and also requiring PJM to commit to future review and, if necessary, additional revisions to the MOPR to accommodate changing market conditions. On June 3, 2013, FirstEnergy submitted a request for rehearing of FERC's May 2, 2013 order. In its rehearing request, FirstEnergy referenced the results of the May 2013 PJM RPM capacity auction, and publicly-available data about the reasons for the unexpectedly low "rest-of-RTO" clearing price of $59 per MW-day, as supporting its contention that the MOPR reform depressed prices as predicted in FirstEnergy's December 28, 2012 and January 25, 2013 comments. FirstEnergy's request for rehearing is pending before FERC.

FTR Underfunding Complaint

In PJM, FTRs are a mechanism to hedge congestion and they 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. Various parties filed responsive pleadings, including PJM. On June 5, 2013, FERC issued its order denying the new complaint. On July 5, 2013, FESC, on behalf of FES and AE Supply, filed a request for rehearing of FERC's order. That request for rehearing, and all subsequent filings in the docket, are pending before FERC. The PJM stakeholders continue to discuss the problem of 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. On September 29, 2014, FESC, on behalf of certain of its affiliates, filed comments supporting the investigation, arguing that tariff changes would decrease the incidence of Up-to Congestion transactions, and funding for FTRs likely would increase.

2013-2014 PJM RPM Tariff Amendments

In November 2013, PJM began to submit a series of amendments to its RPM capacity tariff in order to address certain problems that have been observed in recent auctions. These problems 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. The purpose of PJM’s tariff amendments is 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. In each of the relevant dockets, FirstEnergy and other parties submitted comments largely supporting PJM's proposed amendments. FERC largely approved the 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, and a technical conference announced by FERC regarding the arbitrage/capacity replacement issue has yet to be scheduled.

On August 20, 2014, PJM announced that it is contemplating major revisions to its RPM program for the purpose of addressing issues that were identified in the January 2014 polar vortex. On October 7, 2014, PJM released a document that describes its proposed revisions. Highlights of the proposed revisions include: (i) classifying capacity into two products, Base Capacity and Capacity Performance, and capping the amount of Base Capacity that would be procured; (ii) allowing all Capacity Performance units to offer at the Net Cost-of-New-Entry (Net CONE); (iii) eliminating the “2.5% holdback” in the BRA; (iv) imposing significant new penalties on Performance Capacity units that fail to operate when called by PJM; and (v) suggesting a mechanism to limit price change year-over-year between RPM auctions. PJM expects that these changes will increase the RPM auction clearing prices by a significant amount. FirstEnergy is participating in the stakeholder processes where these PJM proposals are being developed. PJM has announced its plans to file tariff revisions that implement some version of these proposed revisions in time for the May 2015 BRA.

PJM RPM Auctions - Calculation of Unit-Specific Offer Caps

The PJM RPM capacity tariff describes the rules for calculating the “offer cap” for each unit that offers into the RPM auctions. In summary, the offer cap is calculated by identifying certain going-forward costs, including the going-forward capital requirements, for a given unit, and then subtracting the projected energy and ancillary services revenues, net of marginal costs, from the going-forward costs. The remainder becomes the offer cap. FES disagreed with the Market Monitor's approach for calculating the offer caps, and earlier in 2014, FES asked FERC to determine which tariff interpretation, FES or the 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. FERC directed PJM to file a brief by November 3, 2014 explaining why the existing tariff language is just and reasonable, and that responsive briefs are due thirty days after PJM files its brief.

PJM Market Reform: FERC Order No. 745 - Demand Response

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, just as if DR were a traditional energy resource. The majority concluded that DR is a retail service, and therefore falls under state, and not federal, jurisdiction, and that FERC therefore lacked jurisdiction to regulate DR, such as via the PJM tariffs and programs. 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 receiving a double payment (LMP plus the savings of foregone energy purchases). On September 17, 2014, the U.S. Court of Appeals for the D.C. Circuit denied FERC's request for review of the May 23, 2014 D.C. Circuit Panel's decision on Order No. 745. On October 20, 2014, and in response to a motion by FERC, the U.S. Court of Appeals for the D.C. Circuit "stayed" issuance of its mandate until December 16, 2014, pending potential appeal by FERC to the U.S. Supreme Court.

On May 23, 2014, FESC, on behalf of FE entities with market-based rate authority, filed a complaint asking FERC to direct PJM to remove all portions of the PJM OATT, which allow or require PJM to include DR in the PJM capacity market, and to invalidate the results of the May 2014 RPM capacity auction on the grounds that the U.S. Court of Appeals for the D.C. Circuit’s May 23, 2014 decision required removal of DR from the wholesale capacity markets. FESC filed an amended complaint on September 22, 2014, renewing its request that DR be removed from the May 2014 BRA. On October 22, 2014, PJM filed its answer to the complaint. Various other parties also filed comments on and protests of the amended complaint. The timing of FERC action and the outcome of this proceeding cannot be predicted at this time.

PJM RPM, 2014 Triennial Review

PJM’s tariff obligates it to perform a thorough review of its RPM program every three years. PJM’s usual practice is to work through the stakeholder process to retain a consultant to perform a study. PJM and the stakeholders then review the study results, and incremental changes to the tariff then are filed at FERC. PJM's consultant recently completed the 2014 triennial review and, on September 25, 2014, PJM filed proposed changes to the RPM tariff, purportedly in response to the consultant's study results. Highlights of the September 25, 2014 filing include shifting the VRR curve one percentage point to the right, which, if accepted by FERC, will have the effect of increasing the amount of capacity supply that is procured in the RPM auctions and increasing the clearing price. Another highlight is a proposed change of the index that is used for calculating the generation plant construction costs of the Net Cost-of-New-Entry formula for the future years between triennial reviews. On October 16, 2014, FirstEnergy, as part of a coalition, filed comments supporting the proposal to move the VRR curve, but protesting the proposal to revise the index. This matter is pending before FERC.

Market-Based Rate Authority, Triennial Update

OE, CEI, TE, Penn, JCP&L, ME, PN, MP, WP, PE, 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 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.

TrAIL, Petition for Authorization to Pay Dividends

On October 7, 2014, TrAIL filed a petition with FERC requesting authorization to declare and pay periodic dividends out of paid-in-capital from time to time on an as-needed basis to maintain its capital structure within the range of capital structures approved by FERC for transmission-owning investor-owned utilities. This authorization will provide flexibility to TrAIL to maintain its capital structure without having to issue new long-term debt.

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 RTO 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.

In August 2000, AE received an information request pursuant to section 114(a) of the CAA from the EPA requesting that it provide information and documentation relevant to the operation and maintenance of the following ten coal-fired plants, which collectively include 22 electric generation units: Albright, Armstrong, Fort Martin, Harrison, Hatfield's Ferry, Mitchell, Pleasants, Rivesville, R. Paul Smith and Willow Island to determine compliance with the NSR provisions under the CAA, which can require the installation of additional air emission control equipment when a major modification of an existing facility results in an increase in emissions. In September 2007, AE received 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. On June 29, 2012, January 31, 2013, and March 27, 2013, EPA issued additional CAA section 114 requests for the Harrison coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2007. 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 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. A non-jury trial on liability only was held in September 2010. 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. On March 10, 2014, New York, Connecticut, and Maryland filed an appeal with the U.S. Court of Appeals for the Third Circuit. This decision does not change the status of these plants which remain deactivated.

In July 2008, three complaints representing multiple plaintiffs were filed against FG in the U.S. District Court for the Western District of Pennsylvania seeking damages based on air emissions from the coal-fired Bruce Mansfield Plant. Two of these complaints also seek to enjoin the Bruce Mansfield Plant from operating except in a “safe, responsible, prudent and proper manner.” One complaint was filed on behalf of twenty-one individuals and the other is a class action complaint seeking certification as a class with the eight named plaintiffs as the class representatives. FG believes the claims are without merit and intends to vigorously defend itself against the allegations made in these complaints, but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In January 2009, the EPA issued an NOV to GenOn Energy, Inc. alleging NSR violations at the Keystone, Portland and Shawville coal-fired plants based on “modifications” dating back to the mid-1980s. JCP&L, as the former owner of 16.67% of the Keystone Station, ME, as a former owner and operator of the Portland Station, and PN as former owner and operator of the Shawville Station, are unable to predict the outcome of this matter or estimate the possible loss or range of loss.

In August 2009, the EPA issued a Finding of Violation and NOV alleging violations of the CAA and Ohio regulations, including the PSD, NNSR and Title V regulations, at the Eastlake, Lakeshore, Bay Shore and Ashtabula coal-fired plants. The EPA's NOV alleges equipment replacements during maintenance outages dating back to 1990 triggered the pre-construction permitting requirements under the PSD and NNSR programs. In June 2011, EPA issued another Finding of Violation and NOV alleging violations of the CAA and Ohio regulations, specifically, opacity limitations and requirements to continuously operate opacity monitoring systems at the Eastlake, Lakeshore, Bay Shore and Ashtabula coal-fired plants. FG intends to comply with the CAA and Ohio regulations, but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

National Ambient Air Quality Standards

The EPA's CAIR requires reductions of NOx and SO_2 emissions in two phases (2009/2010 and 2015), ultimately capping SO_2 emissions in affected states to 2.5 million tons annually and NOx emissions to 1.3 million tons annually. In 2008, the U.S. Court of Appeals for the 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 replaces CAIR with a new rule consistent with the Court's decision. In July 2011, the EPA finalized CSAPR, to replace CAIR, requiring reductions of NOx and SO_2 emissions in two phases (2012 and 2014), ultimately capping SO_2 emissions in affected states to 2.4 million tons annually and NOx emissions to 1.2 million tons annually. CSAPR allows trading of NOx and SO_2 emission allowances between power plants located in the same state and interstate trading of NOx and SO_2 emission allowances with some restrictions. On December 30, 2011, CSAPR was stayed by the U.S. Court of Appeals for the D.C. Circuit and was ultimately vacated by the Court on August 21, 2012. The Court has ordered the EPA to continue administration of CAIR until it finalizes a valid replacement for CAIR. On April 29, 2014, the U.S. Supreme Court reversed 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 D.C. Circuit lifted its stay of CSAPR allowing its Phase 1 reductions of NOx and SO_2 emissions to begin in 2015, a 3 year delay from EPA's original rule. CSAPR Phase 2 will also be delayed by 3 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.

Hazardous Air Pollutant Emissions

On December 21, 2011, the EPA finalized the MATS imposing emission limits for mercury, PM, and HCL for all existing and new coal-fired electric generating units effective in April 2015 with averaging of emissions from multiple units located at a single plant. Under the CAA, state permitting authorities can grant an additional compliance year through April 2016, as needed, including instances when necessary to maintain reliability where electric generating units are being closed. On December 28, 2012, the WVDEP granted a conditional 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 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 July 14, 2014, various entities filed a petition seeking further review by the U.S. Supreme Court. Depending on the outcome of further appeals, if any, and how the MATS are ultimately implemented, FirstEnergy's total cost of compliance with MATS is currently estimated to be approximately $370 million (Competitive Energy Services segment of $178 million and Regulated Distribution segment of $192 million), reduced from the previous estimate of $465 million.

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 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 two agreements, FE and FES have agreed to pay liquidated damages for delivery shortfalls for 2014. If FE and FES fail to reach a resolution with applicable counterparties for coal transportation agreements associated with the deactivated plants or unresolved aspects of the transportation agreements and it were ultimately determined that, contrary to their belief, the force majeure provisions or other defenses do not excuse 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. 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.

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 to reduce GHG emissions, such as demand reduction programs, renewable portfolio standards and renewable subsidies have been implemented across the nation. In his 2013 State of the Union address, President Obama called for Congressional action on GHG emissions indicating his administration will take executive action in the event Congress does not pass climate legislation that he supports. To date, Congress has not passed the President's GHG cap and trade proposal. In June 2013, the President's 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. 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.

In September 2009, the EPA finalized a national GHG emissions collection and reporting rule that required the measurement and reporting of GHG emissions commencing in 2010. In December 2009, the EPA released its final “Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act.” The EPA's finding concludes that concentrations of several key GHGs constitutes an "endangerment" and may be regulated as “air pollutants” under the CAA. In April 2010, the EPA finalized new GHG standards for model years 2012 to 2016 passenger cars, light-duty trucks and medium-duty passenger vehicles and clarified that GHG regulation under the CAA would not be triggered for electric generating plants and other stationary sources until January 2, 2011, at the earliest. In May 2010, the EPA finalized new thresholds for GHG emissions that define when NSR pre-construction permits would be required including an emissions applicability threshold of 75,000 tons per year of CO_2 equivalents for existing facilities under the CAA's PSD program. On April 13, 2012, the EPA proposed new source performance standards for GHG emissions from newly constructed fossil fuel generating units that are larger than 25 MW, which were ultimately withdrawn. On June 25, 2013, a Presidential memorandum directed the EPA to complete, in a timely fashion, proposed new source performance standards for GHG emissions from newly constructed fossil fuel generating units, starting with re-proposal by September 20, 2013. The memorandum further directed the EPA to propose by June 1, 2014 and complete by June 1, 2015, GHG emission standards for existing fossil fuel electric generating units. On September 20, 2013, the EPA proposed a new source performance standard, 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. On June 2, 2014, the EPA proposed regulations to reduce CO_2 emissions from existing fossil fuel electric generating units that would require each state to develop implementation plans by June 30, 2016, to meet EPA’s state specific emission rate goals. EPA’s proposal allows states to request a 1-year extension for single-state implementation plans (June 30, 2017) or a 2-year extension for multi-state implementation plans (June 30, 2018). EPA also proposed separate regulations imposing additional CO_2 emission limits on modified and reconstructed fossil fuel electric generating units. On October 15, 2013, the U.S. Supreme Court agreed to review a June 2012 U.S. Court of Appeals for the D.C. Circuit decision upholding the EPA's May 2010 regulations to decide a single narrow question: "Whether EPA permissibly determined that its regulation of greenhouse gas emissions from new motor vehicles triggered permitting requirements under the CAA for stationary sources that emit greenhouse gases?" On June 23, 2014, the U.S. Supreme Court decided that CO_2 or other greenhouse gas 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 greenhouse gas control technologies. Depending on how any final rules are ultimately implemented, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

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.

In 2004, the EPA established new performance standards under Section 316(b) of the CWA for reducing impacts on fish and shellfish from cooling water intake structures at certain existing electric generating plants. The regulations call for reductions in impingement mortality (when aquatic organisms are pinned against screens or other parts of a cooling water intake system) and entrainment (which occurs when aquatic life is drawn into a facility's cooling water system). In 2007, the U.S. Court of Appeals for the Second Circuit invalidated portions of the Section 316(b) performance standards and the EPA has taken the position that until further rulemaking occurs, permitting authorities should continue the existing practice of applying their best professional judgment to minimize impacts on fish and shellfish from cooling water intake structures. In April 2009, the U.S. Supreme Court reversed one significant aspect of the Second Circuit's opinion and decided that Section 316(b) of the CWA authorizes the EPA to compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. On March 28, 2011, the EPA released a new proposed regulation under Section 316(b) of the CWA to reduce fish impingement to a 12% annual average and determine site-specific controls, if any, to reduce entrainment of aquatic life following studies to be provided to permitting authorities. On May 19, 2014, the EPA finalized Section 316(b) regulations requiring cooling water intake structures with an intake velocity greater than 0.5 feet per second to reduce fish impingement to a 12% annual average and determine site-specific controls, if any, to reduce entrainment of aquatic life following studies by cooling water intake structures exceeding 125 million gallons per day. 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 water intake system. Depending on the results of such studies and any final action taken by the states exercising best professional judgment, the future costs of compliance with these standards may require material capital expenditures.

On April 19, 2013, the EPA proposed regulatory changes to the waste water effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423). 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 waste water discharge permits are renewed on a 5-year cycle from 2017 to 2022. Depending on the content of the EPA's final rule, 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 submitted its CWA 303(d) list to the EPA with a recommended sulfate impairment designation for an approximately 68 mile stretch of the Monongahela River north of the West Virginia border. In May 2011, the EPA agreed with PA DEP's recommended sulfate impairment designation which requires the development of a TMDL limit for the river, a process that will take PA DEP approximately five years. Based on the stringency of the TMDL, MP may incur significant costs to reduce sulfate discharges into the Monongahela River if the NPDES permit for the coal-fired Fort Martin plant in West Virginia is required to be modified or renewed to include more stringent effluent limitations for sulfate. However, the Hatfield's Ferry and Mitchell Plants in Pennsylvania that discharge into the Monongahela River were deactivated on October 9, 2013. On April 21, 2014, PA DEP recommended that the sulfate impairment designation for the Monongahela River be removed in its bi-annual water report. A 45-day public comment period ended on June 10, 2014, and PA DEP must obtain EPA approval to remove the sulfate impairment designation which would eliminate the need to develop a TMDL.

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 fossil-fuel combustion residuals, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation.

In December 2009, in an advance notice of public rulemaking, the EPA asserted that the large volumes of CCRs produced by electric utilities pose significant financial risk to the industry. In May 2010, the EPA proposed two options for additional regulation of CCRs, including the option of regulation as a special waste under the EPA's hazardous waste management program which could have a significant impact on the management, beneficial use and disposal of CCRs. On April 19, 2013, the EPA stated it would "align" its proposed CCR regulations with revised waste water discharge effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423) that were proposed on that date. On July 25, 2013, the House of Representatives passed H.R. 221 that would require CCRs to be regulated under Subtitle D of RCRA, as non-hazardous. On

January 29, 2014, EPA agreed to take final action by December 19, 2014 on whether or not to pursue the proposed non-hazardous waste option for regulating CCRs in a consent decree entered by a U.S. District Court. Depending on the content of the EPA's final effluent limitations rule, the specifics of any "alignment", whether EPA chooses to pursue the non-hazardous or hazardous waste option and the potential enactment of legislation, the future costs of compliance with such standards may require material capital expenditures.

On July 27, 2012, the PA DEP filed a complaint against FG in the U.S. District Court for the Western District of Pennsylvania with claims under the RCRA and Pennsylvania's Solid Waste Management Act regarding the LBR CCB Impoundment and simultaneously proposed a consent decree between PA DEP and FG to resolve those claims. On December 14, 2012, a modified consent decree that addresses public comments received by PA DEP was entered by the court, requiring FG to conduct monitoring studies and submit a closure plan to the PA DEP, no later than March 31, 2013, and discontinue disposal to LBR as currently permitted by December 31, 2016. The modified consent decree also required payment of civil penalties of $800,000 to resolve claims under the Solid Waste Management Act. On December 20, 2012, the Environmental Integrity Project and others served FG with a citizen suit notice alleging CWA and PA Clean Streams Law Violations at LBR. On February 1, 2013, FG submitted a feasibility study analyzing various technical issues relevant to the closure of LBR. On March 28, 2013, FG submitted to the PA DEP a Closure Plan Major Permit Modification Application which provides for placing a final cap over LBR that would require 15 years to fully implement following the closure of LBR. The estimated cost for the proposed closure plan is $234 million, including environmental and other post closure costs. On October 3, 2013, the PA DEP issued a technical deficiency letter citing four main deficiencies with the closure plan: (1) seeking to accelerate the 15 year period proposed by FG for closure activities to complete closure in 9 years by commencing closure activities prior to 2017 as proposed by FG; (2) seeking to extend bond closure and post closure activities beyond the 45 years proposed by FG; (3) seeking active dewatering of the CCBs in areas where there are seeps impacted by the Impoundment; and (4) seeking an abatement plan for groundwater impacted by arsenic. FG responded to the PA DEP on December 3, 2013, and as a result of the closure plan, FG increased its ARO for LBR by $163 million in 2013. On April 3, 2014, PA DEP issued a 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 CCBs, 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 CCBs following December 31, 2016, and on January 23, 2013, announced a plan for beneficial use of its CCBs for mine reclamation in LaBelle, Pennsylvania. In June 2013, a complaint filed in the U.S. District Court for the Western District of Pennsylvania, against the owner and operator of that mine, 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.

Lawsuits initially filed on October 10, 2013 and December 5, 2013, are pending against FG involving approximately 61 individuals in the U.S. District Court for the Northern District of West Virginia and approximately 26 individuals (16 of which have settled their claims) in the U.S. District Court for the Western District of Pennsylvania seeking damages for alleged property damage, bodily injury and emotional distress related to the LBR CCB 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.

FirstEnergy's future cost of compliance with any CCR regulations that may be promulgated could be substantial and would depend, in part, on the regulatory action taken by the EPA and implementation by the EPA or the states. Compliance with those regulations could have an adverse impact on FirstEnergy's results of operations and financial condition.

Certain of FirstEnergy's utilities have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the CERCLA. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all potentially responsible parties for a particular site may be liable on a joint and several basis. Environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of September 30, 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 $117 million have been accrued through September 30, 2014. Included in the total are accrued liabilities of approximately $82 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 September 30, 2014, FirstEnergy had approximately $2.4 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 NDT fluctuate based on market conditions. If the value of the trusts decline by a material amount, FirstEnergy's obligation to fund the trusts may increase. Disruptions in the capital markets and their effects on particular businesses and the economy could also affect the values of the NDT. 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. A NRC ASLB granted a hearing on the Davis-Besse license renewal application to a group of Intervenors. On July 9, 2012, the Intervenors proposed a contention on the environmental impacts of spent fuel storage in the Davis-Besse license renewal proceeding. In an order dated August 7, 2012, the Commissioners stated that they would not issue final licensing decisions until they had appropriately addressed the challenges to the NRC Waste Confidence Decision and Temporary Storage Rule and all pending contentions on this topic should be held in abeyance. On August 26, 2014, the Commissioners issued an order, which lifted the suspension on issuing final licensing decisions, based on a final rule on waste confidence that was approved by the NRC on that date. On October 8, 2014, the ASLB dismissed the proposed contention on the environmental impacts of the temporary storage and ultimate disposal of spent nuclear fuel. On September 29, 2014, the Intervenors filed a new 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 recent rulemaking on waste confidence 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. The shield building is a 2 1/2-foot thick reinforced concrete structure that provides biological shielding, protection from natural phenomena including wind and tornadoes and additional shielding in the event of an accident. 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 admit a new contention based on FENOC's plans to manage the subsurface laminar cracking in the Davis-Besse shield building. On October 3, 2014, FENOC and the NRC Staff filed their opposition to the admission of this new contention.

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. Anker WV entered into a long term CSA with AE Supply and MP for the supply of coal to the Harrison generating facility. Prior to the time of trial, ICG was dismissed as a defendant by the Court. As a result of defendants' past and continued failure to supply the contracted coal, AE Supply and MP have incurred and will continue to incur significant additional costs for purchasing replacement coal. A non-jury trial was held from January 10, 2011 through February 1, 2011. At trial, AE Supply and MP presented evidence that they incurred in excess of $80 million in damages for replacement coal purchased through the end of 2010 and will incur additional damages in excess of $150 million for future shortfalls. Defendants primarily claimed their performance was excused by the force majeure clause in the CSA and presented evidence at trial that they could not provide the contracted yearly tonnage amounts. On May 2, 2011, the court entered a verdict in favor of AE Supply and MP for $104 million ($90 million in future damages and $14 million for past damages/interest). On August 25, 2011, the Allegheny County Court denied all Motions for Post-Trial relief and the May 2, 2011 verdict became final. On August 26, 2011, the defendants posted bond and filed a Notice of Appeal with the Superior Court. On August 13, 2012, the Superior Court affirmed the $14 million past damages award but vacated the $90 million future damages award. While the Superior Court found that defendants still owed future damages, it remanded the calculation of those damages back to the trial court. On August 27, 2012, AE Supply and MP filed an Application for Reargument En Banc with the Superior Court, which was denied on October 19, 2012. AE Supply and MP filed a Petition for Allowance of Appeal with the Pennsylvania Supreme Court on November 19, 2012. On July 2, 2013, the Petition for Allowance of Appeal was denied and in the second quarter of 2013 the final past damage award of $15.5 million (including interest) was recognized. The case was sent back to the trial court to recalculate the future damages only, and a multi-day hearing was held beginning May 13, 2014. A ruling is expected in the fourth quarter of 2014. In a related proceeding before the same court, ICG is appealing a ruling by the court that prohibited their reliance on a price re-opener clause to limit future damages.

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 10, 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.

NEW ACCOUNTING PRONOUNCEMENTS

In May 2014, the FASB issued ASU No. 2014-09, 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, ASU No. 2014-09 specifies the accounting for costs to obtain or fulfill a contract with a customer and expands disclosure requirements for revenue recognition. 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 to LS Power 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. FES is taking action to reduce its exposure to weather-sensitive loads, including maintaining competitive generation resources in excess of committed sales, eliminate load obligations that do not adequately cover risk premiums, pursue more certain revenue streams, and modify its hedging strategy to optimize risk management and market upside opportunities. As part of this, FES has eliminated future selling efforts in certain sales channels, such as mass market, medium commercial-industrial and select large commercial-industrial, 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 as was experienced in the first quarter of 2014. Going forward, FES will target 65 to 75 million MWHs of sales with a 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, 10 to 20 million MWHs in block wholesale sales and 10 to 20 million MWHs of spot wholesale sales. 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 demand response programs, as well as regulatory and legislative actions, such as MATS among other factors. FES attempts to mitigate the market risk inherent in its energy position by economically hedging its exposure and continuously monitoring various risk measurement metrics to ensure compliance with its risk management policies.

During the first quarter of 2014, FE completed a $500 million equity contribution to FES.

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

Results of Operations

For the first nine months of 2014, FES reported a net loss of $30 million compared to a net loss of $29 million for the same period of 2013.

Revenues -

Total revenues increased $147 million, in the first nine months of 2014, compared to the same period of 2013, primarily due to increased wholesale revenues and higher volumes associated with POLR and Structured Sales, partially offset by a decline in Direct sales volumes. Revenues were also impacted by higher unit prices compared to 2013 as a result of increased channel pricing and ancillary pass-through revenues associated with PJM expenses incurred in January 2014.

The increase in total revenues resulted from the following sources:

Revenues by Type of Service	Nine Months Ended September 30 2014	2013	Increase (Decrease)
	(In millions)		
Direct	$1,876	$2,162	$(286)
Governmental Aggregation	924	911	13
Mass Market	354	335	19
POLR and Structured	1,039	862	177
Wholesale	317	180	137
Transmission	168	98	70
Other	124	107	17
Total Revenues	$4,802	$4,655	$147

MWH Sales by Channel	Nine Months Ended September 30 2014	2013	Increase (Decrease)
	(In thousands)		
Direct	35,018	41,678	(16.0)%
Governmental Aggregation	15,413	15,975	(3.5)%
Mass Market	5,294	5,045	4.9%
POLR and Structured	21,068	16,780	25.6%
Total MWH Sales	76,793	79,478	(3.4)%

The following table summarizes the price and volume factors contributing to changes in revenues:

MWH Sales Channel:	Source of Change in Revenues Increase (Decrease) Sales Volumes	Prices	Financially Settled Contracts	Capacity Revenue	Total
	(In millions)				
Direct	$(346)	$60	$—	$—	$(286)
Governmental Aggregation	(32)	45	—	—	13
Mass Market	17	2	—	—	19
POLR and Structured Sales	210	(33)	—	—	177
Wholesale	—	—	71	66	137

FES has eliminated future selling efforts in certain sales channels, such as mass market, medium commercial-industrial and select large commercial-industrial (Direct sales channel), 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 as was experienced in the first quarter of 2014.The decrease in Direct revenues of $286 million resulted from lower sales volumes from commercial and industrial customers, partially offset by higher unit prices. The increase in Governmental Aggregation revenues of $13 million primarily reflects higher unit prices, partially offset by lower sales volumes. The increase in Mass Market of $19 million resulted from the acquisition of new customers prior to the repositioning of the segment and higher unit prices. The Direct, Governmental Aggregation and Mass Market customer base was 2.3 million as of September 30, 2014 compared to 2.7 million as of September 30, 2013, reflecting FES' efforts to reposition its sales portfolio to more effectively hedge its generation. Higher unit prices in Direct, Governmental Aggregation and Mass Market sales channels resulted from increased channel pricing primarily resulting from higher capacity rates. 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, 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. 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 revenue of approximately $33 million associated with commercial and industrial customers was recognized in the first quarter of 2014.

The increase in POLR and structured sales of $177 million was due to higher POLR and structured sales volumes. Lower structured unit prices were primarily due to market conditions related to extreme weather events in January 2014 that reduced the gains on various structured financial sales contracts, partially offset by higher POLR rates associated with recent auctions.

Wholesale revenues increased $137 million due to a $66 million increase in capacity revenue from higher capacity prices and higher net gains of $71 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.

Transmission revenue increased $70 million due to higher congestion revenue associated with market conditions related to extreme weather events in the first quarter 2014.

Other revenue increased $17 million primarily due to higher lease revenues from additional repurchased equity interests in affiliated sale and leasebacks since the first nine months of 2013. FES earns lease revenue associated with the equity interests it purchased.

Operating Expenses -

Total operating expenses increased by $477 million in the first nine months of 2014 compared to the same period of 2013.

The following table summarizes the factors contributing to the changes in fuel and purchased power costs in the first nine months of 2014 compared with the same period of 2013:

	Source of Change Increase (Decrease)				
Operating Expense	Volumes	Prices	Financially Settled Contracts	Capacity Expense	Total
	(In millions)				
Fossil Fuel	$(18)	$18	$(6)	$—	$(6)
Nuclear Fuel	(2)	(5)	—	—	(7)
Non-affiliated Purchased Power[1]	(72)	790	(425)	226	519
Affiliated Purchased Power	6	(1)	(203)	—	(198)

[1] Realized losses on financially settled wholesale sales contracts of $263 million resulting from higher market prices were netted in purchased power.

Fossil and nuclear fuel costs decreased $13 million primarily due to a decrease in settlement and termination costs related to coal and transportation contracts and a decrease in generation volumes. In the first nine months of 2014, a fuel supply agreement was terminated for approximately $67 million, while settlements associated with past damages on coal transportation contracts amounted to $73 million in the first nine months of 2013. A decrease in fossil and nuclear generation volumes resulting from an increase in outages in the first nine months of 2014 was partially offset by an overall increase in prices associated with increased peaking generation in the first quarter of 2014.

Non-affiliated purchased power costs increased $519 million due to increased prices ($790 million) and higher capacity expenses ($226 million), partially offset by gains on financially settled contracts ($425 million) and lower volumes ($72 million). The increase in rate was primarily a result of higher on-peak prices from market conditions related to extreme weather events in January 2014, partially offset by gains on financially settled contracts. Lower volumes was primarily due to decreased load requirements. The increase in capacity expense was the result of higher capacity rates.

Affiliated purchased power costs decreased $198 million primarily associated with net gains on financially settled contracts with AE Supply resulting from higher market prices in the first quarter of 2014.

Other operating expenses increased $171 million in the first nine months of 2014, compared to the same period of 2013 primarily due to the following:

- Fossil operating costs decreased $7 million primarily due to lower contractor, labor and materials and equipment costs as the amount of planned outages for the nine months ended September 2014 declined from the previous year.

- Nuclear operating costs increased $25 million as a result of higher contractor, materials and equipment costs associated with refueling outages. There were two refueling outages in the first nine months of 2014 as compared to one outage in the first nine months of 2013.

- Transmission expenses increased $87 million primarily due to higher operating reserve and market-based ancillary costs associated with market conditions related to extreme weather events in January 2014. These ancillary charges from PJM were for system reliability and a portion of which are able to be passed through to commercial and industrial customers. Additionally, effective June 1, 2013, network expenses associated with POLR sales in Pennsylvania became the responsibility of suppliers.

- Other operating expenses increased $66 million primarily due to an increase in mark-to-market expenses of $46 million on commodity contract positions, an impairment of deferred advertising costs associated with the elimination of future selling efforts in the mass market and medium commercial-industrial sales channels, partially offset by lower leasehold costs from the Ohio Companies and retail and marketing related costs.

Other Expense -

Total other expense decreased $151 million in the first nine months of 2014, compared to the same period of 2013, primarily due to the absence of a $97 million loss on debt redemptions in connection with senior notes that were repurchased in 2013, lower net interest expense of $17 million due to debt redemptions and lower OTTI and higher investment income of $61 million primarily on NDT investments, partially offset by lower miscellaneous income of $24 million due to the inclusion in the prior year of a $18 million pre-tax gain on the sale of property to a regulated affiliate.

Discontinued Operations -

Discontinued operations increased net income $102 million in the first nine months of 2014 compared to the same period of 2013 primarily due to a pre-tax gain of approximately $177 million associated with the sale of certain hydro assets described above.

Income Tax Benefits —

FES' effective tax rates from continuing operations for the nine months ended September 30, 2014 and 2013 was 39.4% and 30.6%, respectively. The increase in the effective tax rate on pre-tax losses is primarily due to an increase in losses from continuing operations in jurisdictions with higher tax rates, a benefit resulting from a reduction in state deferred tax liabilities associated with changes in apportionment factors, partially offset by valuation allowances on local NOL carryforwards recognized in 2014.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Market Risk Information" in Item 2 above.

ITEM 4. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

The management of FirstEnergy and FES, with the participation of each registrant's chief executive officer and chief financial officer, have reviewed and evaluated the effectiveness of the registrant's disclosure controls and procedures, as defined in the Securities Exchange Act of 1934, as amended, Rules 13a-15(e) and 15d-15(e), as of the end of the period covered by this report. Based on that evaluation, the chief executive officer and chief financial officer of FE and FES have concluded that their respective registrant's disclosure controls and procedures were effective as of the end of the period covered by this report.

(b) Changes in Internal Control over Financial Reporting

During the quarter ended September 30, 2014, there were no changes in internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, FE's and FES' internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Information required for Part II, Item 1 is incorporated by reference to the discussions in Note 10, Regulatory Matters, and Note 11, Commitments, Guarantees and Contingencies, of the Combined Notes to the Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q.

ITEM 1A. RISK FACTORS

During the quarter ended September 30, 2014, there were no material changes to the risk factors included in our Annual Report or Form 10-K for the year ended December 31, 2013 and the Form 10-Q for the quarter ended June 30, 2014.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable

ITEM 5. OTHER INFORMATION

None

ITEM 6. EXHIBITS

Exhibit Number

FirstEnergy

(A)	12	Fixed charge ratio
(A)	31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
(A)	31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
(A)	32	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350
	101	The following materials from the Quarterly Report on Form 10-Q of FirstEnergy Corp. for the period ended September 30, 2014, formatted in XBRL (Extensible Business Reporting Language): (i) Consolidated Statements of Income and Consolidated Statements of Comprehensive Income, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Cash Flows, (iv) related notes to these financial statements and (v) document and entity information.

FES

(A)	31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
(A)	31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
(A)	32	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350
	101	The following materials from the Quarterly Report on Form 10-Q of FirstEnergy Solutions Corp. for the period ended September 30, 2014, formatted in XBRL (Extensible Business Reporting Language): (i) Consolidated Statements of Income and Comprehensive Income, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Cash Flows, (iv) related notes to these financial statements and (v) document and entity information.

(A) Provided herein in electronic format as an exhibit.

Pursuant to paragraph (b)(4)(iii)(A) of Item 601 of Regulation S-K, neither FirstEnergy nor FES have filed as an exhibit to this Form 10-Q any instrument with respect to long-term debt if the respective total amount of securities authorized thereunder does not exceed 10% of its respective total assets, but each hereby agrees to furnish to the SEC on request any such documents.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, each Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

November 4, 2014

FIRSTENERGY CORP.
Registrant

FIRSTENERGY SOLUTIONS CORP.
Registrant

/s/ K. Jon Taylor
K. Jon Taylor
Vice President, Controller
and Chief Accounting Officer

EXHIBIT INDEX

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