FIRSTENERGY CORP
Form 10-Q
October 29, 2015

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, 2015

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 SEPTEMBER 30, 2015
FirstEnergy Corp., $0.10 par value	423,041,782
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," "target," "will," "intend," “believe,” "project," “estimate," "plan" and similar words. Forward-looking statements involve estimates, assumptions, known and unknown risks, uncertainties and other factors that may cause actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements, which may include the following:

- The speed and nature of increased competition in the electric utility industry, in general, and the retail sales market in particular.
- The ability to experience growth in the Regulated Distribution and Regulated Transmission segments and to successfully implement our revised sales strategy for the CES segment.
- The accomplishment of our regulatory and operational goals in connection with our transmission investment plan, including but not limited to, our pending transmission rate case, the proposed transmission asset transfer, and the effectiveness of our repositioning strategy to reflect a more regulated business profile.
- Changes in assumptions regarding economic conditions within our territories, assessment of the reliability of our transmission system, or the availability of capital or other resources supporting identified transmission investment opportunities.
- The impact of the regulatory process on the pending matters at the federal level and in the various states in which we do business including, but not limited to, matters related to rates and the ESP IV in Ohio.
- The impact of the federal regulatory process on FERC-regulated entities and transactions, in particular FERC regulation of wholesale energy and capacity markets, including PJM markets and FERC-jurisdictional wholesale transactions; FERC regulation of cost-of-service rates, including FERC Opinion No. 531's revised ROE methodology for FERC-jurisdictional wholesale generation and transmission utility service; and FERC’s compliance and enforcement activity, including compliance and enforcement activity related to NERC’s mandatory reliability standards.
- The uncertainties of various cost recovery and cost allocation issues resulting from ATSI's realignment into PJM.
- Economic or weather conditions affecting future sales and margins such as a polar vortex or other significant weather events, and all associated regulatory events or actions.
- Changing energy, capacity and commodity market prices including, but not limited to, coal, natural gas and oil, and their availability and impact on margins and asset valuations.
- 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, the effects of the EPA's CPP, CCR, CSAPR and MATS programs, including our estimated costs of compliance, CWA waste water effluent limitations for power plants, and CWA 316(b) water intake regulation.
- The uncertainty of the timing and amounts of the capital expenditures that may arise in connection with any litigation, including NSR litigation, or potential regulatory initiatives or rulemakings (including that such initiatives or rulemakings 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 as they relate to the reliability of the transmission grid, the timing thereof.
- The impact of other future changes to the operational status or availability of our generating units and any capacity performance charges associated with unit unavailability.
- Adverse regulatory or legal decisions and outcomes with respect to our nuclear operations (including, but not limited to the revocation or non-renewal of necessary licenses, approvals or operating permits by the NRC or as a result of the incident at Japan's Fukushima Daiichi Nuclear Plant).
- Issues arising from the indications of cracking in the shield building at Davis-Besse.

- The risks and uncertainties associated with litigation, arbitration, mediation and like proceedings, including, but not limited to, any such proceedings related to vendor commitments.
- The impact of labor disruptions by our unionized workforce.
- Replacement power costs being higher than anticipated or not fully hedged.
- The ability to comply with applicable state and federal reliability standards and energy efficiency and peak demand reduction mandates.
- Changes in customers' demand for power, including, but not limited to, changes resulting from the implementation of state and federal energy efficiency and peak demand reduction mandates.
- The ability to accomplish or realize anticipated benefits from strategic and financial goals, including, but not limited to, the ability to continue to reduce costs and to successfully execute our financial plans designed to improve our credit metrics and strengthen our balance sheet through, among other actions, our previously-implemented dividend reduction, our cash flow improvement plan 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 financial plans, the cost of such capital and overall condition of the capital and credit markets affecting us and our subsidiaries.
- Actions that may be taken by credit rating agencies that could negatively affect us and/or our subsidiaries' access to financing, increase the costs thereof, and increase requirements to post additional collateral to support outstanding commodity positions, LOCs and other financial guarantees.
- Changes in national and regional economic conditions affecting us, our subsidiaries and/or our major industrial and commercial customers, and other counterparties with which we do business, including fuel suppliers.
- The impact of any changes in tax laws or regulations or adverse tax audit results or rulings.
- Issues concerning the stability of domestic and foreign financial institutions and counterparties with which we do business.
- The risks associated with cyber-attacks on our electronic data centers that could compromise the information stored on our networks, including proprietary information and customer data.
- The risks and other factors discussed from time to time in our SEC filings, and other similar factors.

Dividends declared from time to time on FE's common stock during any period may in the aggregate vary from prior periods due to circumstances considered by FE's Board of Directors at the time of the actual declarations. A security rating is not a recommendation to buy or hold securities and is subject to revision or withdrawal at any time by the assigning rating agency. Each rating should be evaluated independently of any other rating.

The foregoing review of factors should not be construed as exhaustive. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor assess the impact of any such factor on FirstEnergy's business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. The registrants expressly disclaim any current intention to update, except as required by law, any forward-looking statements contained herein as a result of new information, future events or otherwise.

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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.
AESC	Allegheny Energy Service Corporation, a subsidiary of 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
CES	Competitive Energy Services, a reportable operating segment of FirstEnergy
FE	FirstEnergy Corp., a public utility holding company
FELHC	FirstEnergy License Holding Company, Inc.
FENOC	FirstEnergy Nuclear Operating Company, which operates nuclear generating facilities
FES	FirstEnergy Solutions Corp., which provides energy-related products and services
FESC	FirstEnergy Service Company, which provides legal, financial and other corporate support services
FET	FirstEnergy Transmission, LLC, formerly known as Allegheny Energy Transmission, LLC which is the parent of ATSI, TrAIL and MAIT, 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
MAIT	Mid-Atlantic Interstate Transmission, LLC, a subsidiary of FET, formed to own and operate transmission facilities
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:

AAA	American Arbitration Association
AEP	American Electric Power Company, Inc.
AFS	Available-for-sale
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
AOCI	Accumulated Other Comprehensive Income
Apple®	Apple®, iPad® and iPhone® are registered trademarks of Apple Inc.

GLOSSARY OF TERMS, Continued

ARR	Auction Revenue Right
ASU	Accounting Standards Update
ASLB	Atomic Safety and Licensing Board
BGS	Basic Generation Service
BNSF	BNSF Railway Company
BRA	PJM RPM Base Residual Auction
CAA	Clean Air Act
CCB	Coal Combustion By-Product
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
CONE	Cost-of-New-Entry
CPP	EPA's Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
CSX	CSX Transportation, Inc.
CTA	Consolidated Tax Adjustment
CWA	Clean Water Act
DCR	Delivery Capital Recovery
DOE	United States Department of Energy
DR	Demand Response
DSIC	Distribution System Improvement Charge
DSP	Default Service Plan
EDC	Electric Distribution Company
EE&C	Energy Efficiency and Conservation
EGS	Electric Generation Supplier
ELPC	Environmental Law & Policy Center
EmPOWER Maryland	EmPower Maryland Energy Efficiency Act
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
ICE	IntercontinentalExchange, Inc.
IRS	Internal Revenue Service
ISO	Independent System Operator

kV	Kilovolt
KWH	Kilowatt-hour
LBR	Little Blue Run
LMP	Locational Marginal Price
LOC	Letter of Credit

GLOSSARY OF TERMS, Continued

LSE	Load Serving Entity
LTIIPs	Long-Term Infrastructure Improvement Plans
MATS	Mercury and Air Toxics Standards
MDPSC	Maryland Public Service Commission
MISO	Midcontinent Independent System Operator, Inc.
MLP	Master Limited Partnership
mmBTU	One Million British Thermal Units
Moody’s	Moody’s Investors Service, Inc.
MVP	Multi-Value Project
MW	Megawatt
MWD	Megawatt-day
MWH	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NDT	Nuclear Decommissioning Trust
NERC	North American Electric Reliability Corporation
NGO	Non-Governmental Organization
Ninth Circuit	United States Court of Appeals for the Ninth Circuit
NJBPU	New Jersey Board of Public Utilities
NMB	Non-Market Based
NOV	Notice of Violation
NOx	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NPNS	Normal Purchases and Normal Sales
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
OCA	Office of Consumer Advocate
OCC	Ohio Consumers' Counsel
OEPA	Ohio Environmental Protection Agency
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.
PJM Region	The aggregate of the zones within PJM
PJM Tariff	PJM Open Access Transmission Tariff
PM	Particulate Matter
POLR	Provider of Last Resort
POR	Purchase of Receivables
PPB	Parts Per Billion
PPUC	Pennsylvania Public Utility Commission
PSA	Power Supply Agreement
PSD	Prevention of Significant Deterioration

PUCO	Public Utilities Commission of Ohio
PURPA	Public Utility Regulatory Policies Act of 1978
RCRA	Resource Conservation and Recovery Act
REC	Renewable Energy Credit
REIT	Real Estate Investment Trust

GLOSSARY OF TERMS, Continued

RFC	ReliabilityFirst Corporation
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
ROE	Return on Equity
RPM	Reliability Pricing Model
RSS	Rich Site Summary
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
SEC Regulation FD	SEC Regulation Fair Disclosure
SERTP	Southeastern Regional Transmission Planning
Seventh Circuit	United States Court of Appeals for the Seventh Circuit
SIP	State Implementation Plan(s) Under the Clean Air Act
SO_2	Sulfur Dioxide
SOS	Standard Offer Service
SPE	Special Purpose Entity
SREC	Solar Renewable Energy Credit
SSO	Standard Service Offer
TDS	Total Dissolved Solid
TMI-2	Three Mile Island Unit 2
TTS	Temporary Transaction Surcharge
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
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)	2015	2014	2015	2014
REVENUES:				
Electric utilities	$2,872	$2,554	$8,180	$7,542
Unregulated businesses	1,251	1,334	3,305	4,024
Total revenues*	4,123	3,888	11,485	11,566
OPERATING EXPENSES:				
Fuel	482	544	1,378	1,711
Purchased power	1,209	1,188	3,311	3,726
Other operating expenses	850	858	2,823	3,061
Provision for depreciation	328	308	969	904
Amortization of regulatory assets, net	110	35	201	27
General taxes	236	239	747	738
Total operating expenses	3,215	3,172	9,429	10,167
OPERATING INCOME	908	716	2,056	1,399
OTHER INCOME (EXPENSE):				
Loss on debt redemptions	—	—	—	(8)
Investment income (loss)	(28)	16	(14)	67
Interest expense	(285)	(275)	(846)	(802)
Capitalized financing costs	26	28	93	89
Total other expense	(287)	(231)	(767)	(654)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	621	485	1,289	745
INCOME TAXES	226	152	485	226
INCOME FROM CONTINUING OPERATIONS	395	333	804	519
Discontinued operations (net of income taxes of $69) (Note 14)	—	—	—	86
NET INCOME	$395	$333	$804	$605
EARNINGS PER SHARE OF COMMON STOCK:				
Basic - Continuing Operations	$0.94	$0.79	$1.91	$1.24
Basic - Discontinued Operations (Note 14)	—	—	—	0.20

Basic - Net Earnings per Basic Share	$0.94	$0.79	$1.91	$1.44
Diluted - Continuing Operations	$0.93	$0.79	$1.90	$1.24
Diluted - Discontinued Operations (Note 14)	—	—	—	0.20
Diluted - Net Earnings per Diluted Share	$0.93	$0.79	$1.90	$1.44
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING:				
Basic	423	420	422	419
Diluted	424	421	423	420
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$0.72	$0.72	$1.44	$1.44

* Includes excise tax collections of $109 million and $105 million in the three months ended September 30, 2015 and 2014, respectively, and $320 million and $321 million in the nine months ended September 30, 2015 and 2014, respectively.

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2015	2014	2015	2014
NET INCOME	$395	$333	$804	$605
OTHER COMPREHENSIVE INCOME (LOSS):				
Pension and OPEB prior service costs	(31)	(42)	(94)	(126)
Amortized losses (gains) on derivative hedges	2	—	4	(1)
Change in unrealized gains on available-for-sale securities	(11)	(11)	(21)	40
Other comprehensive loss	(40)	(53)	(111)	(87)
Income tax benefits on other comprehensive loss	(15)	(21)	(42)	(35)
Other comprehensive loss, net of tax	(25)	(32)	(69)	(52)
COMPREHENSIVE INCOME	$370	$301	$735	$553

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, 2015	December 31, 2014
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$86	$85
Receivables-		
Customers, net of allowance for uncollectible accounts of $64 in 2015 and $59 in 2014	1,592	1,554
Other, net of allowance for uncollectible accounts of $5 in 2015 and 2014	180	225
Materials and supplies	738	817
Prepaid taxes	148	128
Derivatives	156	159
Accumulated deferred income taxes	639	518
Collateral	123	230
Other	171	160
	3,833	3,876
PROPERTY, PLANT AND EQUIPMENT:		
In service	49,200	47,484
Less — Accumulated provision for depreciation	14,917	14,150
	34,283	33,334
Construction work in progress	2,327	2,449
	36,610	35,783
INVESTMENTS:		
Nuclear plant decommissioning trusts	2,279	2,341
Other	875	881
	3,154	3,222
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	6,418	6,418
Regulatory assets	1,430	1,411
Other	1,218	1,456
	9,066	9,285
	$52,663	$52,166
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$1,148	$804
Short-term borrowings	1,933	1,799
Accounts payable	994	1,279
Accrued taxes	508	490
Accrued compensation and benefits	345	329
Derivatives	124	167
Other	824	693
	5,876	5,561
CAPITALIZATION:		
Common stockholders' equity-		
	42	42

Common stock, $0.10 par value, authorized 490,000,000 shares - 423,041,782 and 421,102,570 shares outstanding as of September 30, 2015 and December 31, 2014, respectively		
Other paid-in capital	9,926	9,847
Accumulated other comprehensive income	177	246
Retained earnings	2,482	2,285
Total common stockholders' equity	12,627	12,420
Noncontrolling interest	1	2
Total equity	12,628	12,422
Long-term debt and other long-term obligations	19,093	19,176
	31,721	31,598
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	7,581	7,057
Retirement benefits	3,861	3,932
Asset retirement obligations	1,429	1,387
Deferred gain on sale and leaseback transaction	799	824
Adverse power contract liability	205	217
Other	1,191	1,590
	15,066	15,007
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 11)		
	$52,663	$52,166

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Nine Months Ended September 30, 2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$804	$605
Adjustments to reconcile net income to net cash from operating activities-		
Income from discontinued operations (Note 14)	—	(86)
Provision for depreciation	969	904
Amortization of regulatory assets, net	201	27
Nuclear fuel amortization	166	160
Amortization of debt related costs	31	40
Deferred purchased power and other costs	(73)	(89)
Deferred income taxes and investment tax credits, net	428	327
Investment impairments	70	10
Deferred costs on sale leaseback transaction, net	37	37
Amortization of customer intangibles and deferred advertising costs	16	50
Retirement benefits	(18)	(60)
Pension trust contributions	(143)	—
Commodity derivative transactions, net (Note 9)	(64)	60
Loss on debt redemptions	—	8
Lease payments on sale and leaseback transaction	(102)	(100)
Impairment of long lived assets	31	—
Changes in current assets and liabilities-		
Receivables	7	90
Materials and supplies	32	(19)
Prepayments and other current assets	(43)	42
Accounts payable	(285)	(47)
Accrued taxes	(68)	(145)
Accrued interest	37	66
Accrued compensation and benefits	16	(74)
Other current liabilities	26	3
Cash collateral, net	59	(71)
Other	183	(1)
Net cash provided from operating activities	2,317	1,737
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Long-term debt	1,084	3,778
Short-term borrowings, net	134	—
Redemptions and Repayments-		
Long-term debt	(781)	(1,062)
Short-term borrowings, net	—	(1,783)
Common stock dividend payments	(455)	(452)
Other	(11)	(37)
Net cash (used for) provided from financing activities	(29)	444

CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(2,025)	(2,473)
Nuclear fuel	(101)	(98)
Proceeds from asset sales	20	394
Sales of investment securities held in trusts	1,126	1,511
Purchases of investment securities held in trusts	(1,213)	(1,593)
Cash investments	19	42
Asset removal costs	(111)	(80)
Other	(2)	7
Net cash used for investing activities	(2,287)	(2,290)
Net change in cash and cash equivalents	1	(109)
Cash and cash equivalents at beginning of period	85	218
Cash and cash equivalents at end of period	$86	$109

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

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

(In millions)	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
REVENUES:				
Electric sales to non-affiliates	$1,157	$1,315	$3,146	$3,989
Electric sales to affiliates	135	164	547	689
Other	46	42	141	124
Total revenues	1,338	1,521	3,834	4,802
OPERATING EXPENSES:				
Fuel	245	270	666	923
Purchased power from affiliates	103	64	250	203
Purchased power from non-affiliates	401	627	1,336	2,274
Other operating expenses	246	356	1,012	1,276
Provision for depreciation	79	83	240	236
General taxes	24	31	78	99
Total operating expenses	1,098	1,431	3,582	5,011
OPERATING INCOME (LOSS)	240	90	252	(209)
OTHER INCOME (EXPENSE):				
Loss on debt redemptions	—	(1)	—	(6)
Investment income (loss)	(21)	13	(7)	57
Miscellaneous income	1	1	5	5
Interest expense — affiliates	(2)	(1)	(6)	(5)
Interest expense — other	(36)	(37)	(110)	(110)
Capitalized interest	8	7	26	27
Total other expense	(50)	(18)	(92)	(32)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES (BENEFITS)	190	72	160	(241)
INCOME TAXES (BENEFITS)	70	28	64	(95)
INCOME (LOSS) FROM CONTINUING OPERATIONS	120	44	96	(146)
Discontinued operations (net of income taxes of $70) (Note 14)	—	—	—	116
NET INCOME (LOSS)	$120	$44	$96	$(30)
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)				
NET INCOME (LOSS)	$120	$44	$96	$(30)

OTHER COMPREHENSIVE INCOME (LOSS):				
Pension and OPEB prior service costs	(4)	(4)	(12)	(14)
Amortized gains on derivative hedges	—	(2)	(2)	(7)
Change in unrealized gain on available-for-sale securities	(11)	(9)	(20)	35
Other comprehensive income (loss)	(15)	(15)	(34)	14
Income taxes (benefits) on other comprehensive income (loss)	(6)	(6)	(13)	5
Other comprehensive income (loss), net of tax	(9)	(9)	(21)	9
COMPREHENSIVE INCOME (LOSS)	$111	$35	$75	$(21)

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, 2015	December 31, 2014
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$2	$2
Receivables-		
Customers, net of allowance for uncollectible accounts of $14 in 2015 and $18 in 2014	303	415
Affiliated companies	510	525
Other, net of allowance for uncollectible accounts of $3 in 2015 and 2014	78	107
Materials and supplies	446	492
Derivatives	147	147
Collateral	122	229
Prepayments and other	138	95
	1,746	2,012
PROPERTY, PLANT AND EQUIPMENT:		
In service	14,003	13,596
Less — Accumulated provision for depreciation	5,519	5,208
	8,484	8,388
Construction work in progress	925	1,010
	9,409	9,398
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,323	1,365
Other	10	10
	1,333	1,375
DEFERRED CHARGES AND OTHER ASSETS:		
Customer intangibles	65	78
Goodwill	23	23
Property taxes	10	41
Unamortized sale and leaseback costs	260	217
Derivatives	118	52
Other	123	114
	599	525
	$13,087	$13,310
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$537	$506
Short-term borrowings-		
Affiliated companies	17	35
Other	8	99
Accounts payable-		
Affiliated companies	297	416
Other	131	248
Accrued taxes	84	102
Derivatives	121	166

Other	161	184
	1,356	1,756
CAPITALIZATION:		
Common stockholder's equity-		
Common stock, without par value, authorized 750 shares - 7 shares outstanding as of September 30, 2015 and December 31, 2014	3,609	3,594
Accumulated other comprehensive income	36	57
Retained earnings	2,030	1,934
Total common stockholder's equity	5,675	5,585
Long-term debt and other long-term obligations	2,530	2,608
	8,205	8,193
NONCURRENT LIABILITIES:		
Deferred gain on sale and leaseback transaction	799	824
Accumulated deferred income taxes	672	511
Retirement benefits	334	324
Asset retirement obligations	861	841
Derivatives	60	14
Other	800	847
	3,526	3,361
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 11)		
	$13,087	$13,310

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)

(In millions)	Nine Months Ended September 30, 2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$96	$(30)
Adjustments to reconcile net income (loss) to net cash from operating activities-		
Income from discontinued operations (Note 14)	—	(116)
Provision for depreciation	240	236
Nuclear fuel amortization	166	160
Deferred costs on sale and leaseback transaction, net	37	37
Amortization of customer intangibles and deferred advertising costs	16	50
Deferred income taxes and investment tax credits, net	139	(15)
Investment impairments	63	9
Commodity derivative transactions, net (Note 9)	(65)	61
Lease payments on sale and leaseback transaction	(102)	(100)
Loss on debt redemptions	—	6
Impairment of long lived assets	18	—
Changes in current assets and liabilities-		
Receivables	171	609
Materials and supplies	(1)	(23)
Prepayments and other current assets	—	26
Accounts payable	(241)	(383)
Accrued taxes	(28)	7
Accrued compensation and benefits	2	(15)
Other current liabilities	24	(3)
Cash collateral, net	107	(82)
Other	(6)	(6)
Net cash provided from operating activities	636	428
CASH FLOWS FROM FINANCING ACTIVITIES:		
New financing-		
Long-term debt	339	878
Equity contribution from parent	—	500
Redemptions and repayments-		
Long-term debt	(382)	(749)
Short-term borrowings, net	(109)	(414)
Other	(5)	(14)
Net cash (used for) provided from financing activities	(157)	201
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(341)	(586)
Nuclear fuel	(101)	(98)
Proceeds from asset sales	13	307
Sales of investment securities held in trusts	503	890

Purchases of investment securities held in trusts	(546)	(933)
Cash investments	(10)	—
Loans to affiliated companies, net	—	(214)
Other	3	5
Net cash used for investing activities	(479)	(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

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

FIRSTENERGY CORP. AND SUBSIDIARIES

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(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. FE's principal business is the holding, directly or indirectly, of all of the outstanding common stock of its principal subsidiaries: OE, CEI, TE, Penn (a wholly owned subsidiary of OE), JCP&L, ME, PN, FESC, FES and its principal subsidiaries (FG and NG), AE Supply, MP, PE, WP, FET and its principal subsidiaries (ATSI and TrAIL), and AESC. In addition, FE holds all of the outstanding common stock of other direct subsidiaries including: FirstEnergy Properties, Inc., FEV, FENOC, FELHC, Inc., GPU Nuclear, Inc., and AE Ventures, Inc.

FirstEnergy and its subsidiaries are principally involved in the generation, transmission, and distribution of electricity. FirstEnergy's ten utility operating companies comprise one of the nation's largest investor-owned electric systems, based on serving six million customers in the Midwest and Mid-Atlantic regions. Its generation subsidiaries control nearly 17,000 MW of capacity from a diverse mix of non-emitting nuclear, scrubbed coal, natural gas, hydroelectric and other renewables. FirstEnergy's transmission operations include approximately 24,000 miles of lines and three regional transmission operation centers.
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, 2014.

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 necessarily 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 as appropriate. 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, 2015 and 2014, capitalized financing costs on FirstEnergy's Consolidated Statements of Income include $10 million and $14 million, respectively of allowance for equity funds used during construction and $16 million and $14 million, respectively, of capitalized interest. For the nine months ended

September 30, 2015 and 2014, capitalized financing costs on FirstEnergy's Consolidated Statements of Income include $40 million and $35 million, respectively, of allowance for equity funds used during construction, and $53 million and $54 million, respectively, of capitalized interest.

During the first nine months of 2015, FirstEnergy recognized an impairment of $31 million associated with certain non-core assets, including equipment and facilities. The charges are classified as a component of Other operating expenses in the Consolidated Statement of Income.

New Accounting Pronouncements

In May 2014, the FASB issued "Revenue from Contracts with Customers", requiring entities to recognize revenue by applying a five-step model in accordance with the core principle to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In addition, the accounting for costs to obtain or fulfill a contract with a customer is specified and disclosure requirements for revenue recognition are expanded. In August 2015, the FASB issued a final Accounting Standards Update deferring the effective date until fiscal years beginning after December 15, 2017. Earlier application is permitted only as of annual reporting periods beginning after December 15, 2016, (the original effective date). The standard 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.

In February 2015, the FASB issued, "Consolidations: Amendments to the Consolidation Analysis", which amends current consolidation guidance including changes to both the variable and voting interest models used by companies to evaluate whether an entity should be consolidated. This standard is effective for interim and annual periods beginning after December 15, 2015, and early adoption is permitted. A reporting entity must apply the amendments using a modified retrospective approach by recording a cumulative-effect adjustment to equity as of the beginning of the period of adoption or apply the amendments retrospectively. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

In April 2015, the FASB issued, "Simplifying the Presentation of Debt Issuance Costs", which requires debt issuance costs to be presented on the balance sheet as a direct deduction from the carrying value of the associated debt liability, consistent with the presentation of a debt discount. The guidance is effective for financial statements issued for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years. Upon adoption, an entity must apply the new guidance retrospectively to all prior periods presented in the financial statements. FirstEnergy does not expect this amendment to have a material effect on its financial statements.

In August 2015, the FASB issued ASU 2015-13, "Application of the NPNS Scope Exception to Certain Electricity Contracts within Nodal Energy Markets", which confirmed that forward physical contracts for the sale or purchase of electricity meet the physical delivery criterion within the NPNS scope exception when the electricity is transmitted through a grid managed by an ISO. As a result, an entity can elect the NPNS exception within the derivative accounting guidance for such contracts, provided that the other NPNS criteria are also met. The ASU was effective on issuance and requires prospective application. FirstEnergy does not expect this to have a material effect on its financial statements.

2. GOODWILL

In a business combination, the excess of the purchase price over the estimated fair value of the assets acquired and liabilities assumed is recognized as goodwill. FirstEnergy's reporting units are consistent with its reportable segments and consist of Regulated Distribution, Regulated Transmission, and CES. The following table presents goodwill by reporting unit (there have been no changes in goodwill for any reporting unit during 2015):

Goodwill	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Consolidated
	(In millions)			
Balance as of September 30, 2015	$5,092	$526	$800	$6,418

FirstEnergy evaluates goodwill for impairment annually on July 31 and more frequently if indicators of impairment arise. For 2015, FirstEnergy performed a qualitative assessment of the Regulated Distribution and Regulated Transmission reporting units, assessing economic, industry and market considerations in addition to the reporting unit's overall financial performance. It was determined that the fair value of these reporting units were, more likely than not, greater than their carrying value and a quantitative analysis was not necessary for 2015.

FirstEnergy performed a quantitative assessment of the CES reporting unit as of July 31, 2015. Key assumptions incorporated into the CES discounted cash flow analysis requiring significant management judgment included the following:

- Future Energy and Capacity Prices: FirstEnergy used observable market information for near term forward power prices, PJM auction results for near term capacity pricing, and a longer-term pricing model for energy and capacity that considered the impact of key factors such as load growth, plant retirements, carbon and other environmental regulations, and natural gas pipeline construction, as well as coal and natural gas pricing.
- Retail Sales and Margin: FirstEnergy used CES' current retail targeted portfolio to estimate future retail sales volume as well as historical financial results to estimate retail margins.
-

Operating and Capital Costs: FirstEnergy used estimated future operating and capital costs, including the estimated impact on costs of pending carbon and other environmental regulations, as well as costs associated with capacity performance reforms in the PJM market.

- Discount Rate: A discount rate of 8.25%, based on a capital structure, return on debt and return on equity of selected comparable companies.
- Terminal Value: A terminal value of 7.0x earnings before interest, taxes, depreciation and amortization based on consideration of peer group data and analyst consensus expectations.

Based on the results of the quantitative analysis, the fair value of the CES reporting unit exceeded its carrying value by approximately 10%. Continued weak economic conditions, lower than expected power and capacity prices, a higher cost of capital, and revised environmental requirements could have a negative impact on future goodwill assessments.

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	2015	2014	2015	2014
Income from continuing operations	$395	$333	$804	$519
Discontinued operations (Note 14)	—	—	—	86
Net income	$395	$333	$804	$605
Weighted average number of basic shares outstanding	423	420	422	419
Assumed exercise of dilutive stock options and awards(1)	1	1	1	1
Weighted average number of diluted shares outstanding	424	421	423	420
Earnings per share:				
Basic earnings per share:				
Income from continuing operations	$0.94	$0.79	$1.91	$1.24
Discontinued operations (Note 14)	—	—	—	0.20
Net earnings per basic share	$0.94	$0.79	$1.91	$1.44
Diluted earnings per share:				
Income from continuing operations	$0.93	$0.79	$1.90	$1.24
Discontinued operations (Note 14)	—	—	—	0.20
Net earnings per diluted share	$0.93	$0.79	$1.90	$1.44

(1) For both the three months ended September 30, 2015 and September 30, 2014, one million shares were excluded from the calculation of diluted shares outstanding, as their inclusion would be antidilutive. For the nine months ended September 30, 2015 and September 30, 2014, one million and two million shares, respectively, were excluded from the calculation of diluted shares outstanding, as their inclusion would be antidilutive.

4. PENSION AND OTHER POSTEMPLOYMENT BENEFITS

In March 2015, FirstEnergy contributed $143 million to its qualified pension plan. The components of the consolidated net periodic cost (credits) for pension and OPEB (including amounts capitalized) were as follows:

Components of Net Periodic Benefit Costs (Credits)	Pension		OPEB	
For the Three Months Ended September 30,	2015	2014	2015	2014
	(In millions)			
Service costs	$49	$42	$2	$2
Interest costs	96	100	7	9
Expected return on plan assets	(111)	(116)	(9)	(8)
Amortization of prior service costs (credits)	2	2	(33)	(44)
Net periodic costs (credits)	$36	$28	$(33)	$(41)

Components of Net Periodic Benefit Costs (Credits)	Pension		OPEB	
For the Nine Months Ended September 30,	2015	2014	2015	2014
	(In millions)			
Service costs	$145	$125	$4	$6
Interest costs	288	301	21	29
Expected return on plan assets	(333)	(346)	(25)	(24)
Amortization of prior service costs (credits)	6	6	(100)	(132)
Net periodic costs (credits)	$106	$86	$(100)	$(121)

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

	Pension		OPEB	
	2015	2014	2015	2014
	(In millions)			
For the Three Months Ended September 30,	$4	$5	$(5)	$(5)
For the Nine Months Ended September 30,	12	13	(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)	Pension		OPEB	
For the Three Months Ended September 30,	2015	2014	2015	2014
	(In millions)			
FirstEnergy	$25	$19	$(21)	$(24)
FES	4	4	(4)	(4)

Net Periodic Benefit Expense (Credit)	Pension		OPEB	
For the Nine Months Ended September 30,	2015	2014	2015	2014
	(In millions)			
FirstEnergy	$74	$61	$(66)	$(78)
FES	12	12	(12)	(13)

5. ACCUMULATED OTHER COMPREHENSIVE INCOME

The changes in AOCI, net of tax, in the three and nine months ended September 30, 2015 and 2014, for FirstEnergy are included in the following tables:
FirstEnergy

	Gains & Losses on Cash Flow Hedges (In millions)	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
AOCI Balance as of July 1, 2015	$(36)	$19	$219	$202
Other comprehensive loss before reclassifications	—	(8)	—	(8)
Amounts reclassified from AOCI	2	(3)	(31)	(32)
Other comprehensive income (loss)	2	(11)	(31)	(40)
Income tax (benefits) on other comprehensive income (loss)	1	(4)	(12)	(15)
Net other comprehensive income (loss)	1	(7)	(19)	(25)
AOCI Balance as of September 30, 2015	$(35)	$12	$200	$177
AOCI Balance as of July 1, 2014	$(36)	$41	$259	$264
Other comprehensive income before reclassifications	—	2	—	2
Amounts reclassified from AOCI	—	(13)	(42)	(55)
Other comprehensive loss	—	(11)	(42)	(53)
Income tax benefits on other comprehensive loss	—	(5)	(16)	(21)
Net other comprehensive loss	—	(6)	(26)	(32)
AOCI Balance as of September 30, 2014	$(36)	$35	$233	$232

	Gains & Losses on Cash Flow Hedges (In millions)	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
AOCI Balance as of January 1, 2015	$(37)	$25	$258	$246
Other comprehensive loss before reclassifications	—	(1)	—	(1)
Amounts reclassified from AOCI	4	(20)	(94)	(110)
Other comprehensive income (loss)	4	(21)	(94)	(111)
Income tax (benefits) on other comprehensive income (loss)	2	(8)	(36)	(42)
Net other comprehensive income (loss)	2	(13)	(58)	(69)
AOCI Balance as of September 30, 2015	$(35)	$12	$200	$177
AOCI Balance as of January 1, 2014	$(36)	$9	$311	$284

Other comprehensive income before reclassifications	—	86	—	86
Amounts reclassified from AOCI	(1)	(46)	(126)	(173)
Other comprehensive income (loss)	(1)	40	(126)	(87)
Income tax (benefits) on other comprehensive income (loss)	(1)	14	(48)	(35)
Net other comprehensive income (loss)	—	26	(78)	(52)
AOCI Balance as of September 30, 2014	$(36)	$35	$233	$232

The following amounts were reclassified from AOCI for FirstEnergy in the three and nine months ended September 30, 2015 and 2014:

Reclassifications from AOCI [2]	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	Affected Line Item in Consolidated Statements of Income
	(In millions)				
Gains & losses on cash flow hedges					
Commodity contracts	$—	$(2)	$(2)	$(7)	Other operating expenses
Long-term debt	2	2	6	6	Interest expense
	2	—	4	(1)	Total before taxes
	(1)	—	(2)	—	Income taxes
	$1	$—	$2	$(1)	Net of tax
Unrealized gains on AFS securities					
Realized gains on sales of securities	$(3)	$(13)	$(20)	$(46)	Investment income (loss)
	1	5	7	17	Income taxes
	$(2)	$(8)	$(13)	$(29)	Net of tax
Defined benefit pension and OPEB plans					
Prior-service costs	$(31)	$(42)	$(94)	$(126)	[1]
	12	16	36	48	Income taxes
	$(19)	$(26)	$(58)	$(78)	Net of tax

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

The changes in AOCI, net of tax, in the three and nine months ended September 30, 2015 and 2014, for FES are included in the following tables:
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, 2015	$(9)	$16	$38	$45
Other comprehensive loss before reclassifications	—	(7)	—	(7)
Amounts reclassified from AOCI	—	(4)	(4)	(8)
Other comprehensive loss	—	(11)	(4)	(15)
Income tax benefits on other comprehensive loss	—	(5)	(1)	(6)
Net other comprehensive loss	—	(6)	(3)	(9)
AOCI Balance as of September 30, 2015	$(9)	$10	$35	$36
AOCI Balance as of July 1, 2014	$(5)	$36	$41	$72
Other comprehensive income before reclassifications	—	2	—	2
Amounts reclassified from AOCI	(2)	(11)	(4)	(17)
Other comprehensive loss	(2)	(9)	(4)	(15)
Income tax benefits on other comprehensive loss	(1)	(4)	(1)	(6)
Net other comprehensive loss	(1)	(5)	(3)	(9)
AOCI Balance as of September 30, 2014	$(6)	$31	$38	$63

	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, 2015	$(7)	$21	$43	$57
Other comprehensive loss before reclassifications	—	(1)	—	(1)
Amounts reclassified from AOCI	(2)	(19)	(12)	(33)
Other comprehensive loss	(2)	(20)	(12)	(34)
Income tax benefits on other comprehensive loss	—	(9)	(4)	(13)
Net other comprehensive loss	(2)	(11)	(8)	(21)
AOCI Balance as of September 30, 2015	$(9)	$10	$35	$36
AOCI Balance as of January 1, 2014	$(1)	$8	$47	$54
Other comprehensive income before reclassifications	—	78	—	78
Amounts reclassified from AOCI	(7)	(43)	(14)	(64)
Other comprehensive income (loss)	(7)	35	(14)	14
	(2)	12	(5)	5

Income tax (benefits) on other comprehensive income (loss)				
Net other comprehensive income (loss)	(5)	23	(9)	9
AOCI Balance as of September 30, 2014	$(6)	$31	$38	$63

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The following amounts were reclassified from AOCI for FES in the three and nine months ended September 30, 2015 and 2014:

Reclassifications from AOCI [2]	Three Months Ended September 30, 2015	2014	Nine Months Ended September 30, 2015	2014	Affected Line Item in Consolidated Statements of Operations
	(In millions)				
Gains & losses on cash flow hedges					
Commodity contracts	$—	$(2)	$(2)	$(7)	Other operating expenses
	—	1	—	3	Income taxes (benefits)
	$—	$(1)	$(2)	$(4)	Net of tax
Unrealized gains on AFS securities					
Realized gains on sales of securities	$(3)	$(11)	$(18)	$(43)	Investment income (loss)
	1	5	7	16	Income taxes (benefits)
	$(2)	$(6)	$(11)	$(27)	Net of tax
Defined benefit pension and OPEB plans					
Prior-service costs	$(4)	$(4)	$(12)	$(14)	[1]
	1	1	4	5	Income taxes (benefits)
	$(3)	$(3)	$(8)	$(9)	Net of tax

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

6. INCOME TAXES

FirstEnergy’s and FES’ interim effective tax rates reflect the estimated annual effective tax rates for 2015 and 2014. These tax rates are affected by estimated annual permanent items, such as AFUDC equity and other flow-through items, as well as 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, 2015 and 2014 was 36.4% and 31.3%, respectively. The increase in the effective tax rate is primarily due to tax benefits recorded in the third quarter of 2014 associated with an IRS-approved change in accounting method for costs associated with the refurbishment of meters and transformers.

FirstEnergy's effective tax rate from continuing operations for the nine months ended September 30, 2015 and 2014 was 37.6% and 30.3%, respectively. The increase in the effective tax rate for the nine month period ending September 30, 2015 is primarily due to the changes in accounting method as described above and a reduction in state deferred tax liabilities recorded in 2014 resulting from changes in state apportionment factors, as well as the elimination of certain future tax liabilities associated with basis differences recognized in the first nine months of 2014.

FES’ effective tax rate from continuing operations for the three months ended September 30, 2015 and 2014 was 36.8% and 38.9%, respectively. The decrease in the effective tax rate primarily relates to a valuation allowance against local municipality NOL carryforwards recognized in the third quarter of 2014.

FES' effective tax rate from continuing operations for the nine months ended September 30, 2015 and 2014 was 40.0% and 39.4%, respectively.

As of September 30, 2015, it is reasonably possible that approximately $10 million of unrecognized tax benefits may be resolved within the next twelve months as a result of the statute of limitations expiring, all of which would affect FirstEnergy's effective tax rate.

In January 2015, the IRS completed its examination of the 2013 federal income tax return and issued a Revenue Agent Report. For tax year 2013 there was no material impact to FirstEnergy's effective tax rate associated with this examination. Tax years 2014 and 2015 are currently under review by the IRS.

7. VARIABLE INTEREST ENTITIES

FirstEnergy performs qualitative analyses based on control and economics to determine whether a variable interest classifies FirstEnergy as the primary beneficiary (a controlling financial interest) of a VIE. An enterprise has a controlling financial interest if it has both power and economic control, such that an entity has (i) the power to direct the activities of a VIE that most significantly impact the entity’s economic performance, and (ii) 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.

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.

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

Consolidated VIEs

VIEs in which FirstEnergy is the primary beneficiary consist of the following (included in FirstEnergy's consolidated financial statements):

- PNBV Trust - 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.
- Ohio Securitization - In September 2012, the Ohio Companies created separate, wholly-owned limited liability companies (SPEs) which issued phase-in recovery bonds to securitize the recovery of certain all-electric customer heating discounts, fuel and purchased power regulatory assets. The phase-in recovery bonds are payable only from, and secured by, phase-in recovery property owned by the SPEs. The bondholder has no recourse to the general credit of FirstEnergy or any of the Ohio Companies. Each of the Ohio Companies, as servicer of its respective SPE, manages and administers the phase-in recovery property including the billing, collection and remittance of usage-based charges payable by retail electric customers. In the aggregate, the Ohio Companies are entitled to annual servicing fees of $445,000 that are recoverable through the usage-based charges. The SPEs are considered VIEs and each one is consolidated into its applicable utility. As of September 30, 2015 and December 31, 2014, $362 million and $386 million of the phase-in recovery bonds were outstanding, respectively.

- JCP&L Securitization - In June 2002, JCP&L Transition Funding sold transition bonds to securitize the recovery of JCP&L's bondable stranded costs associated with the previously divested Oyster Creek Nuclear Generating Station. In August 2006, JCP&L Transition Funding II sold transition bonds to securitize the recovery of deferred costs associated with JCP&L's supply of BGS. JCP&L did not purchase and does not own any of the transition bonds, which are included as long-term debt on FirstEnergy's and JCP&L's Consolidated Balance Sheets. The transition bonds are the sole obligations of JCP&L Transition Funding and JCP&L Transition Funding II and are collateralized by each company's equity and assets, which consist primarily of bondable transition property. As of September 30, 2015 and December 31, 2014, $139 million and $168 million of the transition bonds were outstanding, respectively.
- MP and PE Environmental Funding Companies - The entities issued bonds of which the proceeds were used to construct environmental control facilities. The special purpose limited liability companies own the irrevocable right to collect non-bypassable environmental control charges from all customers who receive electric delivery service in MP's and PE's West Virginia service territories. Principal and interest owed on the environmental control bonds is secured by, and payable solely from, the proceeds of the environmental control charges. The right to collect environmental control charges is not included as an asset on FirstEnergy's consolidated balance sheets. Creditors of FirstEnergy, other than the special purpose limited liability companies, have no recourse to any assets or revenues of the special purpose limited liability companies. As of September 30, 2015 and December 31, 2014, $429 million and $450 million of the environmental control bonds were outstanding, respectively.

Unconsolidated VIEs

FirstEnergy is not the primary beneficiary of the following VIEs:

- Signal Peak - 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 with coal sales in U.S. and international markets. 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. FEV's equity method investment in Global Holding was $364 million as of September 30, 2015.

A subsidiary of Global Holding had the right to put up to 2 million tons annually from the Signal Peak underground mine to FG through 2024. During the first quarter of 2015, the Global Holding subsidiary eliminated its right under the put in exchange for FirstEnergy extending its guarantee under Global Holding's $300 million senior secured term loan facility through 2020, resulting in a pre-tax charge of $24 million in the first quarter of 2015. (See Note 11, Commitments, Guarantees and Contingencies.)

- PATH WV - PATH is a 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. FirstEnergy's ownership interest in PATH-WV is subject to the equity method of accounting.
- 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 15 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 one of these NUG entities, it does not have a variable interest in the entities or the entities do not meet the criteria to be considered a VIE. FirstEnergy may hold a variable interest in the remaining one entity; 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 during the three months ended September 30, 2015 and 2014 were $29 million and $49 million, respectively, and $86 million and $150 million during the nine months ended September 30, 2015 and 2014, respectively.

- Sale and Leaseback Transactions - 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. 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. As of September 30, 2015, FirstEnergy's leasehold interest was 3.75% of Perry Unit 1, 93.83% of Bruce Mansfield Unit 1 and 2.60% of Beaver Valley Unit 2.

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

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, 2015:

	Maximum Exposure	Discounted Lease Payments, net	Net Exposure
	(In millions)		
FirstEnergy	$1,237	$974	$263
FES	1,162	945	217

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 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 PJM 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 PJM 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.

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, 2015, from those used as of

December 31, 2014. 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, 2015. 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, 2015				December 31, 2014			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$1,271	$—	$1,271	$—	$1,221	$—	$1,221
Derivative assets - commodity contracts	1	255	—	256	1	171	—	172
Derivative assets - FTRs	—	—	17	17	—	—	39	39
Derivative assets - NUG contracts[1]	—	—	1	1	—	—	2	2
Equity securities[2]	651	—	—	651	592	—	—	592
Foreign government debt securities	—	74	—	74	—	76	—	76
U.S. government debt securities	—	176	—	176	—	182	—	182
U.S. state debt securities	—	241	—	241	—	237	—	237
Other[3]	59	124	—	183	55	256	—	311
Total assets	$711	$2,141	$18	$2,870	$648	$2,143	$41	$2,832
Liabilities								
Derivative liabilities - commodity contracts	$(7)	$(163)	$—	$(170)	$(26)	$(141)	$—	$(167)
Derivative liabilities - FTRs	—	—	(14)	(14)	—	—	(14)	(14)
Derivative liabilities - NUG contracts[1]	—	—	(144)	(144)	—	—	(153)	(153)
Total liabilities	$(7)	$(163)	$(158)	$(328)	$(26)	$(141)	$(167)	$(334)
Net assets (liabilities)[4]	$704	$1,978	$(140)	$2,542	$622	$2,002	$(126)	$2,498

(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 $(4) million and $40 million as of September 30, 2015 and December 31, 2014, 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 and FTRs that are classified as Level 3 in the fair value hierarchy for the periods ended September 30, 2015 and December 31, 2014:

	NUG Contracts[1]			FTRs		
	Derivative Assets	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net
	(In millions)					
January 1, 2014 Balance	$20	$(222)	$(202)	$4	$(12)	$(8)
Unrealized gain (loss)	2	(2)	—	47	(1)	46
Purchases	—	—	—	26	(16)	10
Settlements	(20)	71	51	(38)	15	(23)
December 31, 2014 Balance	$2	$(153)	$(151)	$39	$(14)	$25
Unrealized gain (loss)	1	(37)	(36)	3	(1)	2
Purchases	—	—	—	22	(12)	10
Settlements	(2)	46	44	(47)	13	(34)
September 30, 2015 Balance	$1	$(144)	$(143)	$17	$(14)	$3

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

Level 3 Quantitative Information

The following table provides quantitative information for FTRs and NUG contracts that are classified as Level 3 in the fair value hierarchy for the period ended September 30, 2015:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$3	Model	RTO auction clearing prices	($3.50) to $12.20	$1.20	Dollars/MWH
NUG Contracts	$(143)	Model	Generation	500 to 4,094,000	774,000	MWH
			Regional electricity prices	$40.60 to $50.70	$43.40	Dollars/MWH

FES

Recurring Fair Value Measurements	September 30, 2015				December 31, 2014			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$692	$—	$692	$—	$655	$—	$655
Derivative assets - commodity contracts	1	255	—	256	1	171	—	172
Derivative assets - FTRs	—	—	9	9	—	—	27	27
Equity securities[(1)]	457	—	—	457	360	—	—	360
Foreign government debt securities	—	60	—	60	—	57	—	57
U.S. government debt securities	—	24	—	24	—	46	—	46
U.S. state debt securities	—	4	—	4	—	4	—	4
Other[(2)]	—	91	—	91	—	199	—	199
Total assets	$458	$1,126	$9	$1,593	$361	$1,132	$27	$1,520
Liabilities								
Derivative liabilities - commodity contracts	$(7)	$(163)	$—	$(170)	$(26)	$(141)	$—	$(167)
Derivative liabilities - FTRs	—	—	(11)	(11)	—	—	(13)	(13)
Total liabilities	$(7)	$(163)	$(11)	$(181)	$(26)	$(141)	$(13)	$(180)
Net assets (liabilities)[(3)]	$451	$963	$(2)	$1,412	$335	$991	$14	$1,340

(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 $(5) million and $44 million as of September 30, 2015 and December 31, 2014, 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, 2015 and December 31, 2014:

	Derivative Asset	Derivative Liability	Net Asset (Liability)
	(In millions)		
January 1, 2014 Balance	$3	$(11)	$(8)
Unrealized gain (loss)	34	(1)	33
Purchases	15	(16)	(1)
Settlements	(25)	15	(10)
December 31, 2014 Balance	$27	$(13)	$14
Unrealized gain	5	—	5
Purchases	9	(10)	(1)
Settlements	(32)	12	(20)
September 30, 2015 Balance	$9	$(11)	$(2)

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, 2015:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$(2)	Model	RTO auction clearing prices	($3.50) to $12.20	$0.90	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 receivables.

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, 2015 and December 31, 2014:

	September 30, 2015[1]			December 31, 2014[2]		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
	(In millions)					
Debt securities						
FirstEnergy	$1,789	$20	$1,809	$1,724	$27	$1,751
FES	814	10	824	788	13	801
Equity securities						
FirstEnergy	$640	$11	$651	$533	$58	$591
FES	449	8	457	329	31	360

(1) Excludes short-term cash investments: FE Consolidated - $61 million; FES - $42 million.
(2) Excludes short-term cash investments: FE Consolidated - $241 million; FES - $204 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 and nine months ended September 30, 2015 and 2014 were as follows:

Three Months Ended September 30, 2015	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	$307	$33	$(32)	$(46)	$25
FES	127	28	(24)	(41)	14

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

Nine Months Ended September 30, 2015	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	$1,126	$135	$(121)	$(70)	$75
FES	503	98	(79)	(63)	43

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

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, 2015 and December 31, 2014:

	September 30, 2015			December 31, 2014		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
	(In millions)					
Debt Securities						
FirstEnergy	$10	$2	$12	$13	$4	$17

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 $623 million as of September 30, 2015 and $626 million as of December 31, 2014, 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, 2015		December 31, 2014	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
FirstEnergy	$20,118	$21,525	$19,828	$21,733
FES	3,054	3,135	3,097	3,241

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, 2015 and December 31, 2014.

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 related 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) as follows:

- Changes in the fair value of derivative instruments that are designated and qualify as cash flow hedges are recorded to AOCI with subsequent reclassification to earnings in the period during which the hedged forecasted transaction affects earnings.
- Changes in the fair value of derivative instruments that are designated and qualify as fair value hedges are recorded as an adjustment to the item being hedged. When fair value hedges are discontinued, the adjustment recorded to the item being hedged is amortized into earnings.
- Changes in the fair value of derivative instruments that are not designated in a hedging relationship are recorded in earnings on a mark-to-market basis, unless otherwise noted.

Derivative instruments meeting the normal purchases and normal sales criteria are accounted for under the accrual method of accounting with their effects included in earnings at the time of contract performance.

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.

Total pre-tax net unamortized losses included in AOCI associated with instruments previously designated as cash flow hedges totaled $10 million and $8 million as of September 30, 2015 and December 31, 2014, respectively. Since the forecasted transactions remain probable of occurring, these amounts will be amortized into earnings over the life of the hedging instruments. Approximately $1 million of net unamortized losses is expected to be amortized to income during the next twelve months.

FirstEnergy has used forward starting interest rate 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 designated 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. Total pre-tax unamortized losses included in AOCI associated with prior interest rate cash flow hedges totaled $44 million and $50 million as of September 30, 2015 and December 31, 2014, respectively. Based on current estimates, approximately $9 million of these unamortized losses is expected to be amortized to interest expense during the next twelve months.

Refer to Note 5, Accumulated Other Comprehensive Income, for reclassifications from AOCI during the three and nine months ended September 30, 2015 and 2014.

As of September 30, 2015 and December 31, 2014, no commodity or interest rate derivatives were designated as cash flow hedges.

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. As of September 30, 2015 and December 31, 2014, 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 $23 million and $32 million as of September 30, 2015 and December 31, 2014, respectively. During the next twelve months, approximately $11 million of unamortized gains is expected to be amortized to interest expense. Amortization of unamortized gains included in long-term debt totaled approximately $3 million during the three months ended September 30, 2015 and 2014 and $9 million during the nine months ended September 30, 2015 and 2014.

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, 2015, FirstEnergy’s net asset position under commodity derivative contracts was $86 million, which related to FES positions. Under these commodity derivative contracts, FES posted $30 million of collateral. Certain commodity derivative contracts include credit risk related contingent features that would require FES to post $2 million of additional collateral if the credit rating for its debt were to fall below investment grade.

Based on commodity derivative contracts held as of September 30, 2015, an adverse change of 10% in commodity prices would increase net income by approximately $27 million during the next twelve months.

NUGs

As of September 30, 2015, FirstEnergy's net liability position under NUG contracts was $143 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.

FTRs

As of September 30, 2015, FirstEnergy's and FES' FTR position was a $3 million net asset and a $2 million net liability, respectively, and FES posted $6 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 PJM that have load serving obligations and through the direct allocation of FTRs from PJM. PJM 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 PJM, 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	Fair Value September 30, 2015	December 31, 2014	Derivative Liabilities	Fair Value September 30, 2015	December 31, 2014
	(In millions)			(In millions)	
Current Assets - Derivatives			Current Liabilities - Derivatives		
Commodity Contracts	$140	$121	Commodity Contracts	$(111)	$(154)
FTRs	16	38	FTRs	(13)	(13)
	156	159		(124)	(167)
Deferred Charges and Other Assets - Other			Noncurrent Liabilities - Adverse Power Contract Liability		
			NUGs[1]	(144)	(153)
Commodity Contracts	116	51	Noncurrent Liabilities - Other		
FTRs	1	1	Commodity Contracts	(59)	(13)
NUGs[1]	1	2	FTRs	(1)	(1)
	118	54		(204)	(167)
Derivative Assets	$274	$213	Derivative Liabilities	$(328)	$(334)

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

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, 2015	Fair Value	Derivative Instruments	Cash Collateral (Received)/Pledged	Net Fair Value
	(In millions)			
Derivative Assets				
Commodity contracts	$256	$(163)	$—	$93
FTRs	17	(14)	—	3
NUG contracts	1	—	—	1
	$274	$(177)	$—	$97
Derivative Liabilities				
Commodity contracts	$(170)	$163	$4	$(3)

FTRs	(14)	14	—	—
NUG contracts	(144)	—	—	(144)
	$(328)	$177	$4	$(147)

		Amounts Not Offset in Consolidated Balance Sheet		
December 31, 2014	Fair Value	Derivative Instruments	Cash Collateral (Received)/Pledged	Net Fair Value
	(In millions)			
Derivative Assets				
Commodity contracts	$172	$(126)	$—	$46
FTRs	39	(14)	—	25
NUG contracts	2	—	—	2
	$213	$(140)	$—	$73
Derivative Liabilities				
Commodity contracts	$(167)	$126	$35	$(6)
FTRs	(14)	14	—	—
NUG contracts	(153)	—	—	(153)
	$(334)	$140	$35	$(159)

The following table summarizes the volumes associated with FirstEnergy’s outstanding derivative transactions as of September 30, 2015:

	Purchases	Sales	Net	Units
	(In millions)			
Power Contracts	19	57	(38)	MWH
FTRs	42	—	42	MWH
NUGs	5	—	5	MWH
Natural Gas	45	—	45	mmBTU

The effect of active derivative instruments not in a hedging relationship on FirstEnergy's Consolidated Statements of Income during the three and nine months ended September 30, 2015 and 2014, are summarized in the following tables:

	Three Months Ended September 30,		
	Commodity Contracts	FTRs	Total
	(In millions)		
2015			
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense [1]	$59	$(2)	$57
Realized Gain (Loss) Reclassified to:			
Revenues [2]	$41	$2	$43
Purchased Power Expense [3]	(50)	—	(50)
Other Operating Expense [4]	—	(11)	(11)
Fuel Expense	(5)	—	(5)

[1] Includes $59 million for commodity contracts and ($2) million for FTRs associated with FES.
[2] Includes $41 million for commodity contacts and $2 million for FTRs associated with FES.
[3] Includes ($50) million for commodity contracts associated with FES.
[4] Includes ($11) million for FTRs associated with FES.

	Three Months Ended September 30,		
	Commodity Contracts	FTRs	Total
	(In millions)		
2014			
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense [5]	$(24)	$4	$(20)
Realized Gain (Loss) Reclassified to:			
Revenues [6]	$3	$11	$14
Purchased Power Expense [7]	(63)	—	(63)
Other Operating Expense [8]	—	(13)	(13)
Fuel Expense	(8)	—	(8)

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

	Nine Months Ended September 30,			
	Commodity Contracts	FTRs	Interest Rate Swaps	Total
2015	(In millions)			
Unrealized Gain (Loss) Recognized in:				
Other Operating Expense[1]	$81	$(17)	$—	$64
Realized Gain (Loss) Reclassified to:				
Revenues[2]	$48	$48	$—	$96
Purchased Power Expense[3]	(78)	—	—	(78)
Other Operating Expense[4]	—	(38)	—	(38)
Fuel Expense	(26)	—	—	(26)

[1] Includes $81 million for commodity contracts and ($16) million for FTRs associated with FES.
[2] Includes $48 million for commodity contracts and $46 million for FTRs associated with FES.
[3] Includes ($78) million for commodity contracts associated with FES.
[4] Includes ($37) 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[5]	$(82)	$22	$—	$(60)
Realized Gain (Loss) Reclassified to:				
Revenues[6]	$(8)	$62	$—	$54
Purchased Power Expense[7]	395	—	—	395
Other Operating Expense[8]	—	(30)	—	(30)
Fuel Expense	3	—	—	3
Interest Expense	—	—	6	6

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

The following table provides a reconciliation of changes in the fair value of FirstEnergy's derivative instruments subject to regulatory accounting during the three and nine months ended September 30, 2015 and 2014. Changes in the value of these instruments are deferred for future recovery from (or credit to) customers:

	Three Months Ended September 30,		
Derivatives Not in a Hedging Relationship with Regulatory Offset	NUGs	Regulated FTRs	Total
	(In millions)		
Outstanding net asset (liability) as of July 1, 2015	$(140)	$12	$(128)
Unrealized loss	(20)	(4)	(24)
Settlements	17	(3)	14
Outstanding net asset (liability) as of September 30, 2015	$(143)	$5	$(138)
Outstanding net asset (liability) as of July 1, 2014	$(169)	$10	$(159)
Unrealized gain (loss)	(9)	6	(3)
Settlements	23	(5)	18
Outstanding net asset (liability) as of September 30, 2014	$(155)	$11	$(144)

	Nine Months Ended September 30,		
Derivatives Not in a Hedging Relationship with Regulatory Offset	NUGs	Regulated FTRs	Total
	(In millions)		
Outstanding net asset (liability) as of January 1, 2015	$(151)	$11	$(140)
Unrealized loss	(36)	(3)	(39)
Purchases	—	12	12
Settlements	44	(15)	29
Outstanding net asset (liability) as of September 30, 2015	$(143)	$5	$(138)
Outstanding net liability as of January 1, 2014	$(202)	$—	$(202)
Unrealized gain	17	10	27
Purchases	—	11	11
Settlements	30	(10)	20
Outstanding net asset (liability) as of September 30, 2014	$(155)	$11	$(144)

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 SOS supply for PE customers have expired, service continues in the same manner until changed by order of the MDPSC. 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, and requiring each electric utility to file a plan every three years. PE's current plan, covering the three-year period 2015-2017, was approved by the MDPSC on December 23, 2014. The costs of the 2015-2017 plan are expected to be approximately $66 million for that three-year period, of which $13 million was incurred through September 2015. On July 16, 2015, the MDPSC issued an order setting new incremental energy savings goals for 2017 and beyond, beginning with the level of savings achieved under PE's current plan for 2016, and ramping up 0.2% per year thereafter to reach 2%. 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.

On February 27, 2013, the MDPSC issued an order (the February 27 Order) requiring the Maryland electric utilities to submit analyses relating to the costs and benefits of making further system and staffing enhancements in order to attempt to reduce storm outage durations. The order further required the Staff of the MDPSC to report on possible performance-based rate structures and to propose additional rules relating to feeder performance standards, outage communication and reporting, and sharing of special needs customer information. PE's responsive filings 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 of the MDPSC 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 of the MDPSC. In addition, the Staff of the MDPSC 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 issued a ruling on any of those matters.

On March 3, 2014, pursuant to the MDPSC's regulations, PE filed its recommendations for SAIDI and SAIFI standards to apply during the period 2016-2019. The MDPSC directed the Staff of the MDPSC to file an analysis and recommendations with respect to the proposed 2016-2019 SAIDI and SAIFI standards and any related rule changes which the Staff of the MDPSC recommended. The Staff of the MDPSC made its filing on July 10, 2015, and recommended that PE be required to improve its SAIDI results by approximately 20% by 2019. The MDPSC held a hearing on the Staff's analysis and recommendations on September 1-2, 2015, and approved PE's revised proposal for an improvement of 8.6% in its SAIDI standard by 2019 and maintained its SAIFI standard at 2015 levels.

On April 1, 2015, PE filed its annual report on its performance relative to various service reliability standards set forth in the MDPSC’s regulations. The MDPSC held a hearing on the reports filed by PE and the other electric utilities in Maryland on August 24, 2015, and has not yet issued an order on this matter.

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 is comprised of two components, procured through separate, annually held descending clock auctions, the results of which are approved by the NJBPU. One BGS component reflects hourly real time energy prices and is available for larger commercial and industrial customers. The second BGS component provides a fixed price service and is intended for smaller commercial and residential customers. All New Jersey EDCs participate in this competitive BGS procurement process and recover BGS costs directly from customers as a charge separate from base rates.

On March 26, 2015, the NJBPU entered final orders which together provided an overall reduction in JCP&L's annual revenues of approximately $34 million, effective April 1, 2015. The final order in JCP&L's base rate case proceeding directed an annual base rate revenue reduction of approximately $115 million, including recovery of 2011 storm costs and the application of the NJBPU's modified CTA policy approved in the generic CTA proceeding referred to below. Additionally, the final order in the generic proceeding established to review JCP&L's major storm events of 2011 and 2012 approved the recovery of 2012 storm costs of $580 million resulting in an increase in annual revenues of approximately $81 million. JCP&L is required to file another base rate case no later than April 1, 2017. The NJBPU also directed that certain studies be completed. On July 22, 2015, the NJBPU approved the NJBPU staff's recommendation to implement such studies, which will include operational and financial components and is expected to take approximately one year to complete.

In an Order issued October 22, 2014, in a generic proceeding to review its policies with respect to the use of a CTA in base rate cases (Generic CTA proceeding), the NJBPU stated that it would continue to apply its current CTA policy in base rate cases, subject to incorporating the following modifications: (i) calculating savings using a five-year look back from the beginning of the test year; (ii) allocating savings with 75% retained by the company and 25% allocated to rate payers; and (iii) excluding transmission assets of electric distribution companies in the savings calculation. On November 5, 2014, the Division of Rate Counsel appealed the NJBPU Order regarding the Generic CTA proceeding to the New Jersey Superior Court and JCP&L has filed to participate as a respondent in that proceeding. Briefing has been completed, and oral argument has not yet been scheduled.

On June 19, 2015, JCP&L, along with PN, ME, FET and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT, a new transmission-only subsidiary of FET. Evidentiary hearings are scheduled to commence before the NJBPU in February 2016. A final decision from the NJBPU is expected by mid-2016. See Transfer of Transmission Assets to MAIT in FERC Matters below for further discussion of this transaction.

OHIO

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

- Continuing the current base distribution rate freeze through May 31, 2016;
- Continues collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs;
- Continuing to provide economic development and assistance to low-income customers for the two-year plan period at levels established in the prior ESP;
- A 6% generation rate discount to certain low income customers provided by the Ohio Companies through a bilateral wholesale contract with FES (FES is one of the wholesale suppliers to the Ohio Companies);
- Continuing to provide power to non-shopping customers at a market-based price set through an auction process;
- Continuing Rider DCR that allows continued investment in the distribution system for the benefit of customers;
- Continuing commitment not to recover from retail customers certain costs related to transmission cost allocations for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of costs avoided by customers for certain types of products totals $360 million, subject to the outcome of certain FERC proceedings;
- Securing generation supply for a longer period of time by conducting an auction for a three-year period rather than a one-year period, in each of October 2012 and January 2013, to mitigate any potential price spikes for the Ohio Companies' utility customers who do not switch to a competitive generation supplier; and
- Extending the recovery period for costs associated with purchasing RECs mandated by SB221, Ohio's renewable energy and energy efficiency standard, through the end of the new ESP 3 period. This is expected to initially reduce the monthly renewable energy charge for all non-shopping utility customers of the Ohio Companies by spreading out the costs over the entire ESP period.

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

The Ohio Companies filed an application with the PUCO on August 4, 2014 seeking approval of their ESP IV entitled Powering Ohio's Progress. The Ohio Companies filed a partial Stipulation and Recommendation on December 22, 2014, a Supplemental Stipulation and Recommendation on May 28, 2015, and a Second Supplemental Stipulation and Recommendation on June 4, 2015. The evidentiary hearing on the ESP IV commenced on August 31, 2015.

The material terms of the proposed plan as filed include:

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

- General updates to electric service regulations and tariffs to reflect regulatory orders, administrative rule changes, and current practices.

On September 18, 2015, PUCO Staff filed testimony addressing various issues within the Ohio Companies’ filing, including a recommendation that the PUCO deny the request for approval of a retail rate stability rider as proposed by the Ohio Companies, but PUCO Staff also stated that the retail rate stability rider may be in the public interest if its recommended changes are adopted. Briefs are due November 30, 2015, and reply briefs are due December 22, 2015. A final decision of the PUCO is expected early in 2016.

Under Ohio's energy efficiency standards (SB221 and SB310), and based on the Ohio Companies' amended energy efficiency plans, the Ohio Companies are required to implement energy efficiency programs that achieve a total annual energy savings equivalent of 2,266 GWHs in 2015 and 2,288 GWHs in 2016, and then begin to increase by 1% each year in 2017, subject to the outcome of a legislative study committee. The Ohio Companies are also required to retain the 2014 peak demand reduction level for 2015 and 2016 and then increase the benchmark by an additional 0.75% thereafter through 2020, subject to the outcome of a legislative study committee. On September 30, 2015, the Energy Mandates Study Committee issued its report related to energy efficiency and renewable energy mandates, recommending that the current level of mandates remain in place indefinitely. The report also recommended: (i) an expedited process for review of utility proposed energy efficiency plans; (ii) ensuring maximum credit for all of Ohio's Energy Initiatives; (iii) a switch from energy mandates to energy incentives; and (iv) a declaration be made that the General Assembly may determine energy policy of the state.

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

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

Ohio law requires electric utilities and electric service companies in Ohio to serve part of their load from renewable energy resources measured by an annually increasing percentage amount through 2026, subject to the outcome of a legislative study committee, except 2015 and 2016 that remain at the 2014 level. The Ohio Companies conducted RFPs in 2009, 2010 and 2011 to secure RECs to help meet these renewable energy requirements. In September 2011, the PUCO opened a docket to review the Ohio Companies' alternative energy recovery rider through which the Ohio Companies recover the costs of acquiring these RECs. The PUCO issued an Opinion and Order on August 7, 2013 approving the Ohio Companies' acquisition process and their purchases of RECs to meet statutory mandates in all instances except for part of the purchases arising from one auction and directing the Ohio Companies to credit non-shopping customers in the amount of $43.4 million, plus interest, on the basis that the Ohio Companies did not prove such purchases were prudent. On December 24, 2013, following the denial of their application for rehearing, the Ohio Companies filed a notice of appeal and a motion for stay of the PUCO's order with the Supreme Court of Ohio, which was granted. On February 18, 2014, the OCC and the ELPC also filed appeals of the PUCO's order. The Ohio Companies timely filed their merit brief with the Supreme Court of Ohio and the briefing process has concluded. The matter is not yet scheduled for oral argument.

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

PENNSYLVANIA

The Pennsylvania Companies currently operate under DSPs that expire on May 31, 2017, 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 spot market purchases, quarterly descending clock auctions for 3, 12- and 24-month energy contracts, and one RFP seeking 2-year contracts to serve SRECs for ME, PN, and Penn.

Pursuant to Pennsylvania's EE&C legislation (Act 129 of 2008) and PPUC orders, Pennsylvania EDC's implement energy efficiency and peak demand reduction programs. The Pennsylvania Companies' Phase II EE&C Plans are effective through May 31, 2016. Total costs of these plans are expected to be approximately $234 million and recoverable through the Pennsylvania Companies' reconcilable EE&C riders. On June 19, 2015, the PPUC issued a Phase III Final Implementation Order setting: demand reduction targets, relative to each Pennsylvania Companies' 2007-2008 peak demand (in MW), at 1.8% for ME, 1.7% for Penn, 1.8% for WP, and 0% for PN; and energy consumption reduction targets, as a percentage of each Pennsylvania Companies' historic 2010 forecasts (in MWH), at 4.0% for ME, 3.9% for PN, 3.3% for Penn, and 2.6% for WP. The Pennsylvania Companies expect to file their Phase III EE&C plans for the June 2016 through May 2021 period by November 30, 2015. EDCs are permitted to recover costs for implementing Phase III EE&C plans.

Pursuant to Act 11 of 2012, Pennsylvania EDCs may establish a DSIC to recover costs of infrastructure improvements and costs related to highway relocation projects with PPUC approval. Pennsylvania EDCs must file LTIIPs outlining infrastructure improvement plans for PPUC review and approval prior to approval of a DSIC. On October 19, 2015, each of the Pennsylvania Companies filed LTIIPs with the PPUC for infrastructure improvement over the five-year period of 2016 to 2020 for the following costs: WP $88.34 million; PN $56.74 million; Penn $56.35 million; and ME $43.44 million. These amounts include all qualifying distribution capital additions identified in the revised implementation plan for the recent focused management and operations audit of the Pennsylvania Companies. Following PPUC approval of the LTIIPs, the Pennsylvania Companies will submit DSIC tariffs for approval for quarterly recovery of approved costs.

Each of the Pennsylvania Companies currently offer distribution rates under their respective Joint Petitions for Settlement approved on April 9, 2015 by the PPUC, which, among other things, provide for a total increase in annual revenues for all Pennsylvania Companies of $292.8 million, ($89.3 million for ME, $90.8 million for PN, $15.9 million for Penn and $96.8 million for WP), including the recovery of $87.7 million of additional annual operating expenses, including costs associated with service reliability enhancements to the distribution system, amortization of deferred storm costs and the remaining net book value of legacy meters, assistance for providing service to low-income customers, and the creation of a storm reserve for each utility. Additionally, the settlements include commitments to meet certain wait times for call centers and service reliability standards. The new rates were effective May 3, 2015.

On July 16, 2013, the PPUC's Bureau of Audits initiated a focused management and operations audit of the Pennsylvania Companies as required every eight years by statute. The PPUC issued a report on its findings and recommendations on February 12, 2015, at which time the Pennsylvania Companies' associated implementation plan was also made public. In an order issued on March 30, 2015, the Pennsylvania Companies were directed to develop and file by May 29, 2015 revised implementation plans regarding certain of the operational topics addressed in the report, including addressing certain reliability matters. On May 19, 2015, the PPUC granted a forty-five day extension for the filing of revised implementation plans with respect to certain of the matters raised in its March 30, 2015 Order. On May 29, 2015 and July 13, 2015, the Pennsylvania Companies filed their revised implementation plan. On August 20, 2015, the PPUC issued a Tentative Order accepting the Pennsylvania Companies’ revised plan as being in the public interest and seeking public comment. The OCA submitted comments on September 21, 2015, generally supportive of the Pennsylvania Companies’ revised plan as being complementary with the commitments made in the recent base rate case proceedings. The Pennsylvania Companies filed a limited reply on October 13, 2015, and a Final Order is pending. The cost of compliance for the Pennsylvania Companies is currently expected to range from approximately $200 million to $230 million.

On June 19, 2015, ME and PN, along with JCP&L, FET and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT, a new transmission-only subsidiary of FET. Evidentiary hearings are scheduled to commence before the PPUC on February 29, 2016. A final decision from the PPUC is expected by mid-2016. See Transfer of Transmission Assets to MAIT in FERC Matters below for further discussion of this transaction.

WEST VIRGINIA

MP and PE currently operate under a Joint Stipulation and Agreement of Settlement approved by the WVPSC on February 3, 2015, that provides for: a $15 million increase in base rate revenues effective February 25, 2015; the implementation of a Vegetation Management Surcharge to recover all costs related to both new and existing vegetation maintenance programs; authority to establish a regulatory asset for MATS investments placed into service in 2016 and 2017; authority to defer, amortize and recover over a 5-year period approximately $46 million of storm restoration costs; and elimination of the TTS for costs associated with MP's acquisition of the Harrison plant in October 2013 and movement of those costs into base rates. MP and PE's current ENEC rates went into effect on February 25, 2015, in accordance with a settlement approved by the WVPSC on January 29, 2015.

On August 14, 2015, MP and PE filed their annual ENEC case with the WVPSC proposing an approximate $165.1 million annual increase in rates effective January 1, 2016 or before, which is a 12.5% overall increase over existing rates and remains subject to WVPSC approval. The proposed increase is comprised of a $97 million under-recovered balance as of June 30, 2015, a projected $23.7 million under-recovery for the 2016 calendar year, and an actual under-recovered balance from MP and PE's TTS for Harrison Power Station of $44.4 million. On September 10, 2015, MP and PE filed an amendment addressing the results of the recent PJM Transitional Auctions for Capacity Performance, which resulted in a net decrease of $20.6 million from the initial requested increase to $144.5 million. A hearing has been set for November 19-20, 2015 with an order expected to be issued before the end of 2015 for rates effective by January 1, 2016.

On August 31, 2015, MP and PE filed with the WVPSC their biennial petition for reconciliation of the Vegetation Management Program Surcharge and regular review of the program proposing an approximate $37.7 million annual increase in rates, which is a 2.8% overall increase over existing rates and remains subject to WVPSC approval. The proposed increase is comprised of a $2.1 million under-recovered balance as of June 30, 2015, a projected $23.9 million in under-recovery for the 2016/2017 rate effective period, and recovery of previously authorized deferred vegetation management costs from April 14, 2014 through February 24, 2015 in the amount of $49.9 million. Hearings are scheduled for November 19-20, 2015 and a final order is expected to be issued before the end of 2015 for rates effective by January 1, 2016.

RELIABILITY MATTERS

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

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

FERC MATTERS

PJM Transmission Rates

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

The PJM transmission owners, including FirstEnergy, submitted filings to FERC setting forth the cost allocation method under Order No. 1000 for projects that cross the borders between the PJM Region and: (i) the NYISO region; (ii) the MISO region; and (iii) the FERC-jurisdictional members of the SERTP region. These filings propose to allocate the costs of these interregional transmission projects based on the costs of projects that otherwise would have been constructed separately in each region, or, in the case of MISO, based on 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. As of May 14, 2015, FERC has accepted the PJM/NYISO, PJM/MISO and PJM/SERTP filings, subject to further compliance requirements. FERC’s acceptance of the PJM/SERTP filing is also subject to refund and the SERTP region participants’ related Order No. 1000 interregional compliance proceedings.

In a series of orders in certain Order No. 1000 dockets, FERC 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 the question of whether FirstEnergy and the PJM transmission owners have a "right of first refusal" is now pending before the U.S. Court of Appeals for the D.C. Circuit in an appeal of FERC's order approving PJM's Order No.1000 compliance filing.

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

RTO Realignment

On June 1, 2011, ATSI and the ATSI zone transferred from MISO to PJM. While many of the matters involved with the move have been resolved, FERC denied recovery under ATSI's transmission rate for certain charges that collectively can be described as "exit fees" and certain other transmission cost allocation charges totaling approximately $78.8 million until such time as ATSI submits a cost/benefit analysis demonstrating net benefits to customers from the move. Subsequently, FERC rejected a proposed settlement agreement to resolve the exit fee and transmission cost allocation issues, stating that its action is without prejudice to ATSI submitting a cost/benefit analysis demonstrating that the benefits of the RTO realignment decisions outweigh the exit fee and transmission cost allocation charges. FirstEnergy's request for rehearing of FERC's order rejecting the settlement agreement 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 United States appellate courts. In the event of a final non-appealable order that rules that ATSI must pay these charges, ATSI will seek recovery of these charges through its formula rate. On a related issue, FirstEnergy joined certain other PJM transmission owners in a protest of MISO's proposal to allocate MVP costs to energy transactions that cross MISO's borders into the PJM Region. On January 22, 2015, FERC issued an order establishing a paper hearing on remand from the Seventh Circuit of the issue of whether any limitation on "export pricing" for sales of energy from MISO into PJM is justified in light of applicable FERC precedent. On April 22, 2015, certain PJM transmission owners, including FirstEnergy, filed an initial brief asserting that FERC’s prior ruling rejecting MISO’s proposed MVP export charge on transactions into PJM was correct and should be re-affirmed on remand. Reply comments were filed June 22, 2015. The matter is now before FERC for consideration.

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

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

2014 ATSI Formula Rate Filing

On October 31, 2014, ATSI filed a proposal with FERC to change the structure of its formula rate. The proposed change requested to move from an “historical looking” approach, where transmission rates reflect actual costs for the prior year, to a “forward looking” approach, where transmission rates would be based on the estimated costs for the coming year, with an annual true up. On December 31, 2014, FERC issued an order accepting ATSI's filing effective January 1, 2015, as requested, subject to refund and the outcome of hearing and settlement proceedings. FERC also initiated an inquiry pursuant to Section 206 of the FPA into ATSI's ROE and certain other matters, with a refund effective date of January 12, 2015, for any refund resulting from the inquiry. On July 20, 2015, ATSI and certain parties filed a settlement agreement with FERC, which remains subject to FERC approval. The agreement provides for certain changes to ATSI's proposed forward-looking formula rate template and protocols, and also changes ATSI's ROE from 12.38% to the following values: (i) 12.38% for the period commencing January 1, 2015 through June 30, 2015; (ii) 11.06% for the period commencing July 1, 2015 through December 31, 2015; and (iii) 10.38% for the period commencing January 1, 2016. The 10.38% ROE value will remain in effect unless changed pursuant to section 205 or 206 of the FPA provided the effective date for any change cannot be earlier than January 1, 2018. The agreement currently is pending at FERC and ATSI anticipates that it will be approved later this year.

Transfer of Transmission Assets to MAIT

On June 10, 2015, MAIT, a Delaware limited liability company, was formed as a new transmission-only subsidiary of FET for the purposes of owning and operating all FERC-jurisdictional transmission assets of JCP&L, ME and PN following the receipt of all necessary state and federal regulatory approvals. On June 19, 2015, JCP&L, PN, ME, FET, and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT. Additionally, the filings requested approval from the NJBPU and PPUC, as applicable, of; (i) a lease to MAIT of real property and rights-of-way associated with the utilities' transmission assets; (ii) a Mutual Assistance Agreement; (iii) MAIT being deemed a public utility under state laws; (iv) MAIT's participation in FE's regulated companies' money pool; and (v) certain affiliated interest agreements. If approved, JCP&L, ME, and PN will contribute their transmission assets at net book value and an allocated portion of goodwill in a tax-free exchange to MAIT, which will operate similar to FET's two existing stand-alone transmission subsidiaries, ATSI and TrAIL. MAIT's transmission facilities will remain under the functional control of PJM, and PJM will provide transmission service using these facilities under the PJM Tariff. During the third quarter of 2015, FirstEnergy responded to FERC Staff's request for additional information regarding the application. FERC approval is expected in early-2016 with final decisions expected from the NJBPU and PPUC by mid-2016. Following FERC approval of the transfer, MAIT expects to file a Section 204 application with FERC, and other necessary filings with the PPUC and the NJBPU, seeking authorization to issue equity to FET, JCP&L, PN and ME for their respective asset contributions, and to issue debt. MAIT will also make a Section 205 formula rate application with FERC to establish its transmission rate.

California Claims Matters

In October 2006, several California governmental and utility parties presented AE Supply with a settlement proposal to resolve alleged overcharges for power sales by AE Supply to the California Energy Resource Scheduling division of the CDWR during 2001. The settlement proposal claims that CDWR is owed approximately $190 million for these alleged overcharges. This proposal was made in the context of mediation efforts by FERC and the Ninth Circuit in several pending proceedings to resolve all outstanding refund and other claims, including claims of alleged price manipulation in the California energy markets during 2000 and 2001. The Ninth Circuit had previously remanded one of those proceedings to FERC, which dismissed the claims of the California Parties in May 2011. The California Parties appealed FERC's decision back to the Ninth Circuit. AE Supply joined with other intervenors in the case and filed a brief in support of FERC's dismissal of the case. On April 29, 2015, the Ninth Circuit issued a decision remanding the case to FERC for further proceedings.

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

FirstEnergy cannot predict the outcome of either of the above matters or estimate the possible loss or range of loss.

PATH Transmission Project

On August 24, 2012, the PJM Board of Managers canceled the PATH project, a proposed transmission line from West Virginia through Virginia and into Maryland which PJM had previously suspended in February 2011. As a result of PJM canceling the project, approximately $62 million and approximately $59 million in costs incurred by PATH-Allegheny and PATH-WV (an equity method investment for FE), respectively, were reclassified from net property, plant and equipment to a regulatory asset for future recovery. PATH-Allegheny and PATH-WV requested authorization from FERC to recover the costs with a proposed ROE of 10.9% (10.4% base plus 0.5% for RTO membership) from PJM customers over five years. FERC issued an order denying the 0.5% ROE adder for RTO membership and allowing the tariff changes enabling recovery of these costs to become effective on December 1, 2012, subject to settlement proceedings and hearing if the parties could not agree to a settlement. On March 24, 2014, the FERC Chief ALJ terminated settlement proceedings and appointed an ALJ to preside over the hearing phase of the case, including discovery and additional pleadings leading up to hearing, which subsequently included the parties addressing the application of FERC's Opinion No. 531, discussed below, to the PATH proceeding. The hearing concluded on April 22, 2015. On September 14, 2015, the ALJ issued his initial decision, disallowing recovery of certain costs (primarily relating to advertising and losses on real property) and finding that PATH's ROE for the five-year recovery period should be set at 6.27%. The proceedings have now moved to the exception phase with briefs on exceptions filed on October 14, 2015, and briefs opposing exceptions due November 3, 2015. The initial decision and exception briefs will then be before FERC for review and a final order. FirstEnergy continues to believe the costs are recoverable, subject to final ruling from FERC.

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 the potential for 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 forecast based on a forecast for the U.S. economy (1/3 weight). Regarding the qualitative adjustment, for single-utility rate cases FERC formerly pegged ROE at the median 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. On October 16, 2014, FERC issued its Opinion No. 531-A, applying the revised ROE methodology to certain ISO New England transmission owners. On March 3, 2015, FERC issued Opinion No. 531-B affirming its prior rulings. Appeals of Opinion Nos. 531, 532-A and 531-B are pending before the U.S. Court of Appeals for the D.C. Circuit. 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.

MISO Capacity Portability

On June 11, 2012, in response to certain arguments advanced by MISO, FERC issued a Notice of Request for Comments regarding whether existing rules on transfer capability act as barriers to the delivery of capacity between MISO and PJM. FirstEnergy and other parties have submitted filings arguing that MISO's concerns largely are without foundation and suggested that FERC address the remaining concerns in the existing stakeholder process that is described in the PJM/MISO Joint Operating Agreement. FERC has not mandated a solution, and the RTOs and affected parties are working to address the MISO's proposal in stakeholder proceedings. In January 2015, the RTOs and affected parties indicated to FERC that discussions on the various issues are continuing. At FERC's direction, on May 12 and 13, 2015, PJM, MISO, and their respective independent market monitors provided additional information on their various joint issues surrounding the PJM/MISO seam, including capacity portability, to assist the FERC's understanding of the issues and what, if any, additional steps FERC should take to improve the efficiency of operations at the PJM/MISO seam. Stakeholders, including FESC on behalf of certain of its affiliates and as part of a coalition of certain other PJM utilities, filed responses to the RTO submissions. The various submissions and responses are now before FERC for consideration.

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.

Synchronous Condensers

On December 20, 2012, FERC approved the transfer by FG to ATSI of certain deactivated generation assets associated with Eastlake Units 1 through 5 to facilitate their conversion to synchronous condensers to provide voltage support on the ATSI transmission system. The transfer of Eastlake Units 4-5 was completed on January 31, 2013, and the transfer of Eastlake Units 1-3 was completed on April 30, 2015.

FTR Underfunding Complaint

In PJM, FTRs are a mechanism to hedge congestion and operate as a financial replacement for physical firm transmission service. FTRs are financially-settled instruments that entitle the holder to a stream of revenues based on the hourly congestion price differences across a specific transmission path in the PJM Day-ahead Energy Market. FE also performs bilateral transactions for the purpose of hedging the price differences between the location of supply resources and retail load obligations. Due to certain language in the PJM Tariff, the funds that are set aside to pay FTRs can be diverted to other uses, which may result in "underfunding" of FTR payments. FES and AE Supply continue to evaluate proposals to address issues with FTR allocation and funding.

On February 15, 2013, FES and AE Supply filed a renewed complaint with FERC for the purpose of changing the PJM Tariff to eliminate FTR underfunding. On June 5, 2013, FERC issued an order denying the new complaint and on June 8, 2015, denied a request for rehearing of the June 5, 2013 order.

A recent and related issue is the effect that certain financial trades have on congestion. On August 29, 2014, FERC instituted an investigation to address the question of whether the current rules regarding "Up-to Congestion" transactions are just and reasonable. FESC, on behalf of FES and the Utilities, filed comments supporting the investigation, arguing that PJM Tariff changes would decrease the incidence of Up-to Congestion transactions, and funding for FTRs likely would increase. FERC convened a technical conference on January 7, 2015 to discuss application of certain FTR-related rules to Up-to Congestion. On October 19, 2015, PJM submitted two filings to further adjust its FTR tariffs. Comments are due on November 9, 2015. FE is evaluating PJM's filings.

PJM Market Reform: 2014 PJM RPM Tariff Amendments

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

PJM Market Reform: PJM Capacity Performance Proposal

In December 2014, PJM submitted proposed "Capacity Performance" reforms of its RPM capacity and energy markets. On June 9, 2015, FERC issued an order conditionally approving the bulk of the proposed Capacity Performance reforms with an effective date of April 1, 2015, and directed PJM to make a compliance filing reflecting the mandate of FERC's order. On July 9, 2015, several parties, including FESC on behalf of certain of its affiliates, submitted requests for rehearing for FERC's June 9, 2015 order, and PJM submitted its compliance filing as directed by the order. The requests for rehearing and PJM's compliance filing are pending before FERC.

Following FERC's issuance of the June 9, 2015 order on the Capacity Performance proposal, PJM conducted the 2015 BRA for the 2018/2019 delivery year on August 10-14, 2015, and reported a clearing price for Capacity Performance of $164.77/MW-day and a clearing price for base capacity of $149.98/MW-day in the Rest-of-RTO and ATSI regions. PJM conducted the Capacity Performance transition auction for the 2016/2017 delivery year on August 26-27, 2015, and reported an RTO-wide clearing price of $134.00/MW-day. PJM conducted the Capacity Performance transition auction for the 2017/2018 delivery year on September 3-4, 2015, and reported an RTO-wide clearing price of $151.50/MW-day. FirstEnergy's net competitive capacity position as a result of the BRA and Capacity Performance transition auctions is as follows:

2016 - 2017				2017 - 2018				2018 - 2019*			
Legacy Obligation		Capacity Performance		Legacy Obligation		Capacity Performance		Base Generation		Capacity Performance	
(MW)	($/MWD)	(MW)	($/MWD)	(MW)	($/MWD)	(MW)	($/MWD)	(MW)	($/MWD)	(MW)	($/MWD)

ATSI	2,765	$114.23	4,210	$134.00	375	$120.00	6,245	$151.50	—	$149.98	6,245	$164.77
RTO	875	$59.37	3,675	$134.00	985	$120.00	3,565	$151.50	240	$149.98	3,930	$164.77
All Other Zones	135	$119.13	—	$134.00	150	$120.00	—	$151.50	35	**	20	**
	3,775		7,885		1,510		9,810		275		10,195	

*Approximately 885 MWs remain uncommitted for the 2018/2019 delivery year.
**Base Generation: 10 MWs cleared at $200.21/MWD and 25 MWs cleared at $149.98/MWD. Capacity Performance: 5 MWs cleared at $215.00/MWD and 15 MWs cleared at $164.77/MWD.

FirstEnergy and other PJM market entities also are addressing PJM’s capacity market concerns in other FERC proceedings. On November 20, 2014, FERC issued an order directing each ISO/RTO to file a report with FERC outlining each region’s efforts to ensure fuel security. PJM filed its report on February 18, 2015, advising FERC that PJM’s Capacity Performance proposal would address fuel assurance issues. On March 20, 2015, FESC, on behalf of its affected affiliates and as part of a coalition, filed responsive comments demonstrating that significant improvements were needed for PJM’s Capacity Performance proposal to address fuel assurance issues. The comments are before FERC for review.

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

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

PJM Market Reform: FERC Order No. 745 - DR

On May 23, 2014, a divided three-judge panel of the U.S. Court of Appeals for the D.C. Circuit issued an opinion vacating FERC Order No. 745, which required that, under certain parameters, DR participating in organized wholesale energy markets be compensated at LMP. The majority concluded that DR is a retail service, and therefore falls under state, and not federal, jurisdiction, and that FERC, therefore, lacks jurisdiction to regulate DR. The majority also found that even if FERC had jurisdiction over DR, Order No. 745 would be arbitrary and capricious because, under its requirements, DR was inappropriately receiving a double payment (LMP plus the savings of foregone energy purchases). On May 4, 2015, the United States Supreme Court granted petitions for certiorari requesting review of the May 23, 2014 opinion, and heard oral argument on the issues on October 14, 2015. The U.S. Court of Appeals for the D.C. Circuit is withholding issuance of its mandate pending the United States Supreme Court's review on the merits.

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

PJM Market Reform: PJM 2014 Triennial RPM Review

The PJM Tariff obligates PJM to perform a thorough review of its RPM program every three years. On September 25, 2014, PJM filed proposed changes to the PJM Tariff as part of the latest review cycle. Among other adjustments, the filing included: (i) shifting the VRR curve one percentage point to the right, which would increase the amount of capacity supply that is procured in the RPM auctions and the clearing price; and (ii) a change to the index used for calculating the generation plant construction costs of the Net CONE formula for the future years between triennial reviews. On November 28, 2014, FERC accepted the PJM Tariff amendments as proposed, subject to a minor compliance requirement. PJM subsequently submitted the required compliance filing. On December 23, 2014, a coalition including FESC, on behalf of its affected affiliates, requested rehearing of FERC's order. On October 15, 2015, FERC issued an order denying rehearing and accepting PJM's compliance filing.

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, 2015, FirstEnergy's outstanding guarantees and other assurances aggregated approximately $3.7 billion, consisting of parental guarantees ($577 million), subsidiaries' guarantees ($2.1 billion), other guarantees ($300 million) and other assurances ($671 million).

Of this aggregate amount, substantially all relates to guarantees of wholly-owned consolidated entities of FirstEnergy. FES' debt obligations are generally guaranteed by its subsidiaries, FG and NG, and FES guarantees the debt obligations of each of FG and NG. Accordingly, present and future holders of indebtedness of FES, FG and NG would have claims against each of FES, FG and NG, regardless of whether their primary obligor is FES, FG or NG.

COLLATERAL AND CONTINGENT-RELATED FEATURES

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

Bilateral agreements and derivative instruments entered into by FE and its subsidiaries have margining provisions that require posting of collateral. Based on FES' power portfolio exposures as of September 30, 2015, FES has posted collateral, including LOC, of $223 million. The Regulated Distribution segment has posted collateral of $1 million.

These credit-risk-related contingent features, or the margining provisions within bilateral agreements, 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, which is the ability to secure additional collateral when needed, could be required.

Subsequent to the occurrence of a senior unsecured credit rating downgrade to below S&P's BBB- and Moody's Baa3, or a “material adverse event,” the immediate posting of collateral or accelerated payments may be required of FE or its subsidiaries. The following table discloses the additional credit contingent contractual obligations that may be required under certain events as of September 30, 2015:

Collateral Provisions	FES	AE Supply	Utilities	Total
	(In millions)			
Split Rating (One rating agency's rating below investment grade)	$195	$6	$51	$252
BB+/Ba1 Credit Ratings	$228	$6	$51	$285
Full impact of credit contingent contractual obligations	$321	$15	$51	$387

Excluded from the preceding table are the potential collateral obligations due to affiliate transactions between the Regulated Distribution segment and CES segment. As of September 30, 2015, 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 $11 million with affiliated parties.

OTHER COMMITMENTS AND CONTINGENCIES

FirstEnergy is a guarantor under a syndicated senior secured term loan facility due March 3, 2020, under which Global Holding borrowed $300 million. In addition to FirstEnergy, Signal Peak, Global Rail, Global Mining Group, LLC and Global Coal Sales Group, LLC, each being a direct or indirect subsidiary of Global Holding, continue to provide their joint and several guaranties of the obligations of Global Holding under the 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 under the current facility as collateral.

During the first quarter of 2015, a subsidiary of Global Holding eliminated its right to put 2 million tons annually through 2024 from the Signal Peak mine to FG in exchange for FirstEnergy extending its guarantee under Global

Holding's $300 million senior secured term loan facility through 2020, resulting in a pre-tax charge of $24 million. See Note 7, Variable Interest Entities, for additional information regarding FEV's investment in Global Holding.

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.

CSAPR requires reductions of NOx and SO_2 emissions in two phases (2015 and 2017), 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 July 28, 2015, the U.S. Court of Appeals for the D.C. Circuit ordered the EPA to reconsider caps on NOx and SO_2 emissions from power plants in 13 states, including Ohio, Pennsylvania and West Virginia. This follows the 2014 U.S. Supreme Court ruling generally upholding EPA's regulatory approach under the CSAPR, but questioning whether EPA required upwind states to reduce emissions by more than their contribution to air pollution in downwind states. Depending on how the EPA and the states implement the CSAPR, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

EPA tightened the primary and secondary NAAQS for ozone from the 2008 standard levels of 75 PPB to 70 PPB on October 1, 2015. EPA stated the vast majority of U.S. counties will meet the new 70 PPB standard by 2025 due to other federal and state rules and programs but will designate counties that fail to attain the new 2015 ozone NAAQS by October 1, 2017. States will then have roughly three years to develop implementation plans to attain the new 2015 ozone NAAQS. Depending on how the EPA and the states implement the new 2015 ozone NAAQS, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

MATS imposes emission limits for mercury, PM, and HCL for all existing and new fossil fuel 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 plants. 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 plants. On February 5, 2015, the OEPA granted an extension through April 16, 2016 for MATS compliance at the Bay Shore and Sammis plants. Nearly all spending for MATS compliance at Bay Shore and Sammis has been completed through 2014. In addition, an EPA enforcement policy document contemplates up to an additional year to achieve compliance, through April 2017, under certain circumstances for reliability critical units. On June 29, 2015, the United States Supreme Court reversed a U.S. Court of Appeals for the D.C. Circuit decision that upheld MATS, rejecting EPA's regulatory approach that costs are not relevant to the decision of whether or not to regulate power plant emissions under Section 112 of the Clean Air Act and remanded the case back to the U.S. Court of Appeals for the D.C. Circuit for further proceedings. Subject to the outcome of further proceedings before the U.S. Court of Appeals for the D.C. Circuit and how the MATS are ultimately implemented, FirstEnergy's total capital cost for compliance (over the 2012 to 2018 time period) is currently expected to be approximately $370 million (CES segment of $178 million and Regulated Distribution segment of $192 million), of which $176 million has been spent through September 30, 2015 ($66 million at CES and $110 million at Regulated Distribution).

Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 were deactivated in April 2015, which completes the deactivation of 5,429 MW of coal-fired plants since 2012.

On August 3, 2015, FG, a subsidiary of FES, submitted to the AAA office in New York, N.Y., a demand for arbitration and statement of claim against BNSF and CSX seeking a declaration that MATS constituted a force majeure that excuses FG's performance under its coal transportation contract with these parties. Specifically, the dispute arises from a contract for the transportation by BNSF and CSX of a minimum of 3.5 million tons of coal annually through 2025 to certain coal-fired power plants owned by FG that are located in Ohio. As a result of and in compliance with MATS, those plants were deactivated by April 16, 2015. In January 2012, FG notified BNSF and CSX that MATS constituted a force majeure event under the contract that excused FG's further performance. Separately, on August 4, 2015, BNSF and CSX submitted to the AAA office in Washington, D.C., a demand for arbitration and statement of claim against FG alleging that FG breached the contract and that FG's declaration of a force majeure under the contract is not valid and seeking damages including, but not limited to, lost profits under the contract through 2025. As part of its statement of claim, a right to liquidated damages is alleged. FirstEnergy and FES continue to believe that MATS constitutes a force majeure event under the contract as it relates to the deactivated plants and that FG's performance under the contract is therefore excused. FirstEnergy and FES intend to vigorously assert their position in the arbitration proceedings. If, however, the arbitration panel rules in favor of BNSF and CSX, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. FirstEnergy and FES are unable to estimate the loss or range of loss.

FG is also a party to another coal transportation contract covering the delivery of 2.5 million tons annually through 2025, a portion of which is to be delivered to another coal-fired plant owned by FG that was deactivated as a result of MATS. FG has asserted a defense of force majeure in response to delivery shortfalls to such plant under this contract as well. If FirstEnergy and FES fail to reach a resolution with the applicable counterparties to the contract, and if it were ultimately determined that, contrary to FirstEnergy's and FES' belief, the force majeure provisions of that contract do not excuse the delivery shortfalls, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. FirstEnergy and FES are unable to estimate the loss or range of loss.

As to both coal transportation agreements referenced above, FES paid in settlement approximately $70 million in liquidated damages for delivery shortfalls in 2014 related to its deactivated plants.

As to a specific coal supply agreement, FirstEnergy and AE Supply have asserted termination rights effective in 2015. In response to notification of the termination, the coal supplier commenced litigation alleging FirstEnergy and AE Supply do not have sufficient justification to terminate the agreement. FirstEnergy and AE Supply have filed an answer denying any liability related to the termination. There are 6 million tons remaining under the contract for delivery. At this time, FirstEnergy cannot estimate the loss or range of loss regarding the on-going litigation with respect to this agreement.

In September 2007, AE received an NOV from the EPA alleging NSR and PSD violations under the CAA, as well as Pennsylvania and West Virginia state laws at the coal-fired Hatfield's Ferry and Armstrong plants in Pennsylvania and the coal-fired Fort Martin and Willow Island plants in West Virginia. The EPA's NOV alleges equipment replacements during maintenance outages triggered the pre-construction permitting requirements under the NSR and PSD programs. On June 29, 2012, January 31, 2013, and March 27, 2013, EPA issued CAA section 114 requests for the Harrison coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2007. On December 12, 2014, EPA issued a CAA section 114 request for the Fort Martin coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2009. FirstEnergy intends to comply with the CAA but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

Climate Change

There are a number of initiatives to reduce GHG emissions at the state, federal and international level. Certain northeastern states are participating in the RGGI and western states led by California, have implemented programs, primarily cap and trade mechanisms, to control emissions of certain GHGs. Additional policies reducing GHG emissions, such as demand reduction programs, renewable portfolio standards and renewable subsidies have been implemented across the nation. A June 2013, Presidential Climate Action Plan outlined goals to: (i) cut carbon pollution in America by 17% by 2020 (from 2005 levels); (ii) prepare the United States for the impacts of climate change; and (iii) 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.

The EPA released its final "Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act" in December 2009, concluding that concentrations of several key GHGs constitutes an "endangerment" and may be regulated as "air pollutants" under the CAA and mandated measurement and reporting of GHG emissions from certain sources, including electric generating plants. The EPA released its final regulations in August 2015, to reduce CO_2 emissions from existing fossil fuel fired electric generating units that would require each state to develop SIPs by September 6, 2016, to meet the EPA's state specific CO_2 emission rate goals. The EPA's CPP allows states to request a 2-year extension to finalize SIPs by September 6, 2018. If states fail to develop SIPs, the EPA also proposed a federal implementation plan that can be implemented by the EPA that included model emissions trading rules which states can also adopt in their SIPs. The EPA also finalized separate regulations imposing CO_2 emission limits for new, modified, and reconstructed fossil fuel fired electric generating units. On June 23, 2014, the United States Supreme Court decided that CO_2 or other GHG emissions alone cannot trigger permitting requirements under the CAA, but that air emission sources that need PSD permits due to other regulated air pollutants can be required by the EPA to install GHG control technologies. On June 9, 2015, the U.S. Court of Appeals for the D.C. Circuit denied challenges to prevent the EPA from regulating CO_2 emissions from existing fossil fuel fired electric generating units because the EPA's proposed Clean Power Plant is not final agency action and therefore not ripe for review. Depending on the outcome of further appeals and how any final rules are ultimately implemented, the future cost of compliance may be substantial.

At the international level, the United Nations Framework Convention on Climate Change resulted in the Kyoto Protocol requiring participating countries, which does not include the U.S., to reduce GHGs commencing in 2008 and has been extended through 2020. In advance of the December 2015 United Nations Framework Convention on Climate Change meetings in Paris, the Obama Administration submitted in March 2015, a formal pledge for the U.S. to reduce its economy-wide greenhouse gas emissions by 26 to 28 percent below 2005 levels by 2025. FirstEnergy cannot currently estimate the financial impact of climate change policies, although potential legislative or regulatory programs restricting CO_2 emissions, or litigation alleging damages from GHG emissions, could require significant capital and other expenditures or result in changes to its operations. The CO_2 emissions per KWH of electricity generated by FirstEnergy is lower than many of its regional competitors due to its diversified generation sources, which include low or non-CO_2 emitting gas-fired and nuclear generators.

Clean Water Act

Various water quality regulations, the majority of which are the result of the federal CWA and its amendments, apply to FirstEnergy's plants. In addition, the states in which FirstEnergy operates have water quality standards applicable to FirstEnergy's operations.

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

The EPA proposed updates to the waste water effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423) in April 2013. On September 30, 2015, the EPA finalized new, more stringent effluent limits for arsenic, mercury, selenium and nitrogen for wastewater from wet scrubber systems and zero discharge of pollutants in ash transport water. The treatment obligations will phase-in as permits are renewed on a five-year cycle from 2018 to 2023. The final rule also allows plants to commit to more stringent effluent limits for wet scrubber systems based on evaporative technology and in return have until the end of 2023 to meet the more stringent limits. Depending on the outcome of appeals and how any final rules are ultimately implemented, the future costs of compliance with these standards may be substantial and changes to FirstEnergy's and FES' operations may result.

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 the appeal or estimate the possible loss or range of loss.

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

Regulation of Waste Disposal

Federal and state hazardous waste regulations have been promulgated as a result of the RCRA, as amended, and the Toxic Substances Control Act. Certain coal combustion residuals, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation.

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

The PA DEP filed a 2012 complaint against FG in the United States District Court for the Western District of Pennsylvania with claims under the RCRA and Pennsylvania's Solid Waste Management Act regarding the LBR CCR Impoundment and simultaneously proposed a consent decree between PA DEP and FG to resolve those claims. On December 14, 2012, a modified consent decree was entered by the court, requiring FG to conduct monitoring studies and submit a closure plan to the PA DEP, no later than March 31, 2013, and discontinue disposal to LBR as currently permitted by December 31, 2016. The modified consent decree also required payment of civil penalties of $800,000 to resolve claims under the Solid Waste Management Act. PA DEP issued a 2014 permit requiring FE to provide bonding for 45 years of closure and post-closure activities and to complete closure within a 12-year period, but authorizing FE to seek a permit modification based on "unexpected site conditions that have or will slow closure progress." The permit does not require active dewatering of the CCRs, but does require a groundwater assessment for arsenic and abatement if certain conditions in the permit are met. The Bruce Mansfield plant is pursuing several options for its CCRs following December 31, 2016. A June 28, 2013 complaint filed by Citizens Coal Counsel and other NGOs in the United States District Court for the Western District of Pennsylvania, against the owner and operator of a reclamation mine in LaBelle, Pennsylvania that is one possible alternative, alleged the LaBelle site is in violation of RCRA and state laws. On July 14, 2014, Citizens Coal Council served FE, FG and NRG with a citizen suit notice alleging violations of RCRA due to beneficial reuse of "coal ash" at the LaBelle Site. To date, no complaint has been filed. On May 22, 2015 and September 21, 2015, the PA DEP reissued a permit for the Hatfield's Ferry CCR disposal facility and then modified that permit to allow disposal of Bruce Mansfield plant CCR. On July 6, 2015 and October 22, 2015, the Sierra Club filed Notice of Appeals with the Pennsylvania Environmental Hearing Board challenging the renewal, reissuance and modification of the permit for the Hatfield’s Ferry CCB disposal facility.

FirstEnergy or its subsidiaries have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the CERCLA. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all potentially responsible parties for a particular site may be liable on a joint and several basis. Environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheets as of September 30, 2015 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 $148 million have been accrued through September 30, 2015. Included in the total are accrued liabilities of approximately $93 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, 2015, FirstEnergy had approximately $2.3 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. The values of FirstEnergy's NDTs fluctuate based on market conditions. If the value of the trusts decline by a material amount, FirstEnergy's obligation to fund the trusts may increase. Disruptions in the capital markets and their effects on particular businesses and the economy could also affect the values of the NDTs. FE and FES have also entered into a total of $24.5 million in parental guaranties in support of the decommissioning of the spent fuel storage facilities located at the nuclear facilities. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guaranties, as appropriate.

In August 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse operating license for an additional twenty years, until 2037. An NRC ASLB granted an opportunity for a hearing on the Davis-Besse license renewal application to a group of Intervenors, subject to the admissibility of contentions. On March 10, 2015, the ASLB issued an Order that terminated its jurisdiction and closed the record in the Davis-Besse license renewal proceeding. On June 9, 2015, the NRC Commissioners denied an intervenor's filed requests to reopen the record and admit a contention on the NRC’s Continued Storage Rule. On August 6, 2015, this intervenor sought review of the NRC Commissioners' decision before the U.S. Court of Appeals for the DC Circuit. FENOC has moved to intervene in that proceeding.

As part of routine inspections of the concrete shield building at Davis-Besse in 2013, FENOC identified changes to the subsurface laminar cracking condition originally discovered in 2011. These inspections revealed that the cracking condition had propagated a small amount in select areas. FENOC's analysis confirms that the building continues to maintain its structural integrity, and its ability to safely perform all of its functions. In a May 28, 2015, Inspection Report regarding the apparent cause evaluation on crack propagation, the NRC issued a non-cited violation for FENOC’s failure to request and obtain a license amendment for its method of evaluating the significance of the shield building cracking. The NRC also concluded that the shield building remained capable of performing its design safety functions despite the identified laminar cracking and that this issue was of very low safety significance.

The NRC continues to evaluate FENOC's analysis of the shield building.

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

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 Operations and Comprehensive Income (Loss) for the three and nine months ended September 30, 2015 and 2014, Condensed Consolidating Balance Sheets as of September 30, 2015 and December 31, 2014, and Condensed Consolidating Statements of Cash Flows for the nine months ended September 30, 2015 and 2014, 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 OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

For the Three Months Ended September 30, 2015	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME					
REVENUES	$1,293	$420	$531	$(906)	$1,338
OPERATING EXPENSES:					
Fuel	—	193	52	—	245
Purchased power from affiliates	932	—	77	(906)	103
Purchased power from non-affiliates	401	—	—	—	401
Other operating expenses	34	66	134	12	246
Provision for depreciation	3	30	47	(1)	79
General taxes	10	8	6	—	24
Total operating expenses	1,380	297	316	(895)	1,098
OPERATING INCOME (LOSS)	(87)	123	215	(11)	240
OTHER INCOME (EXPENSE):					
Loss on debt redemptions	—	—	—	—	—
Investment income (loss), including net income from equity investees	191	4	(18)	(198)	(21)
Miscellaneous income	—	1	—	—	1
Interest expense — affiliates	(8)	(2)	(1)	9	(2)
Interest expense — other	(13)	(26)	(12)	15	(36)
Capitalized interest	—	1	7	—	8
Total other income (expense)	170	(22)	(24)	(174)	(50)
INCOME BEFORE INCOME TAXES (BENEFITS)	83	101	191	(185)	190
INCOME TAXES (BENEFITS)	(37)	36	70	1	70
NET INCOME	$120	$65	$121	$(186)	$120
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$120	$65	$121	$(186)	$120
OTHER COMPREHENSIVE LOSS:					
Pension and OPEB prior service costs	(4)	(3)	—	3	(4)
Amortized gain on derivative hedges	—	—	—	—	—
Change in unrealized gain on available-for-sale securities	(11)	—	(11)	11	(11)

Other comprehensive loss	(15)	(3)	(11)	14	(15)
Income tax benefits on other comprehensive loss	(6)	(1)	(4)	5	(6)
Other comprehensive loss, net of tax	(9)	(2)	(7)	9	(9)
COMPREHENSIVE INCOME	$111	$63	$114	$(177)	$111

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

For the Nine Months Ended September 30, 2015	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME					
REVENUES	$3,699	$1,259	$1,494	$(2,618)	$3,834
OPERATING EXPENSES:					
Fuel	—	523	143	—	666
Purchased power from affiliates	2,657	—	211	(2,618)	250
Purchased power from non-affiliates	1,336	—	—	—	1,336
Other operating expenses	316	208	452	36	1,012
Provision for depreciation	8	92	142	(2)	240
General taxes	36	23	19	—	78
Total operating expenses	4,353	846	967	(2,584)	3,582
OPERATING INCOME (LOSS)	(654)	413	527	(34)	252
OTHER INCOME (EXPENSE):					
Loss on debt redemptions	—	—	—	—	—
Investment income (loss), including net income from equity investees	551	12	(1)	(569)	(7)
Miscellaneous income	1	4	—	—	5
Interest expense — affiliates	(21)	(6)	(3)	24	(6)
Interest expense — other	(39)	(78)	(37)	44	(110)
Capitalized interest	—	4	22	—	26
Total other income (expense)	492	(64)	(19)	(501)	(92)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES (BENEFITS)	(162)	349	508	(535)	160
INCOME TAXES (BENEFITS)	(258)	131	187	4	64
INCOME FROM CONTINUING OPERATIONS	96	218	321	(539)	96
Discontinued operations (Note 14)	—	—	—	—	—
NET INCOME	$96	$218	$321	$(539)	$96
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$96	$218	$321	$(539)	$96

OTHER COMPREHENSIVE LOSS:					
Pensions and OPEB prior service costs	(12)	(11)	—	11	(12)
Amortized gain on derivative hedges	(2)	—	—	—	(2)
Change in unrealized gain on available-for-sale securities	(20)	—	(20)	20	(20)
Other comprehensive loss	(34)	(11)	(20)	31	(34)
Income tax benefits on other comprehensive loss	(13)	(4)	(7)	11	(13)
Other comprehensive loss, net of tax	(21)	(7)	(13)	20	(21)
COMPREHENSIVE INCOME	$75	$211	$308	$(519)	$75

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

For the Three Months Ended September 30, 2014	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME					
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 redemption	—	—	(1)	—	(1)
Investment income, including net income from equity investees	2	3	13	(5)	13
Miscellaneous income (expense)	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) BEFORE INCOME TAXES (BENEFITS)	(94)	140	312	(286)	72
INCOME TAXES (BENEFITS)	(138)	49	117	—	28
NET INCOME	$44	$91	$195	$(286)	$44
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$44	$91	$195	$(286)	$44
OTHER COMPREHENSIVE LOSS:					
Pension 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 OPERATIONS 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, including net income from equity investees	5	6	57	(11)	57
Miscellaneous income	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)

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FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

As of September 30, 2015	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$—	$2	$—	$—	$2
Receivables-					
Customers	303	—	—	—	303
Affiliated companies	376	331	366	(563)	510
Other	36	3	39	—	78
Notes receivable from affiliated companies	384	1,140	747	(2,271)	—
Materials and supplies	43	182	221	—	446
Derivatives	147	—	—	—	147
Collateral	122	—	—	—	122
Prepayments and other	66	78	2	(8)	138
	1,477	1,736	1,375	(2,842)	1,746
PROPERTY, PLANT AND EQUIPMENT:					
In service	90	6,339	7,956	(382)	14,003
Less — Accumulated provision for depreciation	37	2,116	3,559	(193)	5,519
	53	4,223	4,397	(189)	8,484
Construction work in progress	4	189	732	—	925
	57	4,412	5,129	(189)	9,409
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,323	—	1,323
Investment in affiliated companies	7,147	—	—	(7,147)	—
Other	—	10	—	—	10
	7,147	10	1,323	(7,147)	1,333
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	324	—	—	(324)	—
Customer intangibles	65	—	—	—	65
Goodwill	23	—	—	—	23
Property taxes	—	4	6	—	10
Unamortized sale and leaseback costs	—	—	—	260	260
Derivatives	118	—	—	—	118
Other	41	326	21	(265)	123
	571	330	27	(329)	599
	$9,252	$6,488	$7,854	$(10,507)	$13,087
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$—	$230	$331	$(24)	$537
Short-term borrowings-					
Affiliated companies	1,914	373	1	(2,271)	17
Other	—	8	—	—	8
Accounts payable-					

Affiliated companies	634	145	152	(634)	297
Other	26	105	—	—	131
Accrued taxes	1	29	54	—	84
Derivatives	121	—	—	—	121
Other	48	71	16	26	161
	2,744	961	554	(2,903)	1,356
CAPITALIZATION:					
Total equity	5,675	2,780	4,328	(7,108)	5,675
Long-term debt and other long-term obligations	695	2,134	850	(1,149)	2,530
	6,370	4,914	5,178	(8,257)	8,205
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	799	799
Accumulated deferred income taxes	12	80	726	(146)	672
Retirement benefits	36	298	—	—	334
Asset retirement obligations	—	191	670	—	861
Derivatives	58	2	—	—	60
Other	32	42	726	—	800
	138	613	2,122	653	3,526
	$9,252	$6,488	$7,854	$(10,507)	$13,087

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

As of December 31, 2014	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$—	$2	$—	$—	$2
Receivables-					
Customers	415	—	—	—	415
Affiliated companies	484	487	674	(1,120)	525
Other	66	21	20	—	107
Notes receivable from affiliated companies	339	838	272	(1,449)	—
Materials and supplies	67	202	223	—	492
Derivatives	147	—	—	—	147
Collateral	229	—	—	—	229
Prepayments and other	56	41	—	(2)	95
	1,803	1,591	1,189	(2,571)	2,012
PROPERTY, PLANT AND EQUIPMENT:					
In service	133	6,217	7,628	(382)	13,596
Less — Accumulated provision for depreciation	36	2,058	3,305	(191)	5,208
	97	4,159	4,323	(191)	8,388
Construction work in progress	3	206	801	—	1,010
	100	4,365	5,124	(191)	9,398
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,365	—	1,365
Investment in affiliated companies	6,607	—	—	(6,607)	—
Other	—	10	—	—	10
	6,607	10	1,365	(6,607)	1,375
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	276	76	—	(352)	—
Customer intangibles	78	—	—	—	78
Goodwill	23	—	—	—	23
Property taxes	—	14	27	—	41
Unamortized sale and leaseback costs	—	—	—	217	217
Derivatives	52	—	—	—	52
Other	34	277	7	(204)	114
	463	367	34	(339)	525
	$8,973	$6,333	$7,712	$(9,708)	$13,310
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$18	$164	$348	$(24)	$506
Short-term borrowings-					
Affiliated companies	1,135	321	28	(1,449)	35
Other	90	9	—	—	99

Accounts payable-					
Affiliated companies	1,068	197	219	(1,068)	416
Other	46	202	—	—	248
Accrued taxes	2	62	161	(123)	102
Derivatives	166	—	—	—	166
Other	72	56	9	47	184
	2,597	1,011	765	(2,617)	1,756
CAPITALIZATION:					
Total equity	5,585	2,561	4,014	(6,575)	5,585
Long-term debt and other long-term obligations	695	2,215	859	(1,161)	2,608
	6,280	4,776	4,873	(7,736)	8,193
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	824	824
Accumulated deferred income taxes	13	—	678	(180)	511
Retirement benefits	36	288	—	—	324
Asset retirement obligations	—	189	652	—	841
Derivatives	14	—	—	—	14
Other	33	69	744	1	847
	96	546	2,074	645	3,361
	$8,973	$6,333	$7,712	$(9,708)	$13,310

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

For the Nine Months Ended September 30, 2015	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$(624)	$405	$867	$(12)	$636
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	—	43	296	—	339
Short-term borrowings, net	689	51	—	(740)	—
Redemptions and Repayments-					
Long-term debt	(17)	(55)	(322)	12	(382)
Short-term borrowings, net	—	—	(27)	(82)	(109)
Other	—	(4)	(1)	—	(5)
Net cash provided from (used for) financing activities	672	35	(54)	(810)	(157)
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(3)	(144)	(194)	—	(341)
Nuclear fuel	—	—	(101)	—	(101)
Proceeds from asset sales	10	3	—	—	13
Sales of investment securities held in trusts	—	—	503	—	503
Purchases of investment securities held in trusts	—	—	(546)	—	(546)
Cash investments	(10)	—	—	—	(10)
Loans to affiliated companies, net	(45)	(302)	(475)	822	—
Other	—	3	—	—	3
Net cash used for investing activities	(48)	(440)	(813)	822	(479)
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, 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

13. SEGMENT INFORMATION

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

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 located primarily in West Virginia, Virginia and New Jersey that MP and JCP&L, respectively, own or contractually control. The segment's results reflect the commodity costs of securing electric generation and the deferral and amortization of certain fuel costs. This business segment currently controls 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 primarily from transmission services provided pursuant to the PJM Tariff to LSEs. The segment's results also reflect the net transmission expenses related to the delivery of electricity on FirstEnergy's transmission facilities.

The CES segment, through FES and AE Supply, primarily supplies electricity to end-use customers through retail and wholesale arrangements, including competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, and the provision of partial POLR and default service for some utilities in Ohio, Pennsylvania and Maryland, including the Utilities. This business segment currently controls 13,162 MWs of capacity. The CES 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 and capacity costs charged by PJM to deliver energy to the segment’s customers. In 2014, the CES segment began reducing its exposure to weather-sensitive loads, 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.

Corporate support and other businesses that are below the quantifiable threshold for separate disclosure as a reportable segment, interest expense on stand-alone holding company debt and corporate income taxes are categorized as Corporate/Other for reportable business segment purposes. As of September 30, 2015, Corporate/Other had $4.2 billion of stand-alone holding company long-term debt, of which 28% was subject to variable-interest rates, and $1.9 billion was borrowed by FE under its revolving credit facility. Reconciling adjustments for the elimination of inter-segment transactions are shown separately in the accompanying table.

Segment Financial Information

Three Months Ended	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/ Other	Reconciling Adjustments	Consolidated
	(In millions)					
September 30, 2015						
External revenues	$2,624	$ 248	$1,327	$(42)	$(34)	$4,123
Internal revenues	—	—	141	—	(141)	—
Total revenues	2,624	248	1,468	(42)	(175)	4,123
Depreciation	174	41	98	15	—	328
Amortization of regulatory assets, net	110	—	—	—	—	110
Investment income (loss)	8	—	(27)	2	(11)	(28)
Interest expense	149	40	48	48	—	285
Income taxes (benefits)	137	41	81	(36)	3	226
Net income (loss)	234	70	140	(49)	—	395
Total assets	28,224	7,183	16,486	770	—	52,663
Total goodwill	5,092	526	800	—	—	6,418
Property additions	292	149	83	15	—	539
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	165	33	100	11	(1)	308
Amortization of regulatory assets, net	33	3	—	—	(1)	35
Investment income (loss)	14	—	11	4	(13)	16
Interest expense	147	35	49	46	(2)	275
Income taxes (benefits)	124	30	36	(42)	4	152
Net income (loss)	227	55	66	(15)	—	333
Total assets	27,774	6,102	16,839	509	—	51,224
Total goodwill	5,092	526	800	—	—	6,418
Property additions	271	279	97	17	—	664
Nine Months Ended						
September 30, 2015						
External revenues	$7,425	$ 755	$3,536	$(126)	$(105)	$11,485
Internal revenues	—	—	563	—	(563)	—
Total revenues	7,425	755	4,099	(126)	(668)	11,485
Depreciation	516	116	293	44	—	969
Amortization of regulatory assets, net	196	5	—	—	—	201
Investment income (loss)	33	—	(23)	7	(31)	(14)
Interest expense	439	119	144	144	—	846
Income taxes (benefits)	350	135	70	(78)	8	485

Income (loss) from continuing operations	598	231	119	(144)	—	804
Net income (loss)	598	231	119	(144)	—	804
Property additions	884	700	400	41	—	2,025
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	491	93	287	34	(1)	904
Amortization of regulatory assets, net	18	9	—	—	—	27
Investment income (loss)	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
Property additions	780	980	655	58	—	2,473

14. DISCONTINUED OPERATIONS

On February 12, 2014, certain of FirstEnergy's subsidiaries sold eleven hydroelectric power stations to a subsidiary of LS Power 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). Pre-tax income for the hydroelectric facilities of $155 million (FES - $186 million) for the nine months ended September 30, 2014, was included in discontinued operations in the Consolidated Statement of Income. 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, were included in discontinued operations in the Consolidated Statement of Income.

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
FIRSTENERGY'S BUSINESS

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

The Regulated Distribution segment distributes electricity through FirstEnergy's ten utility operating companies, serving approximately six million customers within 65,000 square miles of Ohio, Pennsylvania, West Virginia, Maryland, New Jersey and New York, and purchases power for its POLR, SOS, SSO and default service requirements in Ohio, Pennsylvania, New Jersey and Maryland. This segment also includes regulated electric generation facilities located primarily in West Virginia, Virginia and New Jersey that MP and JCP&L, respectively, own or contractually control. The segment's results reflect the commodity costs of securing electric generation and the deferral and amortization of certain fuel costs. This business segment currently controls 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 primarily from transmission services provided pursuant to the PJM Tariff to LSEs. The segment's results also reflect the net transmission expenses related to the delivery of electricity on FirstEnergy's transmission facilities.

The CES segment, through FES and AE Supply, primarily supplies electricity to end-use customers through retail and wholesale arrangements, including competitive retail sales to customers primarily in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland, and the provision of partial POLR and default service for some utilities in Ohio, Pennsylvania and Maryland, including the Utilities. This business segment currently controls 13,162 MWs of capacity.

The CES 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 and capacity costs charged by PJM to deliver energy to the segment's customers.

The segment derives its revenues from the sale of generation to direct, governmental aggregation, POLR, structured and wholesale customers. The segment is exposed to various market and financial risks, including the risk of price fluctuations in the wholesale power markets. Wholesale power prices may be impacted by the prices of other commodities, including coal and natural gas, and energy efficiency and DR programs, as well as regulatory and legislative actions, such as MATS, among other factors. The segment attempts to mitigate the market risk inherent in its energy position by economically hedging its exposure and continuously monitoring various risk measurement metrics to ensure compliance with its risk management policies. In 2014, the CES segment began reducing its exposure to weather-sensitive loads, 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.

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.

Corporate support and other businesses that are below the quantifiable threshold for separate disclosure as a reportable segment, interest expense on stand-alone holding company debt and corporate income taxes are categorized as Corporate/Other for reportable business segment purposes. Additionally, reconciling adjustments for the elimination of inter-segment transactions are included in Corporate/Other. As of September 30, 2015, Corporate/Other had $4.2 billion of stand-alone holding company long-term debt, of which 28% was subject to variable-interest rates, and $1.9 billion was borrowed by FE under its revolving credit facility.

EXECUTIVE SUMMARY

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

Focusing on reinvestment in its regulated operations will also provide stability and growth for FirstEnergy as this plan is implemented over the coming years. The centerpiece of FirstEnergy’s regulated investment strategy is the Energizing the Future transmission expansion plan, which was introduced in late 2013. The initial phase of this plan includes $4.2 billion in investments from 2014 through 2017 to modernize the transmission system owned by FirstEnergy’s Regulated Transmission segment. In 2014, Regulated Transmission's capital expenditures were $1.4 billion and the segment expects 2015 capital expenditures of $970 million for regulatory required and reliability enhancement projects. FirstEnergy expects to fund these investments through a combination of cash from operations, debt, and, depending on the regulated operating company, capital contributions from its parent. In the future, FirstEnergy may consider equity issuances to fund capital investments in the regulated operations.

The transmission investment program is also designed to prepare the electrical system for load growth, including increased demand related to continued development in the Marcellus and Utica shale regions of the utilities’ western Pennsylvania, eastern Ohio and West Virginia service areas. While FirstEnergy continues to monitor recent developments in shale related activity, in 2014, more than 400 MWs of new industrial demand associated with shale gas activity came online in FirstEnergy’s region, and more than 1,000 MWs of additional planned expansion is expected at customer facilities through 2019.

As part of an effort to manage costs, FirstEnergy identified both immediate and long-term savings opportunities through its cash flow improvement plan. The cash flow improvement plan identified targeted cash savings of approximately $58 million in 2015, $155 million in 2016 and $240 million annually by 2017, with reductions in operating expenses representing approximately 65% of the savings over the three year period.

During the third quarter of 2015, FirstEnergy continued to pursue key regulatory initiatives across its utility footprint, focusing on providing significant benefits to customers while ensuring the timely and appropriate recovery of investments. These initiatives include:

- The Ohio Companies' ESP IV, Powering Ohio’s Progress: Evidentiary hearings commenced in August 2015 and in September 2015 PUCO Staff filed testimony addressing various matters within the ESP IV filing. A final decision is anticipated in early 2016. The ESP IV would freeze base distribution rates through May 2019 while helping ensure continued availability of more than 3,200 MWs of FirstEnergy’s critical baseload generating assets primarily located in the state and serving the long-term energy needs of Ohio customers.
- ATSI's Formula Rate Filing: In October 2014, ATSI filed a proposal with FERC to change the structure of its formula rate to a "forward looking" approach, where transmission rates would be based on estimated costs for the current year with an annual true up. In late 2014, FERC issued an order accepting ATSI's rate filing to become effective January 1, 2015, as requested, subject to refund and the outcome of hearing and settlement proceedings and FERC's inquiry into ATSI's ROE. In July 2015, ATSI and certain parties filed a settlement agreement with FERC, which remains subject to FERC's approval. The agreement provides for certain changes to ATSI's proposed forward-looking formula rate template and protocols, and also changes ATSI's ROE from 12.38% to the following values: (i) 12.38% for the period commencing January 1, 2015 through June 30, 2015; (ii) 11.06% for the period commencing July 1, 2015 through December 31, 2015; and (iii) 10.38% for the period commencing January 1, 2016. The 10.38% ROE value will remain in effect unless changed pursuant to section 205 or 206 of the FPA provided the effective date for any change cannot be earlier than January 1, 2018. The agreement currently is pending at FERC and ATSI anticipates that it will be approved later this year.
- Transfer of JCP&L, PN and ME Transmission Assets to MAIT: In June 2015, JCP&L, PN, ME, FET, and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT. If approved, MAIT will operate similar to FET’s two existing stand-alone transmission subsidiaries ATSI and TrAIL. MAIT's transmission facilities will remain under the functional control of PJM, and PJM will provide transmission service using these facilities under the PJM Tariff. During the third quarter of 2015, FirstEnergy responded to FERC Staff’s request for additional information regarding the application. FERC approval is expected in early-2016 with final decisions expected from the NJBPU and PPUC by mid-2016. Following FERC approval of the transfer, MAIT expects to file a Section 204 application with FERC, and other necessary filings with the PPUC and the NJBPU, seeking authorization to issue equity to FET, JCP&L, PN and ME for their respective asset contributions, and to issue debt. MAIT will also make a Section 205 formula rate application with FERC to

establish its transmission rate.

In 2014, FirstEnergy set a new course for CES designed to limit risk in the current difficult energy market, while positioning the business to take advantage of future market upside. In 2015, FirstEnergy continues to reposition its competitive business to focus on reducing exposure to weather-sensitive load in certain sales channels and pursuing high-margin sales, while also leaving a portion of its generation available to capture future market opportunities. This strategy is designed to better position CES to benefit from opportunities as markets improve while limiting risk from continued challenging market conditions. At the same time, FirstEnergy continues to advocate for reforms that can ensure competitive wholesale markets adequately value baseload generation, which is essential to maintaining grid reliability.

The CES segment economically hedges exposure to price risk on a ratable basis, which is intended to reduce the near-term financial impact of market price volatility. On average, the CES segment expects to produce approximately 75 - 80 million MWHs of electricity annually, with up to an additional 5 million MWHs available from purchased power agreements for wind, solar and its entitlement from OVEC. The CES 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, as necessary, purchasing power in the wholesale market. As of September 30, 2015, committed sales for 2015 are approximately 72 million MWHs. For the fourth quarter of 2015, supply from expected generation and committed purchases is approximately 116% of committed sales (assuming normal weather conditions). As of September 30, 2015, committed sales for 2016 and 2017 are approximately 59 million MWHs and 36 million MWHs, respectively.

FirstEnergy has also reduced the size and shifted the mix of its generating assets, while reducing operating expenses and capital expenditures, including the deactivation of certain plants and the 2014 sale of certain hydroelectric facilities. As a result, the remaining competitive fleet is more cost-effective, efficient and environmentally sound. FirstEnergy is on track to exceed benchmarks established by MATS and other environmental regulations. FirstEnergy's total cost for MATS compliance is expected to be approximately $370 million ($178 million at CES and $192 million at Regulated Distribution), of which $176 million has been spent through September 30, 2015 ($66 million at CES and $110 million at Regulated Distribution).

During the third quarter of 2015, PJM conducted the 2015 BRA for the 2018/2019 delivery year and Capacity Performance transition auctions for the 2016/2017 and 2017/2018 delivery years. FirstEnergy's net competitive capacity position as a result of the BRA and Capacity Performance transition auctions is as follows:

	2016 - 2017				2017 - 2018				2018 - 2019*			
	Legacy Obligation		Capacity Performance		Legacy Obligation		Capacity Performance		Base Generation		Capacity Performance	
	(MW)	($/MWD)	(MW)	($/MWD)	(MW)	($/MWD)	(MW)	($/MWD)	(MW)	($/MWD)	(MW)	($/MWD)
ATSI	2,765	$114.23	4,210	$134.00	375	$120.00	6,245	$151.50	—	$149.98	6,245	$164.77
RTO	875	$59.37	3,675	$134.00	985	$120.00	3,565	$151.50	240	$149.98	3,930	$164.77
All Other Zones	135	$119.13	—	$134.00	150	$120.00	—	$151.50	35	**	20	**
	3,775		7,885		1,510		9,810		275		10,195	

*Approximately 885 MWs remain uncommitted for the 2018/2019 delivery year.
**Base Generation: 10 MWs cleared at $200.21/MWD and 25 MWs cleared at $149.98/MWD. Capacity Performance: 5 MWs cleared at $215.00/MWD and 15 MWs cleared at $164.77/MWD.

Projected CES Capacity Revenue ($ Millions)

	2016	2017	2018	2019 (through 5/31)
Capacity Revenue	$815	$590	$620	$260

Operational Matters

On September 26, 2015, the 933-MW Beaver Valley Unit 2 began a scheduled refueling and maintenance outage. While the unit is offline, one third of the 157 fuel assemblies will be replaced and numerous safety inspections will be conducted. In addition, preventative maintenance to ensure continued safe and reliable operations will be performed on major components, including the plant's three steam generators, as well as various pumps, valves and the cooling tower.

As previously disclosed, FirstEnergy is moving forward with the planned water treatment upgrades at the Bruce Mansfield plant, which are necessary to allow the plant to continue to operate after December 31, 2016, when the LBR CCR impoundment is required to close. Estimated 2015 capital expenditures for the water treatment upgrades are approximately $117 million and are included in FirstEnergy's 2015 capital expenditures forecast of $2.9 billion.

Financial Overview (In millions, except per share amounts)	Three Months Ended September 30, 2015	2014	Change		Nine Months Ended September 30, 2015	2014	Change	
REVENUES:	$4,123	$3,888	$235	6 %	$11,485	$11,566	$(81)	(1)%
OPERATING EXPENSES:								
Fuel	482	544	(62)	(11)%	1,378	1,711	(333)	(19)%
Purchased power	1,209	1,188	21	2 %	3,311	3,726	(415)	(11)%
Other operating expenses	850	858	(8)	(1)%	2,823	3,061	(238)	(8)%
Provision for depreciation	328	308	20	6 %	969	904	65	7 %
Amortization of regulatory assets, net	110	35	75	214 %	201	27	174	644 %
General taxes	236	239	(3)	(1)%	747	738	9	1 %
Total operating expenses	3,215	3,172	43	1 %	9,429	10,167	(738)	(7)%
OPERATING INCOME	908	716	192	27 %	2,056	1,399	657	47 %
OTHER INCOME (EXPENSE):								
Loss on debt redemptions	—	—	—	— %	—	(8)	8	100 %
Investment income (loss)	(28)	16	(44)	(275)%	(14)	67	(81)	(121)%
Interest expense	(285)	(275)	(10)	(4)%	(846)	(802)	(44)	(5)%
Capitalized financing costs	26	28	(2)	(7)%	93	89	4	4 %
Total other expense	(287)	(231)	(56)	(24)%	(767)	(654)	(113)	(17)%
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	621	485	136	28 %	1,289	745	544	73 %
INCOME TAXES	226	152	74	49 %	485	226	259	115 %
INCOME FROM CONTINUING OPERATIONS	395	333	62	19 %	804	519	285	55 %
Discontinued operations (net of income taxes of $69) (Note 14)	—	—	—	— %	—	86	(86)	(100)%
NET INCOME	$395	$333	$62	19 %	$804	$605	$199	33 %
EARNINGS PER SHARE OF COMMON STOCK:								
Basic - Continuing Operations	$0.94	$0.79	$0.15	19 %	$1.91	$1.24	$0.67	54 %
Basic - Discontinued Operations (Note 14)	—	—	—	— %	—	0.20	(0.20)	(100)%
Basic - Net Earnings per Basic Share	$0.94	$0.79	$0.15	19 %	$1.91	$1.44	$0.47	33 %
Diluted - Continuing Operations	$0.93	$0.79	$0.14	18 %	$1.90	$1.24	$0.66	53 %
	—	—	—	— %	—	0.20	(0.20)	(100)%

Diluted - Discontinued Operations (Note 14)									
Diluted - Net Earnings per Diluted Share	$0.93	$0.79	$0.14	18	%	$1.90	$1.44	$0.46	32 %

Three Months Ended September 30, 2015

For the three months ended September 30, 2015, FirstEnergy's net income was $395 million, or basic earnings of $0.94 per share ($0.93 diluted), compared to $333 million, or $0.79 per share (basic and diluted) for the three months ended September 30, 2014.

As further discussed below, the increase in FirstEnergy's third quarter earnings primarily resulted from a year-over-year earnings improvement of $74 million at CES, $15 million at Regulated Transmission and $7 million at Regulated Distribution, partially offset by a $34 million decrease at Corporate/Other. CES earnings in the third quarter of 2015 benefited from higher capacity prices and lower operating expenses as the segment continues to execute its revised sales strategy, while Regulated Transmission earnings benefited from ATSI's forward looking rate and an increase in cost of service and rate base recovery. During the third quarter of 2015, Corporate/Other was impacted primarily by lower income tax benefits and higher environmental remediation costs associated with legacy manufactured gas plants and gas holder facilities.

For the third quarter of 2015, FirstEnergy revenues increased $235 million, or 6%, compared to the third quarter of 2014. The increase resulted from a $267 million increase at Regulated Distribution and a $51 million increase at Regulated Transmission, partially offset by a $131 million decrease at CES. The year-over-year increase in Regulated Distribution revenue resulted from a net rate increase associated with the implementation of new rates at certain operating companies as well as a year-over-year increase in retail generation and retail transmission revenues. Additionally, increased weather-related usage resulting from cooling degree days that were 36% above 2014 were partially offset by declining weather-adjusted average customer usage associated with energy efficiency mandates. The year-over-year increase at Regulated Transmission primarily resulted from ATSI's transition to a forward looking rate, effective January 1, 2015. The decrease in revenue at CES resulted from a decline in contract sales in line with CES' revised sales strategy discussed above. The decline in CES contract sales was mitigated by higher wholesale sales, including higher spot market energy sales, and increased capacity revenue associated with higher capacity prices.

For the third quarter of 2015, operating expenses increased $43 million, or 1%, compared to the third quarter of 2014. The increase in operating expenses primarily resulted from a $240 million increase at Regulated Distribution, which primarily resulted from an increase in purchased power associated with higher retail generation sales and higher unit costs from recent default service auctions, as well as increased amortization of regulatory assets, primarily associated with the recovery of deferred storm costs included in the new rates implemented in 2015 as discussed above. Additionally, Regulated Transmission operating expenses increased $15 million primarily related to an increase in property taxes and depreciation expense associated with a higher asset base. Partially offsetting this increase was a $284 million decrease at CES, mainly due to lower purchased power, transmission expenses and retail-related costs associated with lower contract sales as well as lower fuel expense.

Other expenses increased $56 million, or 24%, in the third quarter of 2015 as compared to the third quarter of 2014, resulting from lower investment income, including a $39 million increase in OTTI, and higher interest expense.

For the third quarter of 2015, FirstEnergy’s effective tax rate was 36.4%, compared with an effective tax rate of 31.3% for the three-months ended September 30, 2014. The increase in the effective tax rate was primarily due to tax benefits recorded in the third quarter of 2014 associated with an IRS-approved change in accounting method for costs associated with the refurbishment of meters and transformers.

Nine Months Ended September 30, 2015

For the nine months ended September 30, 2015, FirstEnergy’s net income was $804 million, or basic earnings of $1.91 per share ($1.90 diluted), compared to $605 million, or $1.44 per share (basic and diluted) for the nine months ended September 30, 2014.

The increase in earnings primarily resulted from a $210 million increase at CES and a $62 million increase at Regulated Transmission, partially offset by a $72 million decline at Corporate/Other. The improvement in earnings at CES resulted from higher capacity revenues and the absence of the impact of extreme market conditions and unplanned outages in 2014, which resulted in higher costs to serve contract sales. The improvement at Regulated Transmission primarily resulted from ATSI’s implementation of a forward looking rate, effective in January 2015, and an increase in cost of service and rate base recovery. The decline at Corporate/Other primarily resulted from higher interest expense, additional environmental remediation costs as discussed above, and lower income tax benefits.

For the nine months ended September 30, 2015, revenue decreased $81 million, or 1%, compared to the same period of 2014. The decline in revenue primarily resulted from a $764 million decrease at CES associated with a decline in contract sales volumes in line with CES’ revised sales strategy discussed above, partially offset by higher unit prices and higher capacity revenues. Partially offsetting the decrease at CES, Regulated Distribution's and Regulated Transmission’s revenue increased $453 million and $185 million, respectively. The year-over-year increase at Regulated Distribution primarily resulted from a net rate increase associated with the implementation of new rates discussed above, higher weather-related usage as well as a year-over-year increase in retail generation and retail transmission sales, partially offset by a decline in weather-adjusted average customer usage. The year-over-year increase in revenues at Regulated Transmission primarily resulted from ATSI’s transition to a forward looking rate as discussed above.

FirstEnergy operating expenses decreased $738 million, or 7%, in the first nine months of 2015 compared to the same period of 2014. The decline in operating expenses resulted from a $1,293 million decrease at CES, partially offset by a $434 million increase at Regulated Distribution and a $49 million increase at Regulated Transmission. The lower operating expenses at CES were primarily the result of lower purchased power, transmission expenses and retail-related costs associated with lower contract sales. Additionally, CES fuel expense decreased year-over-year primarily associated with lower fossil generation, and the absence of fuel contract termination costs recognized in 2014 as well as lower nuclear unit prices. The increase in operating expenses at Regulated Distribution was primarily due to higher net regulatory asset amortization associated with the recovery of deferred storm costs, higher purchased power costs associated with higher default service requirements, and higher operating and maintenance costs. The increase in operating expenses at Regulated Transmission primarily resulted from higher depreciation and property taxes associated with a higher asset base.

For the nine months ended September 30, 2015, FirstEnergy's other expense increased $113 million, or 17%, compared to 2014. The increase in other expense primarily resulted from lower investment income, including a $60 million increase in OTTI, and higher interest expense at Regulated Transmission and Corporate/Other.

For the nine months ended September 30, 2015 FirstEnergy’s effective tax rate was 37.6%, compared with an effective tax rate of 30.3% for the nine months ended September 30, 2014. The increase in the effective tax rate was primarily due to tax benefits recorded in 2014 associated with the change in accounting method discussed above. Additionally, in 2014, the effective tax rate was impacted by a reduction in state deferred tax liabilities resulting from changes in state apportionment factors and the elimination of certain future tax liabilities associated with basis differences.

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.

Summary of Results of Operations — Third Quarter 2015 Compared with Third Quarter 2014

Financial results for FirstEnergy's business segments in the third quarter of 2015 and 2014 were as follows:

Third Quarter 2015 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$2,571	$248	$1,276	$(41)	$4,054
Other	53	—	51	(35)	69
Internal	—	—	141	(141)	—
Total Revenues	2,624	248	1,468	(217)	4,123
Operating Expenses:					
Fuel	140	—	342	—	482
Purchased power	980	—	370	(141)	1,209
Other operating expenses	542	42	336	(70)	850
Provision for depreciation	174	41	98	15	328
Amortization of regulatory assets, net	110	—	—	—	110
General taxes	172	23	35	6	236
Total Operating Expenses	2,118	106	1,181	(190)	3,215
Operating Income	506	142	287	(27)	908
Other Income (Expense):					
Investment income (loss)	8	—	(27)	(9)	(28)
Interest expense	(149)	(40)	(48)	(48)	(285)
Capitalized financing costs	6	9	9	2	26
Total Other Expense	(135)	(31)	(66)	(55)	(287)
Income Before Income Taxes	371	111	221	(82)	621
Income taxes	137	41	81	(33)	226
Net Income	$234	$70	$140	$(49)	$395

Third Quarter 2014 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/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	479	106	134	(3)	716
Other Income (Expense):					
Investment income (loss)	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 Before Income Taxes	351	85	102	(53)	485
Income taxes	124	30	36	(38)	152
Net Income	$227	$55	$66	$(15)	$333

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Changes Between Third Quarter 2015 and Third Quarter 2014 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$267	$51	$(85)	$(3)	$230
Other	—	—	6	(1)	5
Internal	—	—	(52)	52	—
Total Revenues	267	51	(131)	48	235
Operating Expenses:					
Fuel	(19)	—	(43)	—	(62)
Purchased power	107	—	(138)	52	21
Other operating expenses	69	4	(96)	15	(8)
Provision for depreciation	9	8	(2)	5	20
Amortization of regulatory assets, net	77	(3)	—	1	75
General taxes	(3)	6	(5)	(1)	(3)
Total Operating Expenses	240	15	(284)	72	43
Operating Income	27	36	153	(24)	192
Other Income (Expense):					
Investment income (loss)	(6)	—	(38)	—	(44)
Interest expense	(2)	(5)	1	(4)	(10)
Capitalized financing costs	1	(5)	3	(1)	(2)
Total Other Expense	(7)	(10)	(34)	(5)	(56)
Income Before Income Taxes	20	26	119	(29)	136
Income taxes	13	11	45	5	74
Net Income	$7	$15	$74	$(34)	$62

Regulated Distribution — Third Quarter 2015 Compared with Third Quarter 2014

Regulated Distribution's net income increased $7 million in the third quarter of 2015 as compared to the same period of 2014, primarily reflecting higher distribution services revenues associated with higher weather-related usage and a net increase in new rates implemented at certain operating companies, partially offset by increased operating expenses and a higher effective tax rate.

Revenues —

The $267 million increase in total revenues resulted from the following sources:

Revenues by Type of Service	Three Months Ended September 30, 2015	2014	Increase (Decrease)
	(In millions)		
Distribution services	$1,096	$955	$141
Generation sales:			
Retail	1,182	1,068	114
Wholesale	131	165	(34)
Total generation sales	1,313	1,233	80
Transmission sales:			
Retail	137	89	48
Wholesale	25	27	(2)
Total transmission sales	162	116	46
Other	53	53	—
Total Revenues	$2,624	$2,357	$267

Distribution services revenues increased $141 million primarily resulting from approved base distribution rate increases in Pennsylvania, effective May 2015, and for MP and PE in West Virginia, effective February 2015, partially offset by a distribution rate decrease at JCP&L, including the recovery of 2011 and 2012 storm costs, effective April 2015. Additionally, distribution services revenues increased resulting from higher weather-related usage as described below and higher cost recovery for above-market NUG costs. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	Three Months Ended September 30, 2015	2014	Increase (Decrease)
	(In thousands)		
Residential	14,305	13,127	9.0 %
Commercial	11,463	11,169	2.6 %
Industrial	12,721	13,142	(3.2)%
Other	146	149	(2.0)%
Total Electric Distribution MWH Deliveries	38,635	37,587	2.8 %

Higher distribution deliveries to residential and commercial customers reflect increased weather-related usage resulting from cooling degree days that were 36% above 2014, and 13% above normal. The increase in residential deliveries was partially offset by declining average customer usage due, in part, to increasing energy efficiency mandates. Deliveries to industrial customers decreased 3.2%, primarily due to lower usage in steel, coal mining and electrical equipment and manufacturing sectors, partially offset by increased usage from shale gas and automotive sectors.

The following table summarizes the price and volume factors contributing to the $80 million increase in generation revenues for the third quarter of 2015 compared to the same period of 2014:

Source of Change in Generation Revenues	Increase (Decrease) (In millions)
Retail:	
Effect of increase in sales volumes	$82
Change in prices	32
	114
Wholesale:	
Effect of decrease in sales volumes	(33)
Change in prices	(8)
Capacity Revenue	7
	(34)
Increase in Generation Revenues	$80

The increase in retail generation sales volumes was primarily due to lower customer shopping in Pennsylvania and New Jersey and an increase in weather-related usage, as described above. Total generation provided by alternative suppliers as a percentage of total MWH deliveries decreased to 66% from 68% for the Pennsylvania Companies and to 47% from 49% for JCP&L. The increase in prices primarily resulted from higher default service auction results.

The decrease in wholesale generation revenues of $34 million reflects decreased volumes associated with the termination of a NUG contract at JCP&L in November of 2014 and lower economic dispatch associated with low spot market energy prices. Partially offsetting these decreases was an increase in capacity revenue resulting from higher capacity prices. The difference between current wholesale generation revenues and certain energy costs incurred are deferred for future recovery, with no material impact to earnings.

The increase in retail transmission revenues of $48 million was primarily due to an increase in the Ohio Companies' NMB transmission rider revenues. The NMB rider recovers network transmission integration service costs from all distribution customers at the Ohio Companies, with no material impact to earnings.

Operating Expenses —

Total operating expenses increased $240 million primarily due to the following:

- Fuel expense decreased $19 million in the third quarter of 2015, as compared to the same period in 2014, primarily related to lower generation resulting from lower economic dispatch due to low spot market energy prices.

- Purchased power costs were $107 million higher in the third quarter of 2015, as compared to the same period in 2014, primarily due to increased volumes reflecting lower customer shopping as discussed above and higher unit costs resulting from higher default service auction results.

Source of Change in Purchased Power	Increase(Decrease) (In millions)
Purchases from non-affiliates:	
Change due to increased unit costs	$ 41
Change due to increased volumes	106
	147
Purchases from affiliates:	
Change due to decreased unit costs	(8)

Change due to decreased volumes	(45)
	(53)
Capacity Expense	—
Amortization of deferred costs	13
Increase in Purchased Power Costs	$ 107

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- Other operating expenses increased $69 million primarily due to:
  - Higher transmission expenses of $30 million primarily due to increases in network transmission expenses at the Ohio Companies. The difference between current transmission revenues and transmission costs incurred are deferred for future recovery, resulting in no material impact on earnings.
  - Higher pension and OPEB costs of $6 million.
  - Higher distribution operating and maintenance expense of $32 million, including increased labor and benefit costs, partially offset by lower storm restoration costs.
  - Impairment charges of $8 million associated with certain non-core assets.

- Depreciation expense increased $9 million due to a higher asset base, partially offset by lower depreciation rates at JCP&L, effective with the implementation of new distribution rates from its distribution base rate case.

- Net amortization of regulatory assets increased $77 million primarily due to:
  - Recovery of storm costs in New Jersey, Pennsylvania, and West Virginia effective with the implementation of new rates as discussed above ($30 million),
  - Higher energy efficiency program cost recovery ($17 million),
  - Higher amortization of above-market NUG costs in Pennsylvania and New Jersey ($14 million),
  - Lower deferral of West Virginia vegetation management expenses ($12 million),
  - Amortization of Pennsylvania legacy meter costs ($8 million), and
  - Higher cost amortization of network transmission expenses ($7 million); partially offset by
  - Lower default generation service cost amortization in Pennsylvania ($20 million).

Other Expense —

Other expense increased $7 million in the third quarter of 2015 compared to the same period of 2014 primarily due to higher OTTI and lower investment income on NDT investments.

Income Taxes —

Regulated Distribution’s effective tax rate was 36.9% and 35.3% for the quarter ended September 30, 2015 and 2014, respectively. The increase in the effective tax rate resulted from changes in state apportionment factors and tax benefits recognized in 2014.

Regulated Transmission — Third Quarter 2015 Compared with Third Quarter 2014

Net income increased $15 million in the third quarter of 2015 compared to the same period of 2014. Higher transmission revenues associated with ATSI's "forward looking" rate, reflecting incremental cost of service and rate base recovery, were partially offset by higher interest costs.

Revenues —

Total revenues increased $51 million principally due to higher revenue requirements at ATSI and TrAIL, reflecting incremental cost of service and rate base recovery. Effective January 1, 2015, ATSI's formula rate transitioned to a "forward looking" approach, where transmission revenues are based on actual costs, subject to a provision for rate refund.

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

Three Months Ended September 30,

Revenues by Transmission Asset Owner	2015	2014	Increase (Decrease)
	(In millions)		
ATSI	$110	$66	$44
TrAIL	60	52	8
PATH	3	4	(1)
Utilities	75	75	—
Total Revenues	$248	$197	$51

Operating Expenses —

Total operating expenses increased $15 million principally due to higher property taxes and depreciation expense at ATSI, which are recovered through ATSI's "forward looking" rate.

Other Expense —

Total other expense increased $10 million in the third quarter of 2015 as compared to the same period of 2014 primarily due to lower capitalized financing costs of $5 million resulting from lower capital expenditures along with increased interest expense of $5 million resulting from debt issuances of $400 million at ATSI in 2014, the proceeds of which, in part, paid off short-term borrowings.

Income Taxes —

Regulated Transmission’s effective tax rate was 36.9% and 35.3% for the quarter ended September 30, 2015 and 2014, respectively. The increase in the effective tax rate resulted from tax benefits recognized in 2014 primarily associated with changes in state apportionment factors and realized tax benefits recognized in 2014.

CES — Third Quarter 2015 Compared with Third Quarter 2014

Net income increased $74 million in the third quarter of 2015, compared to the same period of 2014, primarily resulting from higher capacity revenues and lower operating costs, partially offset by lower contract sales. Additionally, although wholesale short-term transactions increased year-over-year, low average spot market energy prices reduced the economic dispatch of fossil generating units, limiting additional wholesale sales.

Revenues —

Total revenues decreased $131 million in the third quarter of 2015, compared to the same period of 2014, primarily due to decreased contract sales volumes in line with CES' strategy to more effectively hedge its generation. Revenues were impacted by higher unit prices as a result of the change in sales channel mix and increased channel pricing, as well as higher capacity revenues, as further described below.

The change in total revenues resulted from the following sources:

	Three Months Ended September 30,		Increase	
Revenues by Type of Service	2015	2014	(Decrease)	
	(In millions)			
Contract Sales:				
Direct	$296	$547	$(251	)
Governmental Aggregation	296	327	(31	)
Mass Market	62	112	(50	)
POLR	141	220	(79	)
Structured Sales	170	161	9	
Total Contract Sales	965	1,367	(402	)
Wholesale	429	151	278	
Transmission	23	36	(13	)
Other	51	45	6	
Total Revenues	$1,468	$1,599	$(131	)

MWH Sales by Channel	Three Months Ended September 30, 2015	2014	Increase (Decrease)
	(In thousands)		
Contract Sales:			
Direct	5,541	10,397	(46.7)%
Governmental Aggregation	4,226	4,992	(15.3)%
Mass Market	906	1,664	(45.6)%
POLR	2,168	3,635	(40.4)%
Structured Sales	3,893	3,459	12.5%
Total Contract Sales	16,734	24,147	(30.7)%
Wholesale	3,156	236	1,237.3%
Total MWH Sales	19,890	24,383	(18.4)%

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	$(256)	$5	$—	$—	$(251)
Governmental Aggregation	(50)	19	—	—	(31)
Mass Market	(51)	1	—	—	(50)
POLR	(89)	10	—	—	(79)
Structured Sales	21	(12)	—	—	9
Wholesale	75	9	40	154	278

The Direct, Governmental Aggregation and Mass Market customer base was 1.7 million as of September 30, 2015, compared to 2.3 million as of September 30, 2014, reflecting CES' efforts to reposition its sales portfolio. Additionally, although unit pricing was higher year-over-year in the Direct, Governmental Aggregation, Mass Market, and POLR channels, the increase was primarily attributable to higher capacity expense as discussed below, which is a component of the retail price.

The decrease in POLR sales of $79 million was due to lower volumes, partially offset by higher rates associated with recent POLR auctions. Structured Sales increased $9 million primarily due to higher structured transaction volumes, partially offset by the impact of lower market prices.

Wholesale revenues increased $278 million, primarily due to an increase in capacity revenue from higher capacity prices, gains on financially settled contracts, and an increase in short-term (net hourly position) transactions at higher rates.

Other revenue increased $6 million primarily due to higher lease revenues from additional repurchased equity interests in affiliated sale and leasebacks in November of 2014. CES earns lease revenue associated with the equity interests it purchased.

Operating Expenses —

Total operating expenses decreased $284 million in the third quarter of 2015 due to the following:

- Fuel costs decreased $43 million primarily due to lower economic dispatch of fossil units resulting from low wholesale spot market energy prices and lower unit prices.
- Purchased power costs decreased $138 million due to lower volumes ($147 million) resulting from lower contract sales and lower net losses on financially settled contracts ($13 million), partially offset by higher capacity expenses ($22 million). Lower volumes were primarily due to decreased load requirements resulting from CES' revised sales strategy, partially offset by decreased fossil generation discussed above. The increase in capacity expense, which is a component of CES' retail price, was primarily the result of higher capacity rates associated with CES' retail sales obligations.

- Fossil operating costs increased $5 million primarily due to higher employee benefit expenses.

- Nuclear operating costs increased $30 million primarily due to outage and contractor costs associated with the refueling outage at Beaver Valley Unit 2 that began in September 2015, and higher employee benefit expenses. There was no refueling outage in the same period of 2014.

- Transmission expenses decreased $53 million primarily due to decreased load requirements and lower operating reserve and market-based ancillary costs.
- General taxes decreased $5 million primarily due to lower gross receipts taxes associated with decreased retail sales volumes.

- Other operating expenses decreased $78 million primarily due to a decrease in mark-to-market expenses on commodity contract positions.

Other Expense —

Total other expense increased $34 million in the third quarter of 2015, as compared to the same period of 2014, primarily due to higher OTTI on NDT investments.

Income Taxes —

CES' effective tax rate was 36.7% and 35.3% for the quarter ended September 30, 2015 and 2014, respectively. The increase in the effective tax rate resulted from changes in state apportionment factors and tax benefits recognized in 2014.

Corporate / Other — Third Quarter 2015 Compared with Third Quarter 2014

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 $34 million decrease in earnings in the third quarter of 2015, compared to the same period of 2014, primarily due to increased costs associated with environmental remediation at legacy plants and the absence of tax benefits recognized in 2014 associated with an IRS-approved change in accounting method that increased the tax basis in certain assets resulting in higher future tax deductions.

Summary of Results of Operations — First Nine Months of 2015 Compared with First Nine Months of 2014

Financial results for FirstEnergy's business segments in the first nine months of 2015 and 2014 were as follows:

First Nine Months 2015 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$7,277	$ 755	$3,381	$(129)	$11,284
Other	148	—	155	(102)	201
Internal	—	—	563	(563)	—
Total Revenues	7,425	755	4,099	(794)	11,485
Operating Expenses:					
Fuel	406	—	972	—	1,378
Purchased power	2,761	—	1,113	(563)	3,311
Other operating expenses	1,677	112	1,282	(248)	2,823
Provision for depreciation	516	116	293	44	969
Amortization of regulatory assets, net	196	5	—	—	201
General taxes	536	73	112	26	747
Total Operating Expenses	6,092	306	3,772	(741)	9,429
Operating Income	1,333	449	327	(53)	2,056
Other Income (Expense):					
Loss on debt redemptions	—	—	—	—	—
Investment income (loss)	33	—	(23)	(24)	(14)
Interest expense	(439)	(119)	(144)	(144)	(846)
Capitalized financing costs	21	36	29	7	93
Total Other Expense	(385)	(83)	(138)	(161)	(767)
Income From Continuing Operations Before Income Taxes	948	366	189	(214)	1,289
Income taxes	350	135	70	(70)	485
Income From Continuing Operations	598	231	119	(144)	804
Discontinued Operations, net of tax	—	—	—	—	—
Net Income	$598	$ 231	$119	$(144)	$804

First Nine Months 2014 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/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 (Benefits)	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

Changes Between First Nine Months 2015 and First Nine Months 2014 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$455	$ 185	$(718)	$ 16	$(62)
Other	(2)	—	15	(32)	(19)
Internal	—	—	(61)	61	—
Total Revenues	453	185	(764)	45	(81)
Operating Expenses:					
Fuel	(35)	—	(298)	—	(333)
Purchased power	161	—	(637)	61	(415)
Other operating expenses	97	9	(343)	(1)	(238)
Provision for depreciation	25	23	6	11	65
Amortization of regulatory assets, net	178	(4)	—	—	174
General taxes	8	21	(21)	1	9
Total Operating Expenses	434	49	(1,293)	72	(738)
Operating Income	19	136	529	(27)	657
Other Income (Expense):					
Loss on debt redemptions	—	—	8	—	8
Investment income	(11)	—	(69)	(1)	(81)
Interest expense	6	(29)	(1)	(20)	(44)
Capitalized financing costs	9	(2)	1	(4)	4
Total Other Expense	4	(31)	(61)	(25)	(113)
Income From Continuing Operations Before Income Taxes	23	105	468	(52)	544
Income taxes	24	43	172	20	259
Income From Continuing Operations	(1)	62	296	(72)	285
Discontinued Operations, net of tax	—	—	(86)	—	(86)
Net Income	$(1)	$ 62	$210	$ (72)	$199

Regulated Distribution — First Nine Months of 2015 Compared with First Nine Months of 2014

Regulated Distribution's net income decreased $1 million in the first nine months of 2015 as compared to the same period of 2014, primarily reflecting increased operating expenses and a higher effective tax rate, partially offset by higher distribution services revenues resulting from higher weather-related volumes, a net increase in new rates implemented in 2015 at certain operating companies, and an increase in the Ohio Companies' DCR.

Revenues —

The $453 million increase in total revenues resulted from the following sources:

Revenues by Type of Service	Nine Months Ended September 30, 2015	2014	Increase (Decrease)
	(In millions)		
Distribution services	$3,073	$2,792	$281
Generation sales:			
Retail	3,331	3,097	234
Wholesale	390	541	(151)
Total generation sales	3,721	3,638	83
Transmission sales:			
Retail	393	268	125
Wholesale	90	124	(34)
Total transmission sales	483	392	91
Other	148	150	(2)
Total Revenues	$7,425	$6,972	$453

Distribution services revenues increased $281 million primarily resulting from approved base distribution rate increases in Pennsylvania, effective May 3, 2015, and for MP and PE in West Virginia, effective February 25, 2015, partially offset by a distribution rate decrease at JCP&L, including the recovery of 2011 and 2012 storm costs, effective April 1, 2015. Additionally, distribution services revenues increased resulting from higher weather-related usage as described below, higher cost recovery for above market NUG costs, the Ohio Companies' DCR, and certain energy efficiency programs for the Pennsylvania Companies, which reflected a rate decrease in 2014. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	Nine Months Ended September 30, 2015	2014	Increase (Decrease)
	(In thousands)		
Residential	42,706	41,616	2.6%
Commercial	33,006	32,489	1.6%
Industrial	38,149	38,667	(1.3)%
Other	438	439	(0.2)%
Total Electric Distribution MWH Deliveries	114,299	113,211	1.0%

Higher distribution deliveries to residential and commercial customers reflect increased weather-related usage resulting from cooling degree days that were 33% above 2014, and 18% above normal, partially offset by heating degree days that were 1.6% below the same period of 2014, but 12% above normal. The increase in residential deliveries associated with weather-related usage was partially offset by declining average customer usage due, in part, to increasing energy efficiency mandates. Deliveries to industrial customers decreased 1.3%, as the increase from shale and petroleum customer usage was more than offset by a decrease from steel customer usage.

The following table summarizes the price and volume factors contributing to the $83 million increase in generation revenues for the first nine months of 2015 compared to the same period of 2014:

Source of Change in Generation Revenues	Increase (Decrease) (In millions)
Retail:	
Effect of increase in sales volumes	$200
Change in prices	34
	234
Wholesale:	
Effect of decrease in sales volumes	(127)
Change in prices	(71)
Capacity Revenue	47
	(151)
Increase in Generation Revenues	$83

The increase in retail generation sales volumes was primarily due to lower customer shopping in Ohio, Pennsylvania, and New Jersey and an increase in weather-related usage, as described above. Total generation provided by alternative suppliers as a percentage of total MWH deliveries decreased to 80% from 81% for the Ohio Companies, 65% from 67% for the Pennsylvania Companies and 49% from 52% for JCP&L. The increase in prices primarily resulted from higher default service auction results.

Wholesale generation revenues decreased $151 million in the first nine months of 2015, as compared to the same period of 2014, primarily reflecting decreased volume associated with the termination of certain NUG contracts at JCP&L and PN and lower economic dispatch of fossil generating units associated with low spot market energy prices. Partially offsetting the decrease was an increase in capacity revenue resulting from higher capacity prices. The difference between current wholesale generation revenues and certain energy costs incurred are deferred for future recovery, with no material impact to earnings.

The increase in retail transmission revenues of $125 million was primarily due to an increase in the Ohio Companies' NMB transmission rider revenues. The NMB rider recovers network transmission integration service costs from all distribution customers at the Ohio Companies, with no material impact to earnings. The decrease in wholesale transmission revenues of $34 million primarily relates to lower congestion revenue resulting from the impact of market conditions related to extreme weather events in 2014.

Operating Expenses —

Total operating expenses increased $434 million primarily due to the following:

- Fuel expense decreased $35 million in the first nine months of 2015, as compared to the same period of 2014, primarily related to lower economic dispatch resulting from low spot market energy prices.

- Purchased power costs were $161 million higher during the first nine months of 2015, as compared to the same period of 2014, primarily due to increased volumes reflecting decreased customer shopping, higher unit costs related to higher default service auction results, and higher capacity expense at MP, partially offset by lower purchases resulting from the termination of certain NUG contracts at JCP&L and PN.

Source of Change in Purchased Power	Increase (Decrease) (In millions)
Purchases from non-affiliates:	
Change due to increased unit costs	$25
Change due to increased volumes	149
	174
Purchases from affiliates:	
Change due to decreased unit costs	(16)
Change due to volumes	(45)
	(61)
Capacity Expense	35
Amortization of deferred costs	13
Increase in Purchased Power Costs	$161

- Other operating expenses increased $97 million primarily due to:
- Higher transmission expenses of $29 million primarily due to an increase in network transmission expenses at the Ohio Companies, partially offset by lower congestion expenses at MP. The difference between current transmission revenues and transmission costs incurred are deferred for future recovery, resulting in no material impact on current period earnings.
- Increased regulated generation operating and maintenance expenses of $7 million, reflecting higher planned outage expenses in the first nine months of 2015 as compared to the same period in 2014.
- Higher pension and OPEB costs of $18 million.
- Higher distribution operating and maintenance expense of $37 million, reflecting increased employee benefit costs partially offset by lower storm restoration costs.
- Impairment charges of $8 million associated with certain non-core assets.

- Depreciation expense increased $25 million due to a higher asset base, partially offset by lower depreciation rates at JCP&L effective with the implementation of new rates from its distribution base rate case.

- Net amortization of regulatory assets increased $178 million primarily due to:
- Recovery of storm costs in New Jersey, Pennsylvania, and West Virginia effective with the implementation of new rates as discussed above ($50 million),
- Higher energy efficiency program cost recovery ($60 million),
- Higher amortizations of above-market NUG costs in Pennsylvania and New Jersey ($33 million),
- Higher default generation service cost amortization ($23 million),
- Lower deferral of West Virginia vegetation management expenses ($14 million), and
- Amortization of Pennsylvania legacy meter costs ($11 million); partially offset by
- Lower cost amortization of Ohio network transmission expenses ($17 million).

Other Expense —

Other expense decreased $4 million in the first nine months of 2015 primarily due to lower interest expense on short-term borrowings, as well as higher capitalized financing costs resulting from higher rates used for borrowed funds, partially offset by higher OTTI on NDT investments.

Income Taxes —

Regulated Distribution’s effective tax rate was 36.9% and 35.2% for the first nine months of 2015 and 2014, respectively. The increase in the effective tax rate resulted from changes in state apportionment factors and realized tax benefits recognized in 2014.

Regulated Transmission — First Nine Months of 2015 Compared with First Nine Months of 2014

Net income increased $62 million in the first nine months of 2015 compared to the same period of 2014. Higher transmission revenues associated with ATSI's "forward looking" rate, reflecting incremental cost of service and rate base recovery, were partially offset by higher interest costs.

Revenues —

Total revenues increased $185 million principally due to higher revenue requirements at ATSI and TrAIL, reflecting incremental cost of service and rate base recovery, resulting from their annual rate filings. Effective January 1, 2015, ATSI's formula rate calculation transitioned to a "forward looking" approach, where transmission revenues are based on actual costs, subject to a provision for rate refund.

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

	Nine Months Ended September 30,		
Revenues by Transmission Asset Owner	2015	2014	Increase
	(In millions)		
ATSI	$333	$176	$157
TrAIL	186	161	25
PATH	10	9	1
Utilities	226	224	2
Total Revenues	$755	$570	$185

Operating Expenses —

Total operating expenses increased $49 million principally due to higher property taxes and depreciation expense at ATSI, which are recovered through ATSI's "forward looking" rate.

Other Expense —

Other expense increased $31 million in the first nine months of 2015 compared to the same period of 2014 primarily due to increased interest expense resulting from debt issuances of $1.0 billion at FET and $400 million at ATSI, the proceeds of which, in part, paid off short term borrowings.

Income Taxes —

Regulated Transmission’s effective tax rate was 36.9% and 35.2% for the first nine months of 2015 and 2014, respectively. The increase in the effective tax rate resulted from changes in state apportionment factors and realized tax benefits recognized in 2014.

CES — First Nine Months of 2015 Compared with First Nine Months of 2014

Operating results increased $210 million in the first nine months of 2015, compared to the same period of 2014, primarily from higher capacity revenues and the absence of the impact of the extreme market conditions and unplanned outages in 2014 resulting in higher costs to serve contract sales. Subsequent to the first quarter of 2014, CES began to reduce its exposure to weather-sensitive loads and more effectively hedge its generation. As a result of that revised strategy, CES was able to successfully mitigate the extreme weather conditions that occurred in February 2015 by more effectively using its generation to supply higher customer usage as compared to the first quarter of 2014 when CES purchased power at higher prices to supply increased customer usage. Additionally, operating results were impacted by lower settlement and termination costs related to coal and transportation contracts, and a $78 million after-tax gain on the sale of certain hydroelectric facilities in February 2014.

Revenues —

Total revenues decreased $764 million in the first nine months of 2015, compared to the same period of 2014, primarily due to decreased sales volumes in line with CES' strategy to more effectively hedge its generation. Revenues were also impacted by higher unit prices compared to 2014 as a result of increased channel pricing as well as higher capacity revenues, as further described below.

The change in total revenues resulted from the following sources:

Revenues by Type of Service	Nine Months Ended September 30, 2015	2014	Increase (Decrease)
	(In millions)		
Contract Sales:			
Direct	$1,014	$1,879	$(865)
Governmental Aggregation	802	924	(122)
Mass Market	222	354	(132)
POLR	585	690	(105)
Structured Sales	429	376	53
Total Contract Sales	3,052	4,223	(1,171)
Wholesale	776	313	463
Transmission	116	187	(71)
Other	155	140	15
Total Revenues	$4,099	$4,863	$(764)

MWH Sales by Channel	Nine Months Ended September 30, 2015	2014	Increase (Decrease)
	(In thousands)		
Contract Sales:			
Direct	18,860	35,069	(46.2)%
Governmental Aggregation	12,278	15,413	(20.3)%
Mass Market	3,246	5,294	(38.7)%
POLR	9,910	11,921	(16.9)%
Structured Sales	9,790	9,614	1.8%
Total Contract Sales	54,084	77,311	(30.0)%
Wholesale	4,023	268	1,401.1%
Total MWH Sales	58,107	77,579	(25.1)%

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	$(868)	$3	$—	$—	$(865)
Governmental Aggregation	(187)	65	—	—	(122)
Mass Market	(137)	5	—	—	(132)
POLR	(117)	12	—	—	(105)
Structured Sales	7	46	—	—	53
Wholesale	102	8	46	307	463

Lower sales volumes in the Direct, Governmental Aggregation, and Mass Market sales channels primarily reflect CES' efforts to reposition its sales portfolio by reducing exposure to weather-sensitive load. Although unit pricing was higher year-over-year in the Direct, Governmental Aggregation, and Mass Market channels, the increase was primarily attributable to higher capacity expense as discussed below, which is a component of the retail price. The increase in Direct unit prices was partially offset by ancillary pass-through revenues recognized in 2014 associated with PJM expenses incurred in January 2014.

The decrease in POLR sales of $105 million was due to lower volumes, partially offset by higher rates associated with recent POLR auctions. Structured Sales increased $53 million primarily due to market conditions that increased the gains on various structured financial sales contracts and higher structured transaction volumes.

Wholesale revenues increased $463 million, primarily due to an increase in capacity revenue from higher capacity prices and an increase in short-term (net hourly position) transactions at higher rates. Although realized wholesale prices were higher in the first nine months of 2015, as compared to the same period of 2014, spot market energy prices were low and limited wholesale sales.

Transmission revenue decreased $71 million in the first nine months of 2015, as compared to the same period of 2014, primarily due to lower congestion revenue resulting from market conditions related to extreme weather events in 2014.

Other revenue increased $15 million primarily due to higher lease revenues from additional repurchased equity interests in affiliated sale and leasebacks in November of 2014. CES earns lease revenue associated with the equity interests it purchased.

Operating Expenses —

Total operating expenses decreased $1,293 million in the first nine months of 2015 due to the following:

- Fuel costs decreased $298 million primarily due to lower economic dispatch of fossil units resulting from low wholesale spot market energy prices. Lower nuclear unit prices also contributed to the decrease, resulting from the suspension of the DOE nuclear disposal fee, which became effective May 16, 2014. Additionally, fuel costs were impacted by a decrease in settlement and termination costs related to coal and transportation contracts. Terminations and settlements of coal and transportation contracts resulted in a pre-tax loss of $85 million in the first nine months of 2014.
- Purchased power costs decreased $637 million due to lower volumes ($760 million) and lower unit prices ($8 million), partially offset by higher capacity expenses ($131 million). Lower volumes were primarily due to decreased load requirements resulting from CES' sales strategy, partially offset by decreased fossil generation discussed above. The increase in capacity expense, which is a component of CES' retail price, was primarily the result of higher capacity rates associated with CES' retail sales obligations.
- Fossil operating costs decreased $7 million primarily due to fewer planned and unplanned outages for the nine months ended September 30, 2015 as compared to the same period of 2014, partially offset by higher employee benefit expenses.
- Nuclear operating costs increased $49 million as a result of higher employee benefit expenses and higher planned outage costs.
- Transmission expenses decreased $218 million primarily due to lower operating reserve and market-based ancillary costs associated with market conditions resulting from the extreme weather events in January 2014, of which a portion were passed through to commercial and industrial customers, as discussed above.
- Depreciation expense increased $6 million as a result of a higher asset base from projects such as MATS compliance and the Davis-Besse steam generator replacement completed in May 2014.
- General taxes decreased $21 million primarily due to lower gross receipts taxes associated with decreased retail sales volumes.

- Other operating expenses decreased $167 million primarily due to a $127 million decrease in mark-to-market expenses on commodity contract positions and a $56 million decrease in retail-related costs, partially offset by a $16 million impairment charge associated with non-core assets.

Other Expense —

Total other expense in the first nine months of 2015 increased $61 million, compared to the same period of 2014, primarily due to higher OTTI on NDT investments and higher interest expense, partially offset by the absence of an $8 million loss on debt redemptions incurred in the first nine months of 2014.

Discontinued Operations —

Discontinued operations decreased operating results $86 million in the first nine months of 2015, compared to the same period of 2014, primarily due to a pre-tax gain of approximately $142 million ($78 million after-tax) associated with the sale of certain hydroelectric assets on February 12, 2014.

Income Taxes (Benefits) —

CES' effective tax rate was 37.0% and 36.6% for the first nine months of 2015 and 2014, respectively. The increase in the effective tax rate resulted from changes in state apportionment factors and realized tax benefits recognized in 2014.

Corporate / Other — First Nine Months of 2015 Compared with First Nine Months of 2014

Financial results from other operating segments and reconciling items resulted in a $72 million decrease in net income in the first nine months of 2015 compared to the same period of 2014 primarily due to costs associated with environmental remediation at legacy plants, higher interest expense and lower income tax benefits. The increased interest expense primarily related to a new $1 billion term loan entered into in March 2014 and a gain on the termination of interest rate swap arrangements recognized in the second quarter of 2014. Lower income tax benefits primarily resulted from an IRS-approved change in accounting method that increased the tax basis in certain assets resulting in higher future tax deductions, a reduction in state deferred tax liabilities resulting from changes in state apportionment factors, as well as the elimination of certain future tax liabilities associated with basis differences recognized in the first nine months of 2014.

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, 2015 and December 31, 2014, and the changes during the nine months ended September 30, 2015:

Regulatory Assets (Liabilities) by Source	September 30, 2015	December 31, 2014	Increase (Decrease)
	(In millions)		
Regulatory transition costs	$196	$240	$(44)
Customer receivables for future income taxes	376	370	6
Nuclear decommissioning and spent fuel disposal costs	(274)	(305)	31
Asset removal costs	(367)	(254)	(113)
Deferred transmission costs	101	90	11
Deferred generation costs	256	281	(25)
Deferred distribution costs	345	182	163
Contract valuations	185	153	32
Storm-related costs	423	465	(42)
Other	189	189	—
Net Regulatory Assets included on the Consolidated Balance Sheets	$1,430	$1,411	$19

Regulatory assets that do not earn a current return totaled approximately $148 million and $488 million as of September 30, 2015 and December 31, 2014, respectively, primarily related to storm damage costs. JCP&L's regulatory asset related to 2011 and 2012 storm damage costs of $329 million began earning a return on April 1, 2015. Effective with the approved settlement on April 9, 2015, associated with their general base rate case, the Pennsylvania Companies transferred the net book value of legacy meters from plant in service to regulatory assets, which is being recovered over five years.

As of September 30, 2015 and December 31, 2014, FirstEnergy had approximately $141 million and $243 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 payments, dividend payments, and contributions to its pension plan. In addition to internal sources to fund liquidity and capital requirements for 2015 and beyond, FirstEnergy expects to rely on external sources of funds. Short-term cash requirements not met by cash provided from operations are generally satisfied through short-term borrowings. Long-term cash needs may be met through the issuance of long-term debt and/or equity. FirstEnergy expects that borrowing capacity under credit facilities will continue to be available to manage working capital requirements along with continued access to long-term capital markets. Additionally, FirstEnergy also expects to issue long-term debt at certain Utilities and certain other subsidiaries to, among other things, refinance short-term and maturing debt in the ordinary course, subject to market and other conditions.

Capital expenditures for 2015 are expected to be approximately $2.9 billion. These capital expenditures, including the transmission expansion program discussed below, are expected to be funded with a combination of cash from operations, debt, and, depending on the regulated operating company, capital contributions from its parent. In the future, FirstEnergy may consider equity issuances to fund capital investments in the regulated operations.

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" transmission expansion 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 and physical security and add operating flexibility and capacity, starting with the ATSI system and moving east across FirstEnergy's service territory over time. Regulated Transmission's capital expenditure forecast for 2015 is approximately $970 million, of which $781 million was incurred through the first nine months of 2015. In total, FirstEnergy has identified at least $15 billion in incremental transmission investment opportunities across the 24,000 mile transmission system, making this a continuing platform for investment in the years beyond 2017.

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

As part of an effort to manage costs, FirstEnergy identified both immediate and long-term savings opportunities through its cash flow improvement plan. The cash flow improvement plan identified targeted cash savings of approximately $58 million in 2015, $155 million in 2016 and $240 million annually by 2017, with reductions in operating expenses representing approximately 65% of the savings over the three year period.

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, 2015, 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, 2015, included the following:

Currently Payable Long-Term Debt	(In millions)
PCRBs supported by bank LOCs[1]	$92
Unsecured notes	391
FMBs	215
Unsecured PCRBs[1]	300
Collateralized lease obligation bonds	47
Sinking fund requirements	87
Other notes	16
	$1,148

(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.

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Short-Term Borrowings

FirstEnergy had $1,933 million and $1,799 million of short-term borrowings as of September 30, 2015 and December 31, 2014, respectively. FirstEnergy's available liquidity as of September 30, 2015, was as follows:

Borrower(s)	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy[(1)]	Revolving	March 2019	$3,500	$1,619
FES / AE Supply	Revolving	March 2019	1,500	1,452
FET[(2)]	Revolving	March 2019	1,000	950
		Subtotal	$6,000	$4,021
		Cash	—	59
		Total	$6,000	$4,080

(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) expiring on March 31, 2019.

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, 2015:

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, 2015, 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 May 29, 2020. 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, 2015, 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 rate for borrowings in the first nine months of 2015 were 0.97% per annum for the regulated companies' money pool and 1.64% per annum for the unregulated companies' money pool.

Pollution Control Revenue Bonds

As of September 30, 2015, 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, 2015 were issued by the following bank:

Bank	Aggregate Amount[(1)]	Termination Date	Reimbursements of Draws Due
	(In millions)		
The Bank of Nova Scotia	$92	March 2017	March 2017

(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, 2015:

	Senior Secured		Senior Unsecured		
Issuer	S&P	Moody’s	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, 2015, FE and its subsidiaries could issue additional debt of approximately $5.1 billion and remain within the limitations of the financial covenants required by the Facilities. As of September 30, 2015, FES' incremental debt capacity under its consolidated debt to total capitalization financial covenant is also $5.1 billion given FE's consolidated debt to total capitalization ratio under its Facility.

Changes in Cash Position

As of September 30, 2015, FirstEnergy had $86 million of cash and cash equivalents compared to $85 million of cash and cash equivalents as of December 31, 2014. As of September 30, 2015 and December 31, 2014, FirstEnergy had approximately $67 million and $79 million, respectively, of restricted cash included in Other Current Assets on the Consolidated Balance Sheets.

Cash Flows From Operating Activities

FirstEnergy's most significant source of cash is derived from electric service provided by its utility operating subsidiaries and the sales of energy and related products and services by its unregulated competitive subsidiaries. The most significant use of cash from operating activities is to buy electricity in the wholesale market and pay fuel suppliers, employees, tax authorities, lenders, and others for a wide range of material and services. Net cash provided from operating activities was $2,317 million during the first nine months of 2015 compared with $1,737 million provided from operating activities during the first nine months of 2014. Cash flows from operations increased $580 million in the first nine months of 2015, compared with the same period of 2014, primarily due to lower disbursements for fuel, purchased power, and posted collateral, partially offset by a $143 million contribution to the qualified pension plan and lower retail receipts.

Cash Flows From Financing Activities

In the first nine months of 2015, cash used for financing activities was $29 million compared to $444 million of cash provided from financing activities during the first nine months of 2014. The following table summarizes new debt financing, redemptions and repayments:

	Nine Months Ended September 30,	
Securities Issued or Redeemed / Repaid	2015	2014
	(In millions)	
New Issues		
Term Loan	$200	$1,050
PCRBs	339	878
Unsecured Notes	250	1,850
FMBs	295	—
	$1,084	$3,778
Redemptions / Repayments		
Term Loan	$(200)	$—
PCRBs	(312)	(767)
Unsecured notes	—	(149)
FMBs	(145)	—
Senior secured notes	(124)	(146)
	$(781)	$(1,062)
Short-term borrowings (repayments), net	$134	$(1,783)
Common stock dividend payments	$(455)	$(452)

During the second quarter of 2015, FE refinanced a $200 million variable interest term loan, maturing on December 31, 2016 with a new $200 million variable interest term loan, maturing on May 29, 2020.

On July 1, 2015, FG and NG remarketed approximately $43 million and $296 million, respectively, of PCRBs. The PCRBs were remarketed with fixed interest rates ranging from 3.125% to 4.00% and mandatory put dates ranging from July 2, 2018 to July 1, 2021.

During August 2015, JCP&L issued $250 million of 4.30% senior notes due January 2026. The proceeds received from the issuance of the senior notes were used to repay a portion of JCP&L’s short-term borrowings under the FirstEnergy regulated companies' money pool and an external revolving credit facility.

Also during the second quarter of 2015, WP agreed to sell $150 million of new 4.45% FMBs due September 2045 and PE agreed to sell $145 million of new 4.47% FMBs due August 2045. The transactions closed on September 17, 2015 and August 17, 2015, respectively. The proceeds resulting from the issuance of the WP FMBs were used to repay WP's borrowings under the FirstEnergy regulated companies' money pool and for other general corporate purposes. The proceeds resulting from the issuance of the PE FMBs were used to repay PE's $145 million 5.125% FMBs that matured on August 15, 2015.

On October 16, 2015, TrAIL issued $75 million of 3.76% senior notes due May 2025. The proceeds resulting from the issuance of the senior notes were used: (i) to fund capital expenditures, including with respect to TrAIL's transmission expansion plans; and (ii) for working capital needs and other general business purposes.

Additionally, on October 21, 2015, ATSI issued in total $150 million of senior notes: $75 million of 4.00% senior notes due April 2026 and $75 million of 5.23% senior notes due October 2045. The proceeds resulting from the issuance of the senior notes were used: (i) to fund capital expenditures, including with respect to ATSI's transmission expansion plans; (ii) for working capital needs and other general business purposes; and (iii) to repay borrowings under the FirstEnergy regulated companies' money pool.

Cash Flows From Investing Activities

Cash used for investing activities in the first nine months of 2015 principally represented cash used for property additions. The following table summarizes investing activities for the first nine months of 2015 and the comparable period of 2014:

	Nine Months Ended September 30,		
Cash Used for Investing Activities	2015	2014	Increase (Decrease)
	(In millions)		
Property Additions:			
Regulated Distribution	$884	$780	$104
Regulated Transmission	700	980	(280)
Competitive Energy Services	400	655	(255)
Other and reconciling adjustments	41	58	(17)
Nuclear fuel	101	98	3
Proceeds from asset sales	(20)	(394)	374
Investments	68	40	28
Asset removal costs	111	80	31
Other	2	(7)	9
	$2,287	$2,290	$(3)

Lower property additions were partially offset by a $374 million reduction in proceeds received from asset sales, as 2014 included proceeds from the sale of hydroelectric assets. The decline in property additions were due to the following:

- a decrease of $255 million at CES associated with the Davis-Besse steam generators that were placed into service in May 2014,
- a decrease of $280 million at Regulated Transmission primarily relating to a planned decrease in investments associated with Energizing the Future investment program,
- partially offset by an increase of $104 million at Regulated Distribution relating to utility specific project investments and costs associated with the Pennsylvania smart meter program.

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, 2015, was approximately $3.7 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)	$33
Deferred compensation arrangements	525
Other(2)	19
	577
Subsidiaries' Guarantees	
Energy and Energy-Related Contracts(3)	215
FES' guarantee of NG's nuclear property insurance	98
FES' guarantee of nuclear decommissioning costs	21
FES' guarantee of FG's sale and leaseback obligations	1,796
	2,130
FE's Guarantees on Behalf of Business Ventures	
Global Holding facility	300
Other Assurances	
Surety Bonds - Wholly Owned Subsidiaries	397
Surety Bonds	22
FES' LOC (long-term tax-exempt debt)(4)	93
LOCs(5)	159
	671
Total Guarantees and Other Assurances	$3,678

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

(2) Includes guarantees of $4 million for nuclear decommissioning funding assurances, $8 million for railcar leases and $7 million for various leases.

(3) Includes Energy and Energy-Related Contracts associated with FES of approximately $211 million.

(4) Reflects the $1 million of interest coverage portion of LOCs issued in support of floating rate PCRBs with maturities in 2017 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.

(5) Includes $55 million issued for various terms pursuant to LOC capacity available under FirstEnergy's revolving credit facilities, $88 million issued in connection with energy and energy related contracts, $2 million issued in connection with railcar leases, $8 million pledged in connection with the sale and leaseback of Beaver Valley Unit 2 by OE and $6 million pledged in connection with the sale and leaseback of Perry by OE.

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

Collateral and Contingent-Related Features

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

Bilateral agreements and derivative instruments entered into by FE and its subsidiaries have margining provisions that require posting of collateral. Based on FES' power portfolio exposures as of September 30, 2015, FES has posted collateral, including LOC, of $223 million. The Regulated Distribution segment has posted collateral of $1 million.

These credit-risk-related contingent features, or the margining provisions within bilateral agreements, 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, which is the ability to secure additional collateral when needed, could be required.

Subsequent to the occurrence of a senior unsecured credit rating downgrade to below S&P's BBB- and Moody's Baa3, or a “material adverse event,” the immediate posting of collateral or accelerated payments may be required of FE or its subsidiaries. The following table discloses the additional credit contingent contractual obligations that may be required under certain events as of September 30, 2015:

Collateral Provisions	FES	AE Supply	Utilities	Total
	(In millions)			
Split Rating (One rating agency's rating below investment grade)	$195	$6	$51	$252
BB+/Ba1 Credit Ratings	$228	$6	$51	$285
Full impact of credit contingent contractual obligations	$321	$15	$51	$387

Excluded from the preceding table are the potential collateral obligations due to affiliate transactions between the Regulated Distribution segment and CES segment. As of September 30, 2015, 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 $11 million with affiliated parties.

Other Commitments and Contingencies

FirstEnergy is a guarantor under a syndicated senior secured term loan facility due March 3, 2020, under which Global Holding borrowed $300 million. In addition to FirstEnergy, Signal Peak, Global Rail, Global Mining Group, LLC and Global Coal Sales Group, LLC, each being a direct or indirect subsidiary of Global Holding, continue to provide their joint and several guaranties of the obligations of Global Holding under the 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 under the current facility as collateral.

During the first quarter of 2015, a subsidiary of Global Holding eliminated its right to put 2 million tons annually through 2024 from the Signal Peak mine to FG in exchange for FirstEnergy extending its guarantee under Global Holding's $300 million senior secured term loan facility through 2020, resulting in a pre-tax charge of $24 million. See Note 7, Variable Interest Entities, for additional information regarding FEV's investment in Global Holding.

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, 2015, 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.

As of September 30, 2015, FirstEnergy's leasehold interest was 3.75% of Perry Unit 1, 93.83% of Bruce Mansfield Unit 1 and 2.60% of Beaver Valley Unit 2.

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 net commodity derivative contracts assets and liabilities as of September 30, 2015 are summarized by year in the following table:

Source of Information-Fair Value by Contract Year	2015	2016	2017	2018	2019	Thereafter	Total
	(In millions)						
Prices actively quoted[1]	$(4)	$(2)	$—	$—	$—	$—	$(6)
Other external sources[2]	(6)	(2)	4	(22)	—	—	(26)
Prices based on models	(3)	8	2	—	(22)	(7)	(22)
Total[3]	$(13)	$4	$6	$(22)	$(22)	$(7)	$(54)

(1) Represents exchange traded New York Mercantile Exchange futures and options.
(2) Primarily represents contracts based on broker and ICE quotes.
(3) Includes $(143) 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, 2015, not subject to regulatory accounting, a 10% adverse change in commodity prices would increase net income by approximately $27 million during the next 12 months.

Equity Price Risk

As of September 30, 2015, the FirstEnergy pension plan assets were allocated approximately as follows: 41% in equity securities, 37% in fixed income securities, 8% in absolute return strategies, 10% in real estate and 4% 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, 2015, FirstEnergy made a $143 million contribution to its qualified pension plan. See Note 4, Pension 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, 2015, FirstEnergy's pension plan assets incurred losses of approximately 3.50% 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, 2015, approximately 69% of the funds were invested in fixed income securities, 28% of the funds were invested in equity securities and 3% 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 $1,571 million, $651 million and $61 million for fixed income securities, equity securities and short-term investments, respectively, as of September 30, 2015, excluding $(4) million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $65 million reduction in fair value as of September 30, 2015. 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, 2015, FirstEnergy contributed approximately $15 million 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, 2015, 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 $250 million to $450 million assuming a discount rate of approximately 4.50% to 4.25%, respectively, and a loss on plan assets of 3.50% based on actual investment performance through September 30, 2015, as discussed above.

CREDIT RISK

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

Wholesale Credit Risk

FirstEnergy and FES measure wholesale credit risk as the replacement cost for derivatives in power, natural gas, coal and emission allowances, adjusted for amounts owed to, or due from, counterparties for settled transactions. The replacement cost of open positions represents unrealized gains, net of any unrealized losses, where FirstEnergy and FES have a legally enforceable right of offset. FirstEnergy and FES monitor and manage the credit risk of wholesale marketing, risk management and energy transacting operations through credit policies and procedures, which include an established credit approval process, daily monitoring of counterparty credit limits, the use of credit mitigation measures such as margin, collateral and the use of master netting agreements. The majority of FirstEnergy's and FES' energy contract counterparties maintain investment-grade credit ratings.

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 SOS supply for PE customers have expired, service continues in the same manner until changed by order of the MDPSC. 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, and requiring each electric utility to file a plan every three years. PE's current plan, covering the three-year period 2015-2017, was approved by the MDPSC on December 23, 2014. The costs of the 2015-2017 plan are expected to be approximately $66 million for that three-year period, of which $13 million was incurred through September 2015. On July 16, 2015, the MDPSC issued an order setting new incremental energy savings goals for 2017 and beyond, beginning with the level of savings achieved under PE's current plan for 2016, and ramping up 0.2% per year thereafter to reach 2%. 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.

On February 27, 2013, the MDPSC issued an order (the February 27 Order) requiring the Maryland electric utilities to submit analyses relating to the costs and benefits of making further system and staffing enhancements in order to attempt to reduce storm outage durations. The order further required the Staff of the MDPSC to report on possible performance-based rate structures and to propose additional rules relating to feeder performance standards, outage communication and reporting, and sharing of special needs customer information. PE's responsive filings 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 of the MDPSC 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 of the MDPSC. In addition, the Staff of the MDPSC 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 issued a ruling on any of those matters.

On March 3, 2014, pursuant to the MDPSC's regulations, PE filed its recommendations for SAIDI and SAIFI standards to apply during the period 2016-2019. The MDPSC directed the Staff of the MDPSC to file an analysis and recommendations with respect to the proposed 2016-2019 SAIDI and SAIFI standards and any related rule changes which the Staff of the MDPSC recommended. The Staff of the MDPSC made its filing on July 10, 2015, and recommended that PE be required to improve its SAIDI results by approximately 20% by 2019. The MDPSC held a hearing on the Staff's analysis and recommendations on September 1-2, 2015, and approved PE's revised proposal for an improvement of 8.6% in its SAIDI standard by 2019 and maintained its SAIFI standard at 2015 levels.

On April 1, 2015, PE filed its annual report on its performance relative to various service reliability standards set forth in the MDPSC’s regulations. The MDPSC held a hearing on the reports filed by PE and the other electric utilities in Maryland on August 24, 2015, and has not yet issued an order on this matter.

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 is comprised of two components, procured through separate, annually held descending clock auctions, the results of which are approved by the NJBPU. One BGS component reflects hourly real time energy prices and is available for larger commercial and industrial customers. The second BGS component provides a fixed price service and is intended for smaller commercial and residential customers. All New Jersey EDCs participate in this competitive BGS procurement process and recover BGS costs directly from customers as a charge separate from base rates.

On March 26, 2015, the NJBPU entered final orders which together provided an overall reduction in JCP&L's annual revenues of approximately $34 million, effective April 1, 2015. The final order in JCP&L's base rate case proceeding directed an annual base rate revenue reduction of approximately $115 million, including recovery of 2011 storm costs and the application of the NJBPU's modified CTA policy approved in the generic CTA proceeding referred to below. Additionally, the final order in the generic proceeding established to review JCP&L's major storm events of 2011 and 2012 approved the recovery of 2012 storm costs of $580 million resulting in an increase in annual revenues of approximately $81 million. JCP&L is required to file another base rate case no later than April 1, 2017. The NJBPU also directed that certain studies be completed. On July 22, 2015, the NJBPU approved the NJBPU staff's recommendation to implement such studies, which will include operational and financial components and is expected to take approximately one year to complete.

In an Order issued October 22, 2014, in a generic proceeding to review its policies with respect to the use of a CTA in base rate cases (Generic CTA proceeding), the NJBPU stated that it would continue to apply its current CTA policy in base rate cases, subject to incorporating the following modifications: (i) calculating savings using a five-year look back from the beginning of the test year; (ii) allocating savings with 75% retained by the company and 25% allocated to rate payers; and (iii) excluding transmission assets of electric distribution companies in the savings calculation. On November 5, 2014, the Division of Rate Counsel appealed the NJBPU Order regarding the Generic CTA proceeding to the New Jersey Superior Court and JCP&L has filed to participate as a respondent in that proceeding. Briefing has been completed, and oral argument has not yet been scheduled.

On June 19, 2015, JCP&L, along with PN, ME, FET and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT, a new transmission-only subsidiary of FET. Evidentiary hearings are scheduled to commence before the NJBPU in February 2016. A final decision from the NJBPU is expected by mid-2016. See Transfer of Transmission Assets to MAIT in FERC Matters below for further discussion of this transaction.

OHIO

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

- Continuing the current base distribution rate freeze through May 31, 2016;
- Continues collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs;
- Continuing to provide economic development and assistance to low-income customers for the two-year plan period at levels established in the prior ESP;
- A 6% generation rate discount to certain low income customers provided by the Ohio Companies through a bilateral wholesale contract with FES (FES is one of the wholesale suppliers to the Ohio Companies);
- Continuing to provide power to non-shopping customers at a market-based price set through an auction process;
- Continuing Rider DCR that allows continued investment in the distribution system for the benefit of customers;
- Continuing commitment not to recover from retail customers certain costs related to transmission cost allocations for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of costs avoided by customers for certain types of products totals $360 million, subject to the outcome of certain FERC proceedings;
- Securing generation supply for a longer period of time by conducting an auction for a three-year period rather than a one-year period, in each of October 2012 and January 2013, to mitigate any potential price spikes for the Ohio Companies' utility customers who do not switch to a competitive generation supplier; and
- Extending the recovery period for costs associated with purchasing RECs mandated by SB221, Ohio's renewable energy and energy efficiency standard, through the end of the new ESP 3 period. This is expected to initially reduce the monthly renewable energy charge for all non-shopping utility customers of the Ohio Companies by spreading out the costs over the entire ESP period.

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

The Ohio Companies filed an application with the PUCO on August 4, 2014 seeking approval of their ESP IV entitled Powering Ohio's Progress. The Ohio Companies filed a partial Stipulation and Recommendation on December 22, 2014, a Supplemental Stipulation and Recommendation on May 28, 2015, and a Second Supplemental Stipulation and Recommendation on June 4, 2015. The evidentiary hearing on the ESP IV commenced on August 31, 2015.

The material terms of the proposed plan as filed include:

- Continuing a base distribution rate freeze through May 31, 2019;
- Continuing collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs;
- Providing economic development and assistance to low-income customers for the three-year plan period;
- An Economic Stability Program providing for a retail rate stability rider to flow through charges or credits representing the net result of the costs paid to FES through a proposed 15-year purchase power agreement for the output of Sammis, Davis-Besse and FES’ share of OVEC against the revenues received from selling the output into the PJM markets over the same period;
- Continuing to provide power to non-shopping customers at a market-based price set through an auction process;

- Continuing Rider DCR with increased revenue caps of approximately $30 million per year that allows continued investment supporting the distribution system for the benefit of customers;
- A commitment not to recover from retail customers certain costs related to transmission cost allocations for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of such costs avoided by customers for certain types of products totals $360 million, including appropriately such costs from MISO along with such costs from PJM, subject to the outcome of certain FERC proceedings; and
- General updates to electric service regulations and tariffs to reflect regulatory orders, administrative rule changes, and current practices.

On September 18, 2015, PUCO Staff filed testimony addressing various issues within the Ohio Companies' filing, including a recommendation that the PUCO deny the request for approval of a retail rate stability rider as proposed by the Ohio Companies, but PUCO Staff also stated that the retail rate stability rider may be in the public interest if its recommended changes are adopted. Briefs are due November 30, 2015, and reply briefs are due December 22, 2015. A final decision of the PUCO is expected early in 2016.

Under Ohio's energy efficiency standards (SB221 and SB310), and based on the Ohio Companies' amended energy efficiency plans, the Ohio Companies are required to implement energy efficiency programs that achieve a total annual energy savings equivalent of 2,266 GWHs in 2015 and 2,288 GWHs in 2016, and then begin to increase by 1% each year in 2017, subject to the outcome of a legislative study committee. The Ohio Companies are also required to retain the 2014 peak demand reduction level for 2015 and 2016 and then increase the benchmark by an additional 0.75% thereafter through 2020, subject to the outcome of a legislative study committee. On September 30, 2015, the Energy Mandates Study Committee issued its report related to energy efficiency and renewable energy mandates, recommending that the current level of mandates remain in place indefinitely. The report also recommended: (i) an expedited process for review of utility proposed energy efficiency plans; (ii) ensuring maximum credit for all of Ohio's Energy Initiatives; (iii) a switch from energy mandates to energy incentives; and (iv) a declaration be made that the General Assembly may determine energy policy of the state.

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

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

Ohio law requires electric utilities and electric service companies in Ohio to serve part of their load from renewable energy resources measured by an annually increasing percentage amount through 2026, subject to the outcome of a legislative study committee, except 2015 and 2016 that remain at the 2014 level. The Ohio Companies conducted RFPs in 2009, 2010 and 2011 to secure RECs to help meet these renewable energy requirements. In September 2011, the PUCO opened a docket to review the Ohio Companies' alternative energy recovery rider through which the Ohio Companies recover the costs of acquiring these RECs. The PUCO issued an Opinion and Order on August 7, 2013 approving the Ohio Companies' acquisition process and their purchases of RECs to meet statutory mandates in all instances except for part of the purchases arising from one auction and directing the Ohio Companies to credit non-shopping customers in the amount of $43.4 million, plus interest, on the basis that the Ohio Companies did not prove such purchases were prudent. On December 24, 2013, following the denial of their application for rehearing, the Ohio Companies filed a notice of appeal and a motion for stay of the PUCO's order with the Supreme Court of Ohio, which was granted. On February 18, 2014, the OCC and the ELPC also filed appeals of the PUCO's order. The Ohio Companies timely filed their merit brief with the Supreme Court of Ohio and the briefing process has concluded. The matter is not yet scheduled for oral argument.

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

PENNSYLVANIA

The Pennsylvania Companies currently operate under DSPs that expire on May 31, 2017, 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 spot market purchases, quarterly descending clock auctions for 3, 12- and 24-month energy contracts, and one RFP seeking 2-year contracts to serve SRECs for ME, PN, and Penn.

Pursuant to Pennsylvania's EE&C legislation (Act 129 of 2008) and PPUC orders, Pennsylvania EDC's implement energy efficiency and peak demand reduction programs. The Pennsylvania Companies' Phase II EE&C Plans are effective through May 31, 2016. Total costs of these plans are expected to be approximately $234 million and recoverable through the Pennsylvania Companies' reconcilable EE&C riders. On June 19, 2015, the PPUC issued a Phase III Final Implementation Order setting: demand reduction targets, relative to each Pennsylvania Companies' 2007-2008 peak demand (in MW), at 1.8% for ME, 1.7% for Penn, 1.8% for WP, and 0% for PN; and energy consumption reduction targets, as a percentage of each Pennsylvania Companies’ historic 2010 forecasts (in MWH), at 4.0% for ME, 3.9% for PN, 3.3% for Penn, and 2.6% for WP. The Pennsylvania Companies expect to file their Phase III EE&C plans for the June 2016 through May 2021 period by November 30, 2015. EDCs are permitted to recover costs for implementing Phase III EE&C plans.

Pursuant to Act 11 of 2012, Pennsylvania EDCs may establish a DSIC to recover costs of infrastructure improvements and costs related to highway relocation projects with PPUC approval. Pennsylvania EDCs must file LTIIPs outlining infrastructure improvement plans for PPUC review and approval prior to approval of a DSIC. On October 19, 2015, each of the Pennsylvania Companies filed LTIIPs with the PPUC for infrastructure improvement over the five-year period of 2016 to 2020 for the following costs: WP $88.34 million; PN $56.74 million; Penn $56.35 million; and ME $43.44 million. These amounts include all qualifying distribution capital additions identified in the revised implementation plan for the recent focused management and operations audit of the Pennsylvania

Companies. Following PPUC approval of the LTIIPs, the Pennsylvania Companies will submit DSIC tariffs for approval for quarterly recovery of approved costs.

Each of the Pennsylvania Companies currently offer distribution rates under their respective Joint Petitions for Settlement approved on April 9, 2015 by the PPUC, which, among other things, provide for a total increase in annual revenues for all Pennsylvania Companies of $292.8 million, ($89.3 million for ME, $90.8 million for PN, $15.9 million for Penn and $96.8 million for WP), including the recovery of $87.7 million of additional annual operating expenses, including costs associated with service reliability enhancements to the distribution system, amortization of deferred storm costs and the remaining net book value of legacy meters, assistance for providing service to low-income customers, and the creation of a storm reserve for each utility. Additionally, the settlements include commitments to meet certain wait times for call centers and service reliability standards. The new rates were effective May 3, 2015.

On July 16, 2013, the PPUC's Bureau of Audits initiated a focused management and operations audit of the Pennsylvania Companies as required every eight years by statute. The PPUC issued a report on its findings and recommendations on February 12, 2015, at which time the Pennsylvania Companies' associated implementation plan was also made public. In an order issued on March 30, 2015, the Pennsylvania Companies were directed to develop and file by May 29, 2015 revised implementation plans regarding certain of the operational topics addressed in the report, including addressing certain reliability matters. On May 19, 2015, the PPUC granted a forty-five day extension for the filing of revised implementation plans with respect to certain of the matters raised in its March 30, 2015 Order. On May 29, 2015 and July 13, 2015, the Pennsylvania Companies filed their revised implementation plan. On August 20, 2015, the PPUC issued a Tentative Order accepting the Pennsylvania Companies’ revised plan as being in the public interest and seeking public comment. The OCA submitted comments on September 21, 2015, generally supportive of the Pennsylvania Companies’ revised plan as being complementary with the commitments made in the recent base rate case proceedings. The Pennsylvania Companies filed a limited reply on October 13, 2015, and a Final Order is pending. The cost of compliance for the Pennsylvania Companies is currently expected to range from approximately $200 million to $230 million.

On June 19, 2015, ME and PN, along with JCP&L, FET and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT, a new transmission-only subsidiary of FET. Evidentiary hearings are scheduled to commence before the PPUC on February 29, 2016. A final decision from the PPUC is expected by mid-2016. See Transfer of Transmission Assets to MAIT in FERC Matters below for further discussion of this transaction.

WEST VIRGINIA

MP and PE currently operate under a Joint Stipulation and Agreement of Settlement approved by the WVPSC on February 3, 2015, that provides for: a $15 million increase in base rate revenues effective February 25, 2015; the implementation of a Vegetation Management Surcharge to recover all costs related to both new and existing vegetation maintenance programs; authority to establish a regulatory asset for MATS investments placed into service in 2016 and 2017; authority to defer, amortize and recover over a 5-year period approximately $46 million of storm restoration costs; and elimination of the TTS for costs associated with MP's acquisition of the Harrison plant in October 2013 and movement of those costs into base rates. MP and PE's current ENEC rates went into effect on February 25, 2015, in accordance with a settlement approved by the WVPSC on January 29, 2015.

On August 14, 2015, MP and PE filed their annual ENEC case with the WVPSC proposing an approximate $165.1 million annual increase in rates effective January 1, 2016 or before, which is a 12.5% overall increase over existing rates and remains subject to WVPSC approval. The proposed increase is comprised of a $97 million under-recovered balance as of June 30, 2015, a projected $23.7 million under-recovery for the 2016 calendar year, and an actual under-recovered balance from MP and PE's TTS for Harrison Power Station of $44.4 million. On September 10, 2015, MP and PE filed an amendment addressing the results of the recent PJM Transitional Auctions for Capacity Performance, which resulted in a net decrease of $20.6 million from the initial requested increase to $144.5 million. A hearing has been set for November 19-20, 2015 with an order expected to be issued before the end of 2015 for rates effective by January 1, 2016.

On August 31, 2015, MP and PE filed with the WVPSC their biennial petition for reconciliation of the Vegetation Management Program Surcharge and regular review of the program proposing an approximate $37.7 million annual increase in rates, which is a 2.8% overall increase over existing rates and remains subject to WVPSC approval. The proposed increase is comprised of a $2.1 million under-recovered balance as of June 30, 2015, a projected $23.9 million in under-recovery for the 2016/2017 rate effective period, and recovery of previously authorized deferred vegetation management costs from April 14, 2014 through February 24, 2015 in the amount of $49.9 million. Hearings are scheduled for November 19-20, 2015 and a final order is expected to be issued before the end of 2015 for rates effective by January 1, 2016.

RELIABILITY MATTERS

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

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

FERC MATTERS

PJM Transmission Rates

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

The PJM transmission owners, including FirstEnergy, submitted filings to FERC setting forth the cost allocation method under Order No. 1000 for projects that cross the borders between the PJM Region and: (i) the NYISO region; (ii) the MISO region; and (iii) the FERC-jurisdictional members of the SERTP region. These filings propose to allocate the costs of these interregional transmission projects based on the costs of projects that otherwise would have been constructed separately in each region, or, in the case of MISO, based on 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. As of May 14, 2015, FERC has accepted the PJM/NYISO, PJM/MISO and PJM/SERTP filings, subject to further compliance requirements. FERC’s acceptance of the PJM/SERTP filing is also subject to refund and the SERTP region participants’ related Order No. 1000 interregional compliance proceedings.

In a series of orders in certain Order No. 1000 dockets, FERC 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 the question of whether FirstEnergy and the PJM transmission owners have a "right of first refusal" is now pending before the U.S. Court of Appeals for the D.C. Circuit in an appeal of FERC's order approving PJM's Order No.1000 compliance filing.

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

RTO Realignment

On June 1, 2011, ATSI and the ATSI zone transferred from MISO to PJM. While many of the matters involved with the move have been resolved, FERC denied recovery under ATSI's transmission rate for certain charges that collectively can be described as "exit fees" and certain other transmission cost allocation charges totaling approximately $78.8 million until such time as ATSI submits a cost/benefit analysis demonstrating net benefits to customers from the move. Subsequently, FERC rejected a proposed settlement agreement to resolve the exit fee and transmission cost allocation issues, stating that its action is without prejudice to ATSI submitting a cost/benefit analysis demonstrating that the benefits of the RTO realignment decisions outweigh the exit fee and transmission cost allocation charges. FirstEnergy's request for rehearing of FERC's order rejecting the settlement agreement 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 United States appellate courts. In the event of a final non-appealable order that rules that ATSI must pay these charges, ATSI will seek recovery of these charges through its formula rate. On a related issue, FirstEnergy joined certain other PJM transmission owners in a protest of MISO's proposal to allocate MVP costs to energy transactions that cross MISO's borders into the PJM Region. On January 22, 2015, FERC issued an order establishing a paper hearing on remand from the Seventh Circuit of the issue of whether any limitation on "export pricing" for sales of energy from MISO into PJM is justified in light of applicable FERC precedent. On April 22, 2015, certain PJM transmission owners, including FirstEnergy, filed an initial brief asserting that FERC’s prior ruling rejecting MISO’s proposed MVP export charge on transactions into PJM was correct and should be re-affirmed on remand. Reply comments were filed June 22, 2015. The matter is now before FERC for consideration.

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

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

2014 ATSI Formula Rate Filing

On October 31, 2014, ATSI filed a proposal with FERC to change the structure of its formula rate. The proposed change requested to move from an “historical looking” approach, where transmission rates reflect actual costs for the prior year, to a “forward looking” approach, where transmission rates would be based on the estimated costs for the coming year, with an annual true up. On December 31, 2014, FERC issued an order accepting ATSI's filing effective January 1, 2015, as requested, subject to refund and the outcome of hearing and settlement proceedings. FERC also initiated an inquiry pursuant to Section 206 of the FPA into ATSI's ROE and certain other matters, with a refund effective date of January 12, 2015, for any refund resulting from the inquiry. On July 20, 2015, ATSI and certain parties filed a settlement agreement with FERC, which remains subject to FERC approval. The agreement provides for certain changes to ATSI's proposed forward-looking formula rate template and protocols, and also changes ATSI's ROE from 12.38% to the following values: (i) 12.38% for the period commencing January 1, 2015 through June 30, 2015; (ii) 11.06% for the period commencing July 1, 2015 through December 31, 2015; and (iii) 10.38% for the period commencing January 1, 2016. The 10.38% ROE value will remain in effect unless changed pursuant to section 205 or 206 of the FPA provided the effective date for any change cannot be earlier than January 1, 2018. The agreement currently is pending at FERC and ATSI anticipates that it will be approved later this year.

Transfer of Transmission Assets to MAIT

On June 10, 2015, MAIT, a Delaware limited liability company, was formed as a new transmission-only subsidiary of FET for the purposes of owning and operating all FERC-jurisdictional transmission assets of JCP&L, ME and PN following the receipt of all necessary state and federal regulatory approvals. On June 19, 2015, JCP&L, PN, ME, FET, and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT. Additionally, the filings requested approval from the NJBPU and PPUC, as applicable, of; (i) a lease to MAIT of real property and rights-of-way associated with the utilities' transmission assets; (ii) a Mutual Assistance Agreement; (iii) MAIT being deemed a public utility under state laws; (iv) MAIT's participation in FE's regulated companies' money pool; and (v) certain affiliated interest agreements. If approved, JCP&L, ME, and PN will contribute their transmission assets at net book value and an allocated portion of goodwill in a tax-free exchange to MAIT, which will operate similar to FET's two existing stand-alone transmission subsidiaries, ATSI and TrAIL. MAIT's transmission facilities will remain under the functional control of PJM, and PJM will provide transmission service using these facilities under the PJM Tariff. During the third quarter of 2015, FirstEnergy responded to FERC Staff's request for additional information regarding the application. FERC approval is expected in early-2016 with final decisions expected from the NJBPU and PPUC by mid-2016. Following FERC approval of the transfer, MAIT expects to file a Section 204 application with FERC, and other necessary filings with the PPUC and the NJBPU, seeking authorization to issue equity to FET, JCP&L, PN and ME for their respective asset contributions, and to issue debt. MAIT will also make a Section 205 formula rate application with FERC to establish its transmission rate.

California Claims Matters

In October 2006, several California governmental and utility parties presented AE Supply with a settlement proposal to resolve alleged overcharges for power sales by AE Supply to the California Energy Resource Scheduling division of the CDWR during 2001. The settlement proposal claims that CDWR is owed approximately $190 million for these alleged overcharges. This proposal was made in the context of mediation efforts by FERC and the Ninth Circuit in several pending proceedings to resolve all outstanding refund and other claims, including claims of alleged price manipulation in the California energy markets during 2000 and 2001. The Ninth Circuit had previously remanded one of those proceedings to FERC, which dismissed the claims of the California Parties in May 2011. The California Parties appealed FERC's decision back to the Ninth Circuit. AE Supply joined with other intervenors in the case and filed a brief in support of FERC's dismissal of the case. On April 29, 2015, the Ninth Circuit issued a decision remanding the case to FERC for further proceedings.

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

FirstEnergy cannot predict the outcome of either of the above matters or estimate the possible loss or range of loss.

PATH Transmission Project

On August 24, 2012, the PJM Board of Managers canceled the PATH project, a proposed transmission line from West Virginia through Virginia and into Maryland which PJM had previously suspended in February 2011. As a result of PJM canceling the project, approximately $62 million and approximately $59 million in costs incurred by PATH-Allegheny and PATH-WV (an equity method investment for FE), respectively, were reclassified from net property, plant and equipment to a regulatory asset for future recovery. PATH-Allegheny and PATH-WV requested authorization from FERC to recover the costs with a proposed ROE of 10.9% (10.4% base plus 0.5% for RTO membership) from PJM customers over five years. FERC issued an order denying the 0.5% ROE adder for RTO membership and allowing the tariff changes enabling recovery of these costs to become effective on December 1, 2012, subject to settlement proceedings and hearing if the parties could not agree to a settlement. On March 24, 2014, the FERC Chief ALJ terminated settlement proceedings and appointed an ALJ to preside over the hearing phase of the case, including discovery and additional pleadings leading up to hearing, which subsequently included the parties addressing the application of FERC's Opinion No. 531, discussed below, to the PATH proceeding. The hearing concluded on April 22, 2015. On September 14, 2015, the ALJ issued his initial decision, disallowing recovery of certain costs (primarily relating to advertising and losses on real property) and finding that PATH’s ROE for the five-year recovery period should be set at 6.27%. The proceedings have now moved to the exception phase with briefs on exceptions filed on October 14, 2015, and briefs opposing exceptions due November 3, 2015. The initial decision and exception briefs will then be before FERC for review and a final order. FirstEnergy continues to believe the costs are recoverable, subject to final ruling from FERC.

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 the potential for 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 forecast based on a forecast for the U.S. economy (1/3 weight). Regarding the qualitative adjustment, for single-utility rate cases FERC formerly pegged ROE at the median 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. On October 16, 2014, FERC issued its Opinion No. 531-A, applying the revised ROE methodology to certain ISO New England transmission owners. On March 3, 2015, FERC issued Opinion No. 531-B affirming its prior rulings. Appeals of Opinion Nos. 531, 532-A and 531-B are pending before the U.S. Court of Appeals for the D.C. Circuit. 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.

MISO Capacity Portability

On June 11, 2012, in response to certain arguments advanced by MISO, FERC issued a Notice of Request for Comments regarding whether existing rules on transfer capability act as barriers to the delivery of capacity between MISO and PJM. FirstEnergy and other parties have submitted filings arguing that MISO's concerns largely are without foundation and suggested that FERC address the remaining concerns in the existing stakeholder process that is described in the PJM/MISO Joint Operating Agreement. FERC has not mandated a solution, and the RTOs and affected parties are working to address the MISO's proposal in stakeholder proceedings. In January 2015, the RTOs and affected parties indicated to FERC that discussions on the various issues are continuing. At FERC's direction, on May 12 and 13, 2015, PJM, MISO, and their respective independent market monitors provided additional information on their various joint issues surrounding the PJM/MISO seam, including capacity portability, to assist the FERC's understanding of the issues and what, if any, additional steps FERC should take to improve the efficiency of operations at the PJM/MISO seam. Stakeholders, including FESC on behalf of certain of its affiliates and as part of a coalition of certain other PJM utilities, filed responses to the RTO submissions. The various submissions and responses are now before FERC for consideration.

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.

Synchronous Condensers

On December 20, 2012, FERC approved the transfer by FG to ATSI of certain deactivated generation assets associated with Eastlake Units 1 through 5 to facilitate their conversion to synchronous condensers to provide voltage support on the ATSI transmission system. The transfer of Eastlake Units 4-5 was completed on January 31, 2013, and the transfer of Eastlake Units 1-3 was completed on April 30, 2015.

FTR Underfunding Complaint

In PJM, FTRs are a mechanism to hedge congestion and operate as a financial replacement for physical firm transmission service. FTRs are financially-settled instruments that entitle the holder to a stream of revenues based on the hourly congestion price differences across a specific transmission path in the PJM Day-ahead Energy Market. FE also performs bilateral transactions for the purpose of hedging the price differences between the location of supply resources and retail load obligations. Due to certain language in the PJM Tariff, the funds that are set aside to pay FTRs can be diverted to other uses, which may result in “underfunding” of FTR payments. FES and AE Supply continue to evaluate proposals to address issues with FTR allocation and funding.

On February 15, 2013, FES and AE Supply filed a renewed complaint with FERC for the purpose of changing the PJM Tariff to eliminate FTR underfunding. On June 5, 2013, FERC issued an order denying the new complaint and on June 8, 2015, denied a request for rehearing of the June 5, 2013 order.

A recent and related issue is the effect that certain financial trades have on congestion. On August 29, 2014, FERC instituted an investigation to address the question of whether the current rules regarding “Up-to Congestion” transactions are just and reasonable. FESC, on behalf of FES and the Utilities, filed comments supporting the investigation, arguing that PJM Tariff changes would decrease the incidence of Up-to Congestion transactions, and funding for FTRs likely would increase. FERC convened a technical conference on January 7, 2015 to discuss application of certain FTR-related rules to Up-to Congestion. On October 19, 2015, PJM submitted two filings to further adjust its FTR tariffs. Comments are due on November 9, 2015. FE is evaluating PJM's filings.

PJM Market Reform: 2014 PJM RPM Tariff Amendments

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

PJM Market Reform: PJM Capacity Performance Proposal

In December 2014, PJM submitted proposed “Capacity Performance” reforms of its RPM capacity and energy markets. On June 9, 2015, FERC issued an order conditionally approving the bulk of the proposed Capacity Performance reforms with an effective date of April 1, 2015, and directed PJM to make a compliance filing reflecting the mandate of FERC’s order. On July 9, 2015, several parties, including FESC on behalf of certain of its affiliates, submitted requests for rehearing for FERC's June 9, 2015 order, and PJM submitted its compliance filing as directed by the order. The requests for rehearing and PJM's compliance filing are pending before FERC.
Following FERC's issuance of the June 9, 2015 order on the Capacity Performance proposal, PJM conducted the 2015 BRA for the 2018/2019 delivery year on August 10-14, 2015, and reported a clearing price for Capacity Performance of $164.77/MW-day and a clearing price for base capacity of $149.98/MW-day in the Rest-of-RTO and ATSI regions.

PJM conducted the Capacity Performance transition auction for the 2016/2017 delivery year on August 26-27, 2015, and reported an RTO-wide clearing price of $134.00/MW-day. PJM conducted the Capacity Performance transition auction for the 2017/2018 delivery year on September 3-4, 2015, and reported an RTO-wide clearing price of $151.50/MW-day. FirstEnergy's net competitive capacity position as a result of the BRA and Capacity Performance transition auctions is as follows:

	2016 - 2017				2017 - 2018				2018 - 2019*			
	Legacy Obligation		Capacity Performance		Legacy Obligation		Capacity Performance		Base Generation		Capacity Performance	
	(MW)	($/MWD)	(MW)	($/MWD)	(MW)	($/MWD)	(MW)	($/MWD)	(MW)	($/MWD)	(MW)	($/MWD)
ATSI	2,765	$114.23	4,210	$134.00	375	$120.00	6,245	$151.50	—	$149.98	6,245	$164.77
RTO	875	$59.37	3,675	$134.00	985	$120.00	3,565	$151.50	240	$149.98	3,930	$164.77
All Other Zones	135	$119.13	—	$134.00	150	$120.00	—	$151.50	35	**	20	**
	3,775		7,885		1,510		9,810		275		10,195	

*Approximately 885 MWs remain uncommitted for the 2018/2019 delivery year.
**Base Generation: 10 MWs cleared at $200.21/MWD and 25 MWs cleared at $149.98/MWD. Capacity Performance: 5 MWs cleared at $215.00/MWD and 15 MWs cleared at $164.77/MWD.

FirstEnergy and other PJM market entities also are addressing PJM’s capacity market concerns in other FERC proceedings. On November 20, 2014, FERC issued an order directing each ISO/RTO to file a report with FERC outlining each region’s efforts to ensure fuel security. PJM filed its report on February 18, 2015, advising FERC that PJM’s Capacity Performance proposal would address fuel assurance issues. On March 20, 2015, FESC, on behalf of its affected affiliates and as part of a coalition, filed responsive comments demonstrating that significant improvements were needed for PJM’s Capacity Performance proposal to address fuel assurance issues. The comments are before FERC for review.

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

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

PJM Market Reform: FERC Order No. 745 - DR

On May 23, 2014, a divided three-judge panel of the U.S. Court of Appeals for the D.C. Circuit issued an opinion vacating FERC Order No. 745, which required that, under certain parameters, DR participating in organized wholesale energy markets be compensated at LMP. The majority concluded that DR is a retail service, and therefore falls under state, and not federal, jurisdiction, and that FERC, therefore, lacks jurisdiction to regulate DR. The majority also found that even if FERC had jurisdiction over DR, Order No. 745 would be arbitrary and capricious because, under its requirements, DR was inappropriately receiving a double payment (LMP plus the savings of foregone energy purchases). On May 4, 2015, the United States Supreme Court granted petitions for certiorari requesting review of the May 23, 2014 opinion, and heard oral argument on the issues on October 14, 2015. The U.S. Court of Appeals for the D.C. Circuit is withholding issuance of its mandate pending the United States Supreme Court's review on the merits.

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

PJM Market Reform: PJM 2014 Triennial RPM Review

The PJM Tariff obligates PJM to perform a thorough review of its RPM program every three years. On September 25, 2014, PJM filed proposed changes to the PJM Tariff as part of the latest review cycle. Among other adjustments, the filing included: (i) shifting the VRR curve one percentage point to the right, which would increase the amount of capacity supply that is procured in the RPM auctions and the clearing price; and (ii) a change to the index used for calculating the generation plant construction costs of the Net CONE formula for the future years between triennial reviews. On November 28, 2014, FERC accepted the PJM Tariff amendments as proposed, subject to a minor compliance requirement. PJM subsequently submitted the required compliance filing. On December 23, 2014, a coalition including FESC, on behalf of its affected affiliates, requested rehearing of FERC's order. On October 15, 2015, FERC issued an order denying rehearing and accepting PJM's compliance filing.

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.

CSAPR requires reductions of NOx and SO_2 emissions in two phases (2015 and 2017), 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 July 28, 2015, the U.S. Court of Appeals for the D.C. Circuit ordered the EPA to reconsider caps on NOx and SO_2 emissions from power plants in 13 states, including Ohio, Pennsylvania and West Virginia. This follows the 2014 U.S. Supreme Court ruling generally upholding EPA’s regulatory approach under the CSAPR, but questioning whether EPA required upwind states to reduce emissions by more than their contribution to air pollution in downwind states. Depending on how the EPA and the states implement the CSAPR, the future cost of compliance may be substantial and changes to FirstEnergy's and FES' operations may result.

EPA tightened the primary and secondary NAAQS for ozone from the 2008 standard levels of 75 PPB to 70 PPB on October 1, 2015. EPA stated the vast majority of U.S. counties will meet the new 70 PPB standard by 2025 due to other federal and state rules and programs but will designate counties that fail to attain the new 2015 ozone NAAQS by October 1, 2017. States will then have roughly three years to develop implementation plans to attain the new 2015 ozone NAAQS. Depending on how the EPA and the states implement the new 2015 ozone NAAQS, the future cost of compliance may be substantial and changes to FirstEnergy’s and FES’ operations may result.

MATS imposes emission limits for mercury, PM, and HCL for all existing and new fossil fuel 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 plants. 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 plants. On February 5, 2015, the OEPA granted an extension through April 16, 2016 for MATS compliance at the Bay Shore and Sammis plants. Nearly all spending for MATS compliance at Bay Shore and Sammis has been completed through 2014. In addition, an EPA enforcement policy document contemplates up to an additional year to achieve compliance, through April 2017, under certain circumstances for reliability critical units. On June 29, 2015, the United States Supreme Court reversed a U.S. Court of Appeals for the D.C. Circuit decision that upheld MATS, rejecting EPA’s regulatory approach that costs are not relevant to the decision of whether or not to regulate power plant emissions under Section 112 of the Clean Air Act and remanded the case back to the U.S. Court of Appeals for the D.C. Circuit for further proceedings. Subject to the outcome of further proceedings before the U.S. Court of Appeals for the D.C. Circuit and how the MATS are ultimately implemented, FirstEnergy's total capital cost for compliance (over the 2012 to 2018 time period) is currently expected to be approximately $370 million (CES segment of $178 million and Regulated Distribution segment of $192 million), of which $176 million has been spent through September 30, 2015 ($66 million at CES and $110 million at Regulated Distribution).

Eastlake Units 1-3, Ashtabula Unit 5 and Lake Shore Unit 18 were deactivated in April 2015, which completes the deactivation of 5,429 MW of coal-fired plants since 2012.

On August 3, 2015, FG, a subsidiary of FES, submitted to the AAA office in New York, N.Y., a demand for arbitration and statement of claim against BNSF and CSX seeking a declaration that MATS constituted a force majeure that excuses FG’s performance under its coal transportation contract with these parties. Specifically, the dispute arises from a contract for the transportation by BNSF and CSX of a minimum of 3.5 million tons of coal annually through 2025 to certain coal-fired power plants owned by FG that are located in Ohio. As a result of and in compliance with MATS, those plants were deactivated by April 16, 2015. In January 2012, FG notified BNSF and CSX that MATS constituted a force majeure event under the contract that excused FG’s further performance. Separately, on August 4, 2015, BNSF and CSX submitted to the AAA office in Washington, D.C., a demand for arbitration and statement of claim against FG alleging that FG breached the contract and that FG’s declaration of a force majeure under the contract is not valid and seeking damages including, but not limited to, lost profits under the contract through 2025. As part of its statement of claim, a right to liquidated damages is alleged. FirstEnergy and FES continue to believe that MATS constitutes a force majeure event under the contract as it relates to the deactivated plants and that FG’s performance under the contract is therefore excused. FirstEnergy and FES intend to vigorously assert their position in the arbitration proceedings. If, however, the arbitration panel rules in favor of BNSF and CSX, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. FirstEnergy and FES are unable to estimate the loss or range of loss.

FG is also a party to another coal transportation contract covering the delivery of 2.5 million tons annually through 2025, a portion of which is to be delivered to another coal-fired plant owned by FG that was deactivated as a result of MATS. FG has asserted a defense of force majeure in response to delivery shortfalls to such plant under this contract as well. If FirstEnergy and FES fail to reach a resolution with the applicable counterparties to the contract, and if it were ultimately determined that, contrary to FirstEnergy's and FES' belief, the force majeure provisions of that contract do not excuse the delivery shortfalls, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. FirstEnergy and FES are unable to estimate the loss or range of loss.

As to both coal transportation agreements referenced above, FES paid in settlement approximately $70 million in liquidated damages for delivery shortfalls in 2014 related to its deactivated plants.

As to a specific coal supply agreement, FirstEnergy and AE Supply have asserted termination rights effective in 2015. In response to notification of the termination, the coal supplier commenced litigation alleging FirstEnergy and AE Supply do not have sufficient justification to terminate the agreement. FirstEnergy and AE Supply have filed an answer denying any liability related to the termination. There are 6 million tons remaining under the contract for delivery. At this time, FirstEnergy cannot estimate the loss or range of loss regarding the on-going litigation with respect to this agreement.

In September 2007, AE received an NOV from the EPA alleging NSR and PSD violations under the CAA, as well as Pennsylvania and West Virginia state laws at the coal-fired Hatfield's Ferry and Armstrong plants in Pennsylvania and the coal-fired Fort Martin and Willow Island plants in West Virginia. The EPA's NOV alleges equipment replacements during maintenance outages triggered the pre-construction permitting requirements under the NSR and PSD programs. On June 29, 2012, January 31, 2013, and March 27, 2013, EPA issued CAA section 114 requests for the Harrison coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2007. On December 12, 2014, EPA issued a CAA section 114 request for the Fort Martin coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2009. FirstEnergy intends to comply with the CAA but, at this time, is unable to predict the outcome of this matter or estimate the possible loss or range of loss.

Climate Change

There are a number of initiatives to reduce GHG emissions at the state, federal and international level. Certain northeastern states are participating in the RGGI and western states led by California, have implemented programs, primarily cap and trade mechanisms, to control emissions of certain GHGs. Additional policies reducing GHG emissions, such as demand reduction programs, renewable portfolio standards and renewable subsidies have been implemented across the nation. A June 2013, Presidential Climate Action Plan outlined goals to: (i) cut carbon pollution in America by 17% by 2020 (from 2005 levels); (ii) prepare the United States for the impacts of climate change; and (iii) 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.

The EPA released its final "Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act" in December 2009, concluding that concentrations of several key GHGs constitutes an "endangerment" and may be regulated as "air pollutants" under the CAA and mandated measurement and reporting of GHG emissions from certain sources, including electric generating plants. The EPA released its final regulations in August 2015, to reduce CO_2 emissions from existing fossil fuel fired electric generating units that would require each state to develop SIPs by September 6, 2016, to meet the EPA's state specific CO_2 emission rate goals. The EPA's CPP allows states to request a 2-year extension to finalize SIPs by September 6, 2018. If states fail to develop SIPs, the EPA also proposed a federal implementation plan that can be implemented by the EPA that included model emissions trading rules which states can also adopt in their SIPs. The EPA also finalized separate regulations imposing CO_2 emission limits for new, modified, and reconstructed fossil fuel fired electric generating units. On June 23, 2014, the United States Supreme Court decided that CO_2 or other GHG emissions alone cannot trigger permitting requirements under the CAA, but that air emission sources that need PSD permits due to other regulated air pollutants can be required by the EPA to install GHG control technologies. On June 9, 2015, the U.S. Court of Appeals for the D.C. Circuit denied challenges to prevent the EPA from regulating CO_2 emissions from existing fossil fuel fired electric generating units because the EPA's proposed Clean Power Plant is not final agency action and therefore not ripe for review. Depending on the outcome of further appeals and how any final rules are ultimately implemented, the future cost of compliance may be substantial.

At the international level, the United Nations Framework Convention on Climate Change resulted in the Kyoto Protocol requiring participating countries, which does not include the U.S., to reduce GHGs commencing in 2008 and has been extended through 2020. In advance of the December 2015 United Nations Framework Convention on Climate Change meetings in Paris, the Obama Administration submitted in March 2015, a formal pledge for the U.S. to reduce its economy-wide greenhouse gas emissions by 26 to 28 percent below 2005 levels by 2025. FirstEnergy cannot currently estimate the financial impact of climate change policies, although potential legislative or regulatory programs restricting CO_2 emissions, or litigation alleging damages from GHG emissions, could require significant capital and other expenditures or result in changes to its operations. The CO_2 emissions per KWH of electricity generated by FirstEnergy is lower than many of its regional competitors due to its diversified generation sources, which include low or non-CO_2 emitting gas-fired and nuclear generators.

Clean Water Act

Various water quality regulations, the majority of which are the result of the federal CWA and its amendments, apply to FirstEnergy's plants. In addition, the states in which FirstEnergy operates have water quality standards applicable to FirstEnergy's operations.

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

The EPA proposed updates to the waste water effluent limitations guidelines and standards for the Steam Electric Power Generating category (40 CFR Part 423) in April 2013. On September 30, 2015, the EPA finalized new, more stringent effluent limits for arsenic, mercury, selenium and nitrogen for wastewater from wet scrubber systems and zero discharge of pollutants in ash transport water. The final rule also allows plants to commit to more stringent effluent limits for wet scrubber systems based on evaporative technology and in return have until the end of 2023 to meet the more stringent limits. The treatment obligations will phase-in as permits are renewed on a five-year cycle from 2018 to 2023. Depending on the outcome of appeals and how any final rules are ultimately implemented, the future costs of compliance with these standards may be substantial and changes to FirstEnergy's and FES' operations may result.

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 the appeal or estimate the possible loss or range of loss.

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

Regulation of Waste Disposal

Federal and state hazardous waste regulations have been promulgated as a result of the RCRA, as amended, and the Toxic Substances Control Act. Certain coal combustion residuals, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation.

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

The PA DEP filed a 2012 complaint against FG in the United States District Court for the Western District of Pennsylvania with claims under the RCRA and Pennsylvania's Solid Waste Management Act regarding the LBR CCR Impoundment and simultaneously proposed a consent decree between PA DEP and FG to resolve those claims. On December 14, 2012, a modified consent decree was entered by the court, requiring FG to conduct monitoring studies and submit a closure plan to the PA DEP, no later than March 31, 2013, and discontinue disposal to LBR as currently permitted by December 31, 2016. The modified consent decree also required payment of civil penalties of $800,000 to resolve claims under the Solid Waste Management Act. PA DEP issued a 2014 permit requiring FE to provide bonding for 45 years of closure and post-closure activities and to complete closure within a 12-year period, but authorizing FE to seek a permit modification based on "unexpected site conditions that have or will slow closure progress." The permit does not require active dewatering of the CCRs, but does require a groundwater assessment for arsenic and abatement if certain conditions in the permit are met. The Bruce Mansfield plant is pursuing several options for its CCRs following December 31, 2016. A June 28, 2013 complaint filed by Citizens Coal Counsel and other NGOs in the United States District Court for the Western District of Pennsylvania, against the owner and operator of a reclamation mine in LaBelle, Pennsylvania that is one possible alternative, alleged the LaBelle site is in violation of RCRA and state laws. On July 14, 2014, Citizens Coal Council served FE, FG and NRG with a citizen suit notice alleging violations of RCRA due to beneficial reuse of "coal ash" at the LaBelle Site. To date, no complaint has been filed. On May 22, 2015 and September 21, 2015, the PA DEP reissued a permit for the Hatfield's Ferry CCR disposal facility and then modified that permit to allow disposal of Bruce Mansfield plant CCR. On July 6, 2015 and October 22, 2015, the Sierra Club filed Notice of Appeals with the Pennsylvania Environmental Hearing Board challenging the renewal, reissuance and modification of the permit for the Hatfield’s Ferry CCB disposal facility.

FirstEnergy or its subsidiaries have been named as potentially responsible parties at waste disposal sites, which may require cleanup under the CERCLA. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all potentially responsible parties for a particular site may be liable on a joint and several basis. Environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheets as of September 30, 2015 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 $148 million have been accrued through September 30, 2015. Included in the total are accrued liabilities of approximately $93 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, 2015, FirstEnergy had approximately $2.3 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. The values of FirstEnergy's NDTs fluctuate based on market conditions. If the value of the trusts decline by a material amount, FirstEnergy's obligation to fund the trusts may increase. Disruptions in the capital markets and their effects on particular businesses and the economy could also affect the values of the NDTs. FE and FES have also entered into a total of $24.5 million in parental guaranties in support of the decommissioning of the spent fuel storage facilities located at the nuclear facilities. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guaranties, as appropriate.

In August 2010, FENOC submitted an application to the NRC for renewal of the Davis-Besse operating license for an additional twenty years, until 2037. An NRC ASLB granted an opportunity for a hearing on the Davis-Besse license renewal application to a group of Intervenors, subject to the admissibility of contentions. On March 10, 2015, the ASLB issued an Order that terminated its jurisdiction and closed the record in the Davis-Besse license renewal proceeding. On June 9, 2015, the NRC Commissioners denied an intervenor's filed requests to reopen the record and admit a contention on the NRC’s Continued Storage Rule. On August 6, 2015, this intervenor sought review of the NRC Commissioners' decision before the U.S. Court of Appeals for the DC Circuit. FENOC has moved to intervene in that proceeding.

As part of routine inspections of the concrete shield building at Davis-Besse in 2013, FENOC identified changes to the subsurface laminar cracking condition originally discovered in 2011. These inspections revealed that the cracking condition had propagated a small amount in select areas. FENOC's analysis confirms that the building continues to maintain its structural integrity, and its ability to safely perform all of its functions. In a May 28, 2015, Inspection Report regarding the apparent cause evaluation on crack propagation, the NRC issued a non-cited violation for FENOC’s failure to request and obtain a license amendment for its method of evaluating the significance of the shield building cracking. The NRC also concluded that the shield building remained capable of performing its design safety functions despite the identified laminar cracking and that this issue was of very low safety significance.

The NRC continues to evaluate FENOC's analysis of the shield building.

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

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 "Revenue from Contracts with Customers", requiring entities to recognize revenue by applying a five-step model in accordance with the core principle to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In addition, the accounting for costs to obtain or fulfill a contract with a customer is specified and disclosure requirements for revenue recognition are expanded. In August 2015, the FASB issued a final Accounting Standards Update deferring the effective date until fiscal years beginning after December 15, 2017. Earlier application is permitted only as of annual reporting periods beginning after December 15, 2016, (the original effective date). The standard 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.

In February 2015, the FASB issued, "Consolidations: Amendments to the Consolidation Analysis", which amends current consolidation guidance including changes to both the variable and voting interest models used by companies to evaluate whether an entity should be consolidated. This standard is effective for interim and annual periods beginning after December 15, 2015, and early adoption is permitted. A reporting entity must apply the amendments using a modified retrospective approach by recording a cumulative-effect adjustment to equity as of the beginning of the period of adoption or apply the amendments retrospectively. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

In April 2015, the FASB issued, "Simplifying the Presentation of Debt Issuance Costs", which requires debt issuance costs to be presented on the balance sheet as a direct deduction from the carrying value of the associated debt liability, consistent with the presentation of a debt discount. The guidance is effective for financial statements issued for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years. Upon adoption, an entity must apply the new guidance retrospectively to all prior periods presented in the financial statements. FirstEnergy does not expect this amendment to have a material effect on its financial statements.

In August 2015, the FASB issued ASU 2015-13, "Application of the NPNS Scope Exception to Certain Electricity Contracts within Nodal Energy Markets", which confirmed that forward physical contracts for the sale or purchase of electricity meet the physical delivery criterion within the NPNS scope exception when the electricity is transmitted through a grid managed by an ISO. As a result, an entity can elect the NPNS exception within the derivative accounting guidance for such contracts, provided that the other NPNS criteria are also met. The ASU was effective on issuance and requires prospective application. FirstEnergy does not expect this to have a material effect on its financial statements.

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 the uncommitted output of AE Supply, as well as the output relating to leasehold interests of OE and TE in certain of those facilities that are subject to sale and leaseback arrangements, and pursuant to full output, cost-of-service PSAs.

FES’ revenues are derived primarily from sales to individual retail customers, sales to customers in the form of governmental aggregation programs, and participation in affiliated and non-affiliated POLR auctions. FES’ sales are primarily concentrated in Ohio, Pennsylvania, Illinois, Michigan, New Jersey and Maryland. The demand for electricity produced and sold by FES, along with the price of that electricity, is principally impacted by conditions in competitive power markets, global economic activity as well as economic activity and weather conditions in the Midwest and Mid-Atlantic regions of the United States. In 2014, FES began reducing its exposure to weather-sensitive loads, 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, FES has eliminated future selling efforts in certain sales channels, such as Mass Market, medium commercial-industrial and select large commercial-industrial (Direct), to focus on a selective mix of retail sales channels, wholesale sales that hedge generation more effectively, and maintain a small open position to take advantage of market upside opportunities resulting from volatility as was experienced in the first quarter of 2014. In 2015 and going forward, FES expects to target approximately 65 to 75 million MWHs in annual contract sales with a projected target portfolio mix of approximately 10 to 15 million MWHs in Governmental Aggregation sales, 0 to 10 million MWHs of POLR sales, 0 to 20 million MWHs in large commercial and industrial sales (Direct),10 to 20 million MWHs in block wholesale sales, including Structured sales, and 10 to 20 million MWHs of spot wholesale sales. As of September 30, 2015, committed contract sales for calendar year 2015, 2016 and 2017 are 72 million MWHs, 59 million MWHs, and 36 million MWHs, respectively. Support for current customers in the channels to be exited will remain through their respective contract terms.

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

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

Results of Operations

Operating results increased $126 million in the first nine months of 2015, compared to the same period of 2014. In the first nine months of 2014, FES sold certain hydroelectric power stations resulting in an after-tax gain of $110 million. Excluding the impact of this gain and discontinued operations, year-over-year operating results improved $242 million primarily from higher capacity revenue associated with higher capacity auction prices and the absence of the extreme market conditions and unplanned outages in January 2014 resulting in higher costs to serve contract sales. Subsequent to the first quarter of 2014, FES began to reduce its exposure to weather-sensitive loads and more effectively hedge its generation. As a result of that revised strategy, FES was able to successfully mitigate the extreme weather conditions that occurred in February 2015 by more effectively using its generation to supply higher customer usage as compared to 2014 when FES purchased power at higher prices to supply increased customer usage.

Revenues -

Total revenues decreased $968 million, in the first nine months of 2015, compared to the same period of 2014, primarily due to decreased sales volumes in line with FES' strategy to more effectively hedge its generation. Revenues were also impacted by higher unit prices as a result of the change in sales channel mix and increased channel pricing as well as higher capacity revenues, as further described below.

The change in total revenues resulted from the following sources:

Revenues by Type of Service	Nine Months Ended September 30, 2015	2014	Increase (Decrease)
	(In millions)		
Contract Sales:			
Direct	$1,014	$1,876	$(862)
Governmental Aggregation	802	924	(122)
Mass Market	222	354	(132)
POLR	585	681	(96)
Structured Sales	410	358	52
Total Contract Sales	3,033	4,193	(1,160)
Wholesale	558	317	241
Transmission	102	168	(66)
Other	141	124	17
Total Revenues	$3,834	$4,802	$(968)

MWH Sales by Channel	Nine Months Ended September 30, 2015	2014	Increase (Decrease)
	(In thousands)		
Contract Sales:			
Direct	18,860	35,018	(46.1)%
Governmental Aggregation	12,278	15,413	(20.3)%
Mass Market	3,246	5,294	(38.7)%
POLR	9,910	11,772	(15.8)%
Structured Sales	9,465	9,296	1.8%
Wholesale	951	—	—
Total MWH Sales	54,710	76,793	(28.8)%

The following table summarizes the price and volume factors contributing to changes in revenues in the first nine months of 2015 compared with the same period of 2014:

MWH Sales Channel:	Source of Change in Revenues Increase (Decrease) Sales Volumes	Prices	Gain on Settled Contracts	Capacity Revenue	Total
	(In millions)				
Direct	$(865)	$3	$—	$—	$(862)
Governmental Aggregation	(187)	65	—	—	(122)
Mass Market	(137)	5	—	—	(132)
POLR	(108)	12	—	—	(96)
Structured Sales	7	45	—	—	52
Wholesale	21	—	(45)	265	241

The Direct, Governmental Aggregation and Mass Market customer base was 1.7 million as of September 30, 2015, compared to 2.3 million as of September 30, 2014, reflecting FES' efforts to reposition its sales portfolio as discussed above. Additionally, although unit pricing was higher year-over-year in the Direct, Governmental Aggregation, and

Mass Market channels, the increase was primarily attributable to higher capacity expense as discussed below, which is a component of the retail price. The increase in Direct unit prices was partially offset by ancillary pass-through revenues recognized in 2014 associated with PJM expenses incurred in January 2014, as further discussed below.

The decrease in POLR sales of $96 million was due to lower volumes, partially offset by higher rates associated with recent POLR auctions. Structured Sales increased $52 million primarily due to market conditions that increased the gains on various structured financial sales contracts and higher structured transaction volumes.

Wholesale revenues increased $241 million due to an increase in capacity revenue from higher capacity prices and an increase in short-term (net hourly position) transactions, partially offset by lower net gains on financially settled contracts, primarily with AE Supply. Additionally, although wholesale short-term transactions increased year-over-year, lower economic dispatch of fossil generating units resulting from low spot market energy prices limited additional wholesale sales volumes.

Transmission revenue decreased $66 million in the first nine months of 2015, as compared to the same period of 2014, primarily due to lower congestion revenue associated with market conditions resulting from the extreme weather events in 2014.

Other revenue increased $17 million primarily due to higher lease revenues from additional repurchased equity interests in affiliated sale and leasebacks in November of 2014. FES earns lease revenue associated with the equity interests it purchased.

Operating Expenses -

Total operating expenses decreased by $1,429 million in the first nine months of 2015 compared to the same period of 2014.

The following table summarizes the factors contributing to the changes in fuel and purchased power costs in the first nine months of 2015 compared with the same period of 2014:

	Source of Change Increase (Decrease)				
Operating Expense	Volumes	Prices	Settled Contracts	Capacity Expense	Total
	(In millions)				
Fossil Fuel	$(154)	$(20)	$(79)	$—	$(253)
Nuclear Fuel	6	(10)	—	—	(4)
Affiliated Purchased Power	8	1	38	—	47
Non-affiliated Purchased Power[1]	(1,248)	(291)	472	129	(938)

[1] In the first nine months of 2014, 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 $257 million, primarily due to lower economic dispatch of fossil units resulting from low wholesale spot market energy prices, partially offset by a slight increase in nuclear generation. Lower unit prices also contributed to the decrease, resulting from the suspension of the DOE nuclear disposal fee, which became effective May 16, 2014, and lower coal prices. Additionally, fuel costs were impacted by a decrease in settlement and termination costs related to coal contracts. In the first nine months of 2015, a pre-tax gain of approximately $12 million was recognized associated with the elimination of an obligation under an existing coal contract. In the first nine months of 2014, a termination of a coal contract associated with deactivated plants resulted in a pre-tax loss of $67 million.

Non-affiliated purchased power costs decreased $938 million due to lower volumes ($1,022 million) and decreased prices, net of financials ($45 million), partially offset by higher capacity expenses ($129 million). Lower volumes were primarily due to decreased load requirements resulting from FES' sales strategy, partially offset by decreased fossil generation discussed above. The decrease in unit prices was primarily associated with the market conditions resulting from the extreme weather events in January 2014. The increase in capacity expense, which is a component of FES' retail price, was primarily the result of higher capacity rates associated with FES' retail sales obligations.

Other operating expenses decreased $264 million in the first nine months of 2015, compared to the same period of 2014, primarily due to the following:

- Fossil operating costs decreased $8 million primarily due fewer planned and unplanned outages for the nine months ended September 30, 2015 as compared to the same period of 2014, partially offset by higher employee benefit expenses.

- Nuclear operating costs increased $49 million as a result of higher employee benefit expenses and higher planned outage costs.

- Transmission expenses decreased $135 million primarily due to lower operating reserve and market-based ancillary costs associated with market conditions resulting from the extreme weather events in the first quarter of 2014, of which a portion were passed through to commercial and industrial customers, as discussed above.

- Other operating expenses decreased $170 million primarily due to a $128 million decrease in mark-to-market expenses on commodity contract positions and a $58 million decrease in retail-related costs, partially offset by a $16 million impairment associated with non-core assets during the second quarter of 2015.

Depreciation expense increased $4 million as a result of a higher asset base from projects such as MATS compliance and the Davis-Besse steam generator replacement completed in May 2014.

General taxes decreased $21 million primarily due to lower gross receipts taxes associated with decreased retail sales volumes.

Other Expense —

Total other expense increased $60 million in the first nine months of 2015, compared to the same period of 2014, primarily due to higher OTTI on NDT investments, partially offset by the absence of a $6 million loss on debt redemptions incurred in the first nine months of 2014.

Discontinued Operations —

Discontinued operations decreased $116 million in the first nine months of 2015 compared to the same period of 2014 primarily due to a pre-tax gain of approximately $177 million associated with the sale of certain hydroelectric facilities on February 12, 2014.

Income Taxes (Benefits) —

FES' effective tax rate from continuing operations for the nine months ended September 30, 2015 and 2014 was 40.0% and 39.4%, respectively.

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, 2015, 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

In addition to the other information set forth in this report, the reader should carefully consider the factors discussed in "Item 1A. Risk Factors" in the Registrants' Annual Report on Form 10-K for the year ended December 31, 2014, which could materially affect the Registrants' business, financial condition or future results.

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

(c) The table below sets forth information on a monthly basis regarding FE's purchases of its common stock during the third quarter of 2015:

	Period			
	July	August	September	Third Quarter
Total Number of Shares Purchased[1]	—	1,706	20	1,726
Average Price Paid per Share	$—	$31.96	$31.96	$31.96
Total Number of Shares Purchased As Part of Publicly Announced Plans or Programs[2]	—	—	—	—
Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs	—	—	—	—

(1) Share amounts reflect shares that were surrendered to FE by a participant under our 2007 Incentive Plan to satisfy tax withholding obligations relating to the vesting of a restricted stock award and the subsequent dividend reinvestments on such equity award. The total number of shares repurchased represents the net shares surrendered to FE or issued, as the case may be, to satisfy tax withholding. All such repurchased shares are now held as treasury shares.

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

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

	10.1	FirstEnergy Corp. Amended and Restated Executive Deferred Compensation Plan, dated July 20, 2015, and effective as of November 1, 2015 (incorporated by reference to FE's Form 8-K filed July 24, 2015, Exhibit 10.1, File No. 333-21011)
	10.2	Performance-Earned Restricted Stock Award Agreement, effective August 10, 2015, by and between FirstEnergy Corp. and James F. Pearson (incorporated by reference to FE's Form 8-K filed August 7, 2015, Exhibit 10.1, File No. 333-21011)
	10.3	Performance-Earned Cash Award Agreement, effective August 10, 2015, by and between FirstEnergy Corp. and James H. Lash (incorporated by reference to FE's Form 8-K filed August 7, 2015, Exhibit 10.2, File No. 333-21011)
	10.4	FirstEnergy Corp. 2017 Change in Control Severance Plan, dated as of September 15, 2015, and effective as of January 1, 2017 (incorporated by reference to FE's Form 8-K filed September 18, 2015, Exhibit 10.1, File No. 333-21011)
	10.5	Waiver of Participation in the FirstEnergy Corp. Change in Control Severance Plan, dated as of September 15, 2015 (incorporated by reference to FE's Form 8-K filed September 18, 2015, Exhibit 10.2, File No. 333-21011)
	10.6	Non-Competition and Non-Disparagement Agreement, dated as of September 15, 2015 (incorporated by reference to FE's Form 8-K filed September 18, 2015, Exhibit 10.3, File No. 333-21011)
(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, 2015, 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, 2015, 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.

October 29, 2015

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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