FIRSTENERGY CORP
Form 10-Q
November 04, 2016

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, 2016

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, 2016
FirstEnergy Corp., $0.10 par value	425,743,282
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 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 web site and recognize FirstEnergy’s 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 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® App 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 web site, Twitter® handle or Facebook® page, 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.
- The accomplishment of our regulatory and operational goals in connection with our transmission investment plan, including, but not limited to, the proposed transmission asset transfer to MAIT, and the effectiveness of our 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 and resulting outcomes on the 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.
- 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 prices, and their availability and impact on margins and asset valuations, including without limitation impairments thereon.
- The risks and uncertainties at the CES segment, including FES and its subsidiaries and FENOC, related to continued depressed wholesale energy and capacity markets, and the viability and/or success of strategic business alternatives, such as potential CES generating unit asset sales, the potential conversion of the remaining generation fleet from competitive operations to a regulated or regulated-like construct or the potential need to deactivate additional generating units.
- 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 older regulated and competitive units, including the impact on vendor commitments, such as long-term fuel and transportation agreements, and as it relates 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, such as long-term fuel and transportation agreements.
- 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 cash flow improvement plan and 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 significant 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.
- Further 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, increase requirements to post additional collateral to support, or accelerate payments under outstanding commodity positions, LOCs and other financial guarantees, and the impact of these events on the financial condition and liquidity of FirstEnergy and/or its subsidiaries, specifically the subsidiaries within the CES segment.
- The risks and uncertainties surrounding FirstEnergy's need to obtain waivers from its bank group under FirstEnergy's credit facilities caused by a debt to total capitalization ratio, as defined under each of the revolving credit facilities, in excess of 65% resulting from impairment charges or other events at CES.
- 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 and other disruptions to our information technology system that may compromise our generation, transmission and/or distribution services and data security breaches of sensitive data, intellectual property and proprietary or personally identifiable information regarding our business, employees, shareholders, customers, suppliers, business partners and other individuals in our data centers and on our networks.
- 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 factors should not be construed as exhaustive and should be read in conjunction with the other cautionary statements and risks that are included in FirstEnergy's and FES' filings with the SEC, including but not limited to the most recent Annual Report on Form 10-K and any subsequent Quarterly Reports on Form 10-Q. 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
FENOC	FirstEnergy Nuclear Operating Company, which operates NG's nuclear generating facilities
FES	FirstEnergy Solutions Corp., together with its consolidated subsidiaries, 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 and West Virginia electric utility operating subsidiary
Penn	Pennsylvania Power Company, a Pennsylvania electric utility operating subsidiary of OE
Pennsylvania Companies	ME, PN, Penn and WP

PN	Pennsylvania Electric Company, a Pennsylvania electric utility operating subsidiary
PNBV	PNBV Capital Trust, a special purpose entity created by OE in 1996
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

ARO	Asset Retirement Obligation
ARR	Auction Revenue Right
ASU	Accounting Standards Update
BGS	Basic Generation Service
BNSF	BNSF Railway Company
BRA	PJM RPM Base Residual Auction
CAA	Clean Air Act
CCR	Coal Combustion Residuals
CDWR	California Department of Water Resources
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act of 1980
CFIP	Cash Flow Improvement Project
CFR	Code of Federal Regulations
CO_2	Carbon Dioxide
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
DMR	Distribution Modernization Rider
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 IV	Electric Security Plan IV
ESP IV PPA	Unit Power Agreement entered into on April 1, 2016 by and between the Ohio Companies and FES
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
HB554	Ohio House Bill No. 554
HCl	Hydrochloric Acid

ICE	Intercontinental Exchange, Inc.
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
ISO	Independent System Operator
kV	Kilovolt
KWH	Kilowatt-hour
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.
MOPR	Minimum Offer Price Rule
MVP	Multi-Value Project
MW	Megawatt
MWH	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NDT	Nuclear Decommissioning Trust
NERC	North American Electric Reliability Corporation
Ninth Circuit	United States Court of Appeals for the Ninth Circuit
NJBPU	New Jersey Board of Public Utilities
NMB	Non-Market Based
NOAC	Northwestern Ohio Aggregation Coalition
NOL	Net Operating Loss
NOV	Notice of Violation
NOx	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NSR	New Source Review
NUG	Non-Utility Generation
NYPSC	New York State Public Service Commission
OCC	Ohio Consumers' Counsel
OPEB	Other Post-Employment Benefits
OTTI	Other Than Temporary Impairments
OVEC	Ohio Valley Electric Corporation
PA DEP	Pennsylvania Department of Environmental Protection
PCB	Polychlorinated Biphenyl
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
PPA	Purchase Power Agreement
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
RFC	ReliabilityFirst Corporation
RFP	Request for Proposal

GLOSSARY OF TERMS, Continued

RGGI	Regional Greenhouse Gas Initiative
ROE	Return on Equity
RPM	Reliability Pricing Model
RRS	Retail Rate Stability
RSS	Rich Site Summary
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard & Poor’s Ratings Service
SB221	Amended Substitute Ohio Senate Bill No. 221
SB310	Substitute Ohio Senate Bill No. 310
SB320	Ohio Senate Bill No. 320
SBC	Societal Benefits Charge
SEC	United States Securities and Exchange Commission
SEC Regulation FD	SEC Regulation Fair Disclosure
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
Sixth Circuit	United States Court of Appeals for the Sixth Circuit
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
TO	Transmission Owner
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
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 (LOSS)
(Unaudited)

(In millions, except per share amounts)	For the Three Months Ended September 30 2016	For the Three Months Ended September 30 2015	For the Nine Months Ended September 30 2016	For the Nine Months Ended September 30 2015
REVENUES:				
Regulated Distribution	$2,702	$2,624	$7,423	$7,425
Regulated Transmission	285	248	824	755
Unregulated businesses	930	1,251	2,940	3,305
Total revenues*	3,917	4,123	11,187	11,485
OPERATING EXPENSES:				
Fuel	450	482	1,269	1,378
Purchased power	979	1,209	2,992	3,311
Other operating expenses	953	842	2,835	2,799
Provision for depreciation	311	328	974	969
Amortization of regulatory assets, net	98	110	222	201
General taxes	265	236	786	747
Impairment of assets (Note 2)	—	8	1,447	24
Total operating expenses	3,056	3,215	10,525	9,429
OPERATING INCOME	861	908	662	2,056
OTHER INCOME (EXPENSE):				
Investment income (loss)	28	(28)	75	(14)
Interest expense	(286)	(285)	(863)	(846)
Capitalized financing costs	28	26	79	93
Total other expense	(230)	(287)	(709)	(767)
INCOME (LOSS) BEFORE INCOME TAXES	631	621	(47)	1,289
INCOME TAXES	251	226	334	485
NET INCOME (LOSS)	$380	$395	$(381)	$804
EARNINGS (LOSSES) PER SHARE OF COMMON STOCK:				
Basic	$0.89	$0.94	$(0.90)	$1.91
Diluted	$0.89	$0.93	$(0.90)	$1.90
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING:				
Basic	425	423	425	422

Diluted	427	424	425	423
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$0.72	$0.72	$1.44	$1.44

* Includes excise tax collections of $111 million and $109 million in the three months ended September 30, 2016 and 2015, respectively, and $310 million and $320 million in the nine months ended September 30, 2016 and 2015, respectively.

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

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

	For the Three Months Ended September 30		For the Nine Months Ended September 30	
(In millions)	2016	2015	2016	2015
NET INCOME (LOSS)	$380	$395	$(381)	$804
OTHER COMPREHENSIVE INCOME (LOSS):				
Pension and OPEB prior service costs	(18)	(31)	(54)	(94)
Amortized losses on derivative hedges	2	2	6	4
Change in unrealized gains on available-for-sale securities	4	(11)	67	(21)
Other comprehensive income (loss)	(12)	(40)	19	(111)
Income taxes (benefits) on other comprehensive income (loss)	(5)	(15)	6	(42)
Other comprehensive income (loss), net of tax	(7)	(25)	13	(69)
COMPREHENSIVE INCOME (LOSS)	$373	$370	$(368)	$735

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, 2016	December 31, 2015
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 551	$ 131
Receivables-		
Customers, net of allowance for uncollectible accounts of $61 in 2016 and $69 in 2015	1,470	1,415
Other, net of allowance for uncollectible accounts of $3 in 2016 and $5 in 2015	159	180
Materials and supplies	699	785
Prepaid taxes	204	135
Derivatives	152	157
Collateral	89	70
Other	156	167
	3,480	3,040
PROPERTY, PLANT AND EQUIPMENT:		
In service	50,889	49,952
Less — Accumulated provision for depreciation	15,450	15,160
	35,439	34,792
Construction work in progress	2,394	2,422
	37,833	37,214
INVESTMENTS:		
Nuclear plant decommissioning trusts	2,502	2,282
Other	533	506
	3,035	2,788
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill (Note 2)	5,618	6,418
Regulatory assets	1,088	1,348
Other	907	1,286
	7,613	9,052
	$ 51,961	$ 52,094
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 1,216	$ 1,166
Short-term borrowings	2,975	1,708
Accounts payable	944	1,075
Accrued taxes	537	519
Accrued compensation and benefits	365	334
Derivatives	91	106
Other	915	694
	7,043	5,602
CAPITALIZATION:		
Common stockholders' equity-		
Common stock, $0.10 par value, authorized 490,000,000 shares - 425,743,282 and 423,560,397 shares outstanding as of September 30, 2016 and December 31, 2015,	43	42

respectively		
Other paid-in capital	10,012	9,952
Accumulated other comprehensive income	184	171
Retained earnings	1,264	2,256
Total common stockholders' equity	11,503	12,421
Noncontrolling interest	—	1
Total equity	11,503	12,422
Long-term debt and other long-term obligations	18,532	19,099
	30,035	31,521
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	7,136	6,773
Retirement benefits	4,080	4,245
Asset retirement obligations	1,459	1,410
Deferred gain on sale and leaseback transaction	765	791
Adverse power contract liability	174	197
Other	1,269	1,555
	14,883	14,971
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 12)		
	$ 51,961	$ 52,094

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	For the Nine Months Ended September 30	
(In millions)	2016	2015
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income (loss)	$(381)	$804
Adjustments to reconcile net income (loss) to net cash from operating activities-		
Depreciation and amortization, including nuclear fuel, regulatory assets and customer intangible asset amortization	1,440	1,383
Deferred purchased power and other costs	(34)	(73)
Deferred income taxes and investment tax credits, net	318	428
Impairment of assets (Note 2)	1,447	24
Investment impairments	13	70
Deferred costs on sale leaseback transaction, net	36	37
Retirement benefits, net of payments	45	(18)
Pension trust contributions	(297)	(143)
Commodity derivative transactions, net (Note 9)	(10)	(64)
Lease payments on sale and leaseback transaction	(94)	(102)
Changes in current assets and liabilities-		
Receivables	(34)	7
Materials and supplies	45	32
Prepayments and other current assets	(28)	(43)
Accounts payable	(17)	(285)
Accrued taxes	(81)	(68)
Accrued interest	36	37
Accrued compensation and benefits	2	16
Other current liabilities	17	26
Cash collateral, net	25	59
Other	132	190
Net cash provided from operating activities	2,580	2,317
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Long-term debt	521	1,084
Short-term borrowings, net	1,275	134
Redemptions and Repayments-		
Long-term debt	(1,017)	(781)
Common stock dividend payments	(458)	(455)
Other	(5)	(11)
Net cash provided from (used for) financing activities	316	(29)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(2,156)	(2,025)
Nuclear fuel	(195)	(101)
Sales of investment securities held in trusts	1,361	1,126
Purchases of investment securities held in trusts	(1,437)	(1,213)

Asset removal costs	(101)	(111)
Other	52	37
Net cash used for investing activities	(2,476)	(2,287)
Net change in cash and cash equivalents	420	1
Cash and cash equivalents at beginning of period	131	85
Cash and cash equivalents at end of period	$551	$86

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

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

(In millions)	For the Three Months Ended September 30 2016	2015	For the Nine Months Ended September 30 2016	2015
STATEMENTS OF INCOME (LOSS)				
REVENUES:				
Electric sales to non-affiliates	$952	$1,157	$2,917	$3,146
Electric sales to affiliates	111	135	360	547
Other	37	46	124	141
Total revenues	1,100	1,338	3,401	3,834
OPERATING EXPENSES:				
Fuel	202	245	595	666
Purchased power from affiliates	191	103	440	250
Purchased power from non-affiliates	186	401	829	1,336
Other operating expenses	316	246	925	996
Provision for depreciation	83	79	250	240
General taxes	21	24	66	78
Impairment of assets (Note 2)	—	—	540	16
Total operating expenses	999	1,098	3,645	3,582
OPERATING INCOME (LOSS)	101	240	(244)	252
OTHER INCOME (EXPENSE):				
Investment income (loss)	24	(21)	56	(7)
Miscellaneous income	1	1	4	5
Interest expense — affiliates	(3)	(2)	(6)	(6)
Interest expense — other	(36)	(36)	(109)	(110)
Capitalized interest	9	8	27	26
Total other expense	(5)	(50)	(28)	(92)
INCOME (LOSS) BEFORE INCOME TAXES (BENEFITS)	96	190	(272)	160
INCOME TAXES (BENEFITS)	56	70	(5)	64
NET INCOME (LOSS)	$40	$120	$(267)	$96
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)				
NET INCOME (LOSS)	$40	$120	$(267)	$96
OTHER COMPREHENSIVE INCOME (LOSS):				
Pension and OPEB prior service costs	(3)	(4)	(10)	(12)
Amortized losses (gains) on derivative hedges	1	—	—	(2)

Change in unrealized gains on available-for-sale securities	5	(11)	61	(20)
Other comprehensive income (loss)	3	(15)	51	(34)
Income taxes (benefits) on other comprehensive income (loss)	1	(6)	20	(13)
Other comprehensive income (loss), net of tax	2	(9)	31	(21)
COMPREHENSIVE INCOME (LOSS)	$42	$111	$(236)	$75

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, 2016	December 31, 2015
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 2	$ 2
Receivables-		
Customers, net of allowance for uncollectible accounts of $6 in 2016 and $8 in 2015	225	275
Affiliated companies	482	451
Other, net of allowance for uncollectible accounts of $3 in 2016 and 2015	55	59
Notes receivable from affiliated companies	26	11
Materials and supplies	403	470
Derivatives	146	154
Collateral	85	70
Prepayments and other	72	66
	1,496	1,558
PROPERTY, PLANT AND EQUIPMENT:		
In service	14,100	14,311
Less — Accumulated provision for depreciation	5,822	5,765
	8,278	8,546
Construction work in progress	1,048	1,157
	9,326	9,703
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,542	1,327
Other	10	10
	1,552	1,337
DEFERRED CHARGES AND OTHER ASSETS:		
Customer intangibles	11	61
Goodwill (Note 2)	—	23
Property taxes	10	40
Derivatives	98	79
Other	374	367
	493	570
	$ 12,867	$ 13,168
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 182	$ 512
Short-term borrowings-		
Affiliated companies	101	—
Other	—	8
Accounts payable-		
Affiliated companies	393	542
Other	89	139
Accrued taxes	72	76
Derivatives	89	104
Other	182	181
	1,108	1,562

CAPITALIZATION:		
Common stockholder's equity-		
Common stock, without par value, authorized 750 shares - 7 shares outstanding as of September 30, 2016 and December 31, 2015	3,653	3,613
Accumulated other comprehensive income	77	46
Retained earnings	1,679	1,946
Total common stockholder's equity	5,409	5,605
Long-term debt and other long-term obligations	2,815	2,510
	8,224	8,115
NONCURRENT LIABILITIES:		
Deferred gain on sale and leaseback transaction	765	791
Accumulated deferred income taxes	734	600
Retirement benefits	219	332
Asset retirement obligations	887	831
Derivatives	50	38
Other	880	899
	3,535	3,491
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 12)		
	$ 12,867	$ 13,168

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

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

(In millions)	For the Nine Months Ended September 30 2016	2015
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$(267)	$96
Adjustments to reconcile net income (loss) to net cash from operating activities-		
Depreciation and amortization, including nuclear fuel and customer intangible asset amortization	463	422
Deferred costs on sale and leaseback transaction, net	36	37
Deferred income taxes and investment tax credits, net	90	139
Investment impairments	12	63
Pension trust contribution	(138)	—
Commodity derivative transactions, net (Note 9)	(10)	(65)
Lease payments on sale and leaseback transaction	(94)	(102)
Impairment of assets (Note 2)	540	16
Changes in current assets and liabilities-		
Receivables	19	171
Materials and supplies	25	(1)
Accounts payable	(69)	(241)
Accrued taxes	(6)	(28)
Accrued compensation and benefits	—	2
Other current liabilities	13	24
Cash collateral, net	6	107
Other	(16)	(4)
Net cash provided from operating activities	604	636
CASH FLOWS FROM FINANCING ACTIVITIES:		
New financing-		
Long-term debt	471	339
Short-term borrowings, net	101	—
Redemptions and repayments-		
Long-term debt	(503)	(382)
Short-term borrowings, net	—	(109)
Other	(7)	(5)
Net cash provided from (used for) financing activities	62	(157)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(432)	(341)
Nuclear fuel	(195)	(101)
Sales of investment securities held in trusts	576	503
Purchases of investment securities held in trusts	(619)	(546)
Cash investments	10	(10)

Loans to affiliated companies, net	(15)	—
Other	9	16
Net cash used for investing activities	(666)	(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

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 Allegheny Ventures, Inc.

FE 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 regulated and unregulated 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 two 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, 2015. These Notes to the Consolidated Financial Statements are combined for FirstEnergy and FES.

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 do not have a controlling financial interest, 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 of FE's ownership share of the entity’s earnings is reported in the Consolidated Statements of Income (Loss) and Comprehensive Income (Loss).

For the three months ended September 30, 2016 and 2015, capitalized financing costs on FirstEnergy's Consolidated Statements of Income (Loss) include $11 million and $10 million, respectively, of allowance for equity funds used during construction and $17 million and $16 million, respectively, of capitalized interest. For the nine months ended

September 30, 2016 and 2015, capitalized financing costs on FirstEnergy's Consolidated Statements of Income (Loss) include $28 million and $40 million, respectively, of allowance for equity funds used during construction and $51 million and $53 million, respectively, of capitalized interest.

During the third quarter of 2016, a reduction to depreciation of $21 million ($19 million prior to January 1, 2016) was recorded that related to prior periods. The out-of-period adjustment related to the utilization of an accelerated useful life for a component of a certain power station. Management has determined this adjustment is not material to the current period or any prior periods.

Strategic Review of Competitive Operations

FirstEnergy’s strategy is to be a fully regulated utility focusing on stable and predictable earnings and cash flow from its regulated business units. In order to execute on this strategy, FirstEnergy has begun a strategic review of its competitive operations focused on the sale of gas and hydroelectric units as well as exploring all alternatives for the remaining generation assets at FES and AE Supply. These include, but are not limited to, legislative efforts to convert generation from competitive operations to a regulated or regulated-like construct such as a regulatory restructuring in Ohio, offering generation into any process designed to address MP's generation shortfall included in its IRP, and/or a solution for nuclear generation that recognize their environmental benefits. Management anticipates that the viability of these alternatives will be determined in the near term with a target to implement these strategic options within the next 12 to 18 months and could result in material asset impairments.

Based on current market forwards, CES, including FES, expects to have more than sufficient cash flow from operations in 2017 and 2018 to fund anticipated capital expenditures with no equity contributions from FirstEnergy. However, in addition to exposure to market price volatility and operational risks, CES, including FES, faces significant financial risks that could impact its anticipated cash flow and liquidity, including, but not limited to, the following:

- Requests to post additional collateral or accelerated payments of up to $355 million resulting from current credit ratings at FES, including Moody's downgrade of the Senior Unsecured debt rating for FES to Caa1 as well as S&P's downgrade of the Senior Unsecured debt rating at FES to B, both of which occurred on November 4, 2016.
- Adverse outcomes in the previously disclosed disputes regarding long-term coal transportation contracts.
- The inability to extend or refinance debt maturities at CES, including at FES subsidiaries, in 2017 and 2018 of $130 million and $515 million, respectively.

A significant collateral call or the inability to refinance 2017 debt maturities at FES subsidiaries is expected to be addressed by FES through a combination of cash on hand, additional capital expenditure reductions, asset sales, and/or borrowings under the unregulated money pool. However, adverse outcomes in the coal transportation contracts disputes, the inability to refinance 2018 debt maturities, or lack of viable alternative strategies could cause FES to take one or more of the following actions: (i) restructuring of debt and other financial obligations, (ii) additional borrowings under the unregulated money pool, (iii) further asset sales or plant deactivations, and/or (iv) seek protection under bankruptcy laws. In the event FES seeks such protection, FENOC may similarly seek protection under bankruptcy laws.

Material asset impairments resulting from the sale or deactivation of generation assets or from a determination by management of its intent to exit competitive generation assets before the end of their estimated useful life resulting from the inability to implement alternative strategies discussed above, adverse judgments or a FES bankruptcy filing could result in an event of default under various agreements related to the indebtedness of FE. Although management expects to successfully resolve any FE defaults through waivers or other actions on acceptable terms and conditions, the failure to do so would have a material and adverse impact on FirstEnergy’s financial condition, and FirstEnergy cannot provide any assurance that it will be able to successfully resolve any such defaults on satisfactory terms.

New Accounting Pronouncements

In May 2014, the FASB issued ASU 2014-09, "Revenue from Contracts with Customers". Subsequent accounting standards updates have been issued which amend and/or clarify the application of ASU 2014-09. The core principle of the new guidance is that an entity recognizes revenue 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. More detailed disclosures will also be required to enable users of financial statements to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. For public business entities, the new revenue recognition guidance will be effective for annual and interim reporting periods beginning after December 15, 2017. Earlier adoption is permitted for annual and interim reporting periods beginning after December 15, 2016. The standards 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 these standards.

In February 2015, the FASB issued ASU 2015-02, "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. 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's adoption of ASU 2015-02, on January 1, 2016, did not result in a change in the consolidation of VIEs by FE or its subsidiaries.

In April 2015, the FASB issued ASU 2015-03, "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. In addition, in August 2015, the FASB issued ASU 2015-15, "Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements", which allows debt issuance costs related to line of credit arrangements to be presented as an asset and amortized ratably over the term of the arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit. FirstEnergy adopted ASU 2015-15 and ASU 2015-03 beginning January 1, 2016. As of December 31, 2015, FirstEnergy and FES reclassified $93 million and $17 million of debt issuance costs included in Deferred charges and other assets to Long-term debt and Other long-term obligations. FirstEnergy has elected to continue presenting debt issuance costs relating to its revolving credit facilities as an asset.

In January of 2016, the FASB issued ASU 2016-01, "Financial Instruments-Overall: Recognition and Measurement of Financial Assets and Financial Liabilities", which primarily affects the accounting for equity investments, financial liabilities under the fair value option, and the presentation and disclosure requirements for financial instruments. In addition, the FASB clarified guidance related to the valuation allowance assessment when recognizing deferred tax assets resulting from unrealized losses on available-for-sale debt securities. The ASU will be effective in fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Early adoption for certain provisions can be elected for all financial statements of fiscal years and interim periods that have not yet been issued or that have not yet been made available for issuance. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

In February 2016, the FASB issued ASU 2016-02, "Leases (Topic 842)", which will require organizations that lease assets with lease terms of more than 12 months to recognize assets and liabilities for the rights and obligations created by those leases on their balance sheets. In addition, new qualitative and quantitative disclosures of the amounts, timing, and uncertainty of cash flows arising from leases will be required. The ASU will be effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018, with early adoption permitted. Lessors and lessees will be required to apply a modified retrospective transition approach, which requires adjusting the accounting for any leases existing at the beginning of the earliest comparative period presented in the adoption-period financial statements. Any leases that expire before the initial application date will not require any accounting adjustment. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

In March of 2016, the FASB issued ASU 2016-09, "Improvements to Employee Share-Based Payment Accounting", which simplifies several aspects of the accounting for employee share-based payment. The new guidance will require all income tax effects of awards to be recognized in the income statement when the awards vest or are settled. It also will not require liability accounting when an employer repurchases more of an employee’s shares for tax withholding purposes. The ASU will be effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016, with early adoption permitted. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

In June 2016, the FASB issued ASU 2016-13, “Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments,” which removes all recognition thresholds and will require companies to recognize an allowance for credit losses for the difference between the amortized cost basis of a financial instrument and the amount of amortized cost that the company expects to collect over the instrument’s contractual life. The ASU is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019. Early adoption is permitted for fiscal years beginning after December 15, 2018. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

In August 2016, the FASB issued ASU 2016-15, "Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments". The standard is intended to eliminate diversity in practice in how certain cash receipts and cash payments are presented and classified in the statement of cash flows. The guidance is effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2017. Early adoption is permitted for all entities. FirstEnergy does not expect this ASU to have a material effect on its financial statements.

In October 2016, the FASB issued ASU 2016-16, " Accounting for Income Taxes: Intra-Entity Asset Transfers of Assets Other than Inventory." ASU 2016-16 eliminates the exception for all intra-entity sales of assets other than inventory, which allows companies to defer the tax effects of intra-entity asset transfers. As a result, a reporting entity would recognize the tax expense from the sale of the asset in the seller’s tax jurisdiction when the intra-entity transfer occurs, even though the pre-tax effects of that transaction are eliminated in consolidation. Any deferred tax asset that arises in the buyer’s jurisdiction would also be recognized at the time of the transfer. The guidance is effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2017. Early adoption is permitted and the modified retrospective approach will be required for transition to the new guidance, with a cumulative-effect adjustment recorded in retained earnings as of the beginning of the period of adoption. FirstEnergy is currently evaluating the impact on its financial statements of adopting this standard.

Additionally, during 2016, the FASB issued the following ASUs:

- ASU 2016-05, “Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships,”
- ASU 2016-06, “Contingent Put and Call Options in Debt Instruments (a consensus of the FASB Emerging Issues Task Force),"

- ASU 2016-07, “Simplifying the Transition to the Equity Method of Accounting," and
- ASU 2016-17, “Consolidation (Topic 810): Interests Held through Related Parties That Are under Common Control.”

FirstEnergy does not expect these ASUs to have a material effect on its financial statements.

2. ASSET IMPAIRMENTS

Plant Impairments

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

On July 19, 2016, FirstEnergy and FES committed to exit operations of the Bay Shore Unit 1 generating station (136 MW) by October 1, 2020, through either sale or deactivation and to deactivate Units 1-4 of the W. H. Sammis generating station (720 MW) by May 31, 2020. As a result, FirstEnergy recorded a non-cash pre-tax impairment charge of $647 million ($517 million - FES) in the second quarter of 2016, which is included in Impairment of assets on the Consolidated Statement of Income (Loss) and included within the results of the CES segment. PJM has approved the W.H Sammis Units 1-4 and Bay Shore Unit 1 deactivations pending review by the Independent Market Monitor. In addition, FirstEnergy and FES recorded termination and settlement costs on fuel contracts of approximately $58 million (pre-tax) in the second quarter of 2016 resulting from plant retirements and deactivations.

During the first nine months of 2015, FirstEnergy and FES recognized impairment charges of $24 million and $16 million, respectively, associated with certain transportation equipment and facilities. In order to conform to current year presentation, the charge was reclassified from Other operating expenses in the Consolidated Statement of Income (Loss) to Impairment of assets.

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 the changes in the carrying value of goodwill for the nine months ended September 30, 2016:

Goodwill	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Consolidated
	(In millions)			
Balance as of December 31, 2015	$5,092	$ 526	$ 800	$ 6,418
Impairment	—	—	(800)	(800)
Balance as of September 30, 2016	$5,092	$ 526	$ —	$ 5,618

FirstEnergy tests goodwill for impairment annually as of July 31 and considers more frequent testing if indicators of potential impairment arise.

As a result of low capacity prices associated with the 2019/2020 PJM Base Residual Auction in May 2016, as well as its annual update to its fundamental long-term capacity and energy price forecast, FirstEnergy determined that an interim impairment analysis of the CES reporting unit’s goodwill was necessary during the second quarter of 2016.

Consistent with FirstEnergy’s annual goodwill impairment test, a discounted cash flow analysis was used to determine the fair value of the CES reporting unit for purposes of step one of the interim goodwill impairment test. Key assumptions incorporated into the CES discounted cash flow analysis requiring significant management judgment included the following:

- Future Energy and Capacity Prices: Observable market information for near-term forward power prices, PJM auction results for near term capacity pricing, and a longer-term fundamental 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: 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: 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 9.50%, based on selected comparable companies' capital structure, return on debt and return on equity.
- 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 impairment analysis, FirstEnergy determined that the carrying value of goodwill exceeded its fair value and recognized a non-cash pre-tax impairment charge of $800 million ($23 million - FES) in the second quarter of 2016, which is included within the caption Impairment of assets in the Consolidated Statement of Income (Loss).

As of July 31, 2016, FirstEnergy performed a qualitative assessment of the Regulated Distribution and Regulated Transmission reporting units' goodwill, assessing economic, industry and market considerations in addition to the reporting units' 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.

Termination of Customer Contract

During the third quarter of 2016, FES recorded a pre-tax charge of $32 million associated with the termination of a customer contract, which is included in Other operating expenses in the Consolidated Statement of Income (Loss).

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)	For the Three Months Ended September 30		For the Nine Months Ended September 30	
Reconciliation of Basic and Diluted Earnings per Share of Common Stock	2016	2015	2016	2015
Net income (loss)	$380	$395	$(381)	$804
Weighted average number of basic shares outstanding	425	423	425	422
Assumed exercise of dilutive stock options and awards(1)	2	1	—	1
Weighted average number of diluted shares outstanding	427	424	425	423
Basic earnings (losses) per share of common stock	$0.89	$0.94	$(0.90)	$1.91
Diluted earnings (losses) per share of common stock	$0.89	$0.93	$(0.90)	$1.90

(1) For the nine months ended September 30, 2016, three million shares were excluded from the calculation of diluted shares outstanding, as their inclusion would be antidilutive as a result of the net loss for the period. For the three months ended September 30, 2016 and 2015, and for the nine months ended September 30, 2015, one million shares were excluded from the calculation of diluted shares outstanding, as their inclusion would be antidilutive.

4. PENSION AND OTHER POSTEMPLOYMENT BENEFITS

Through October 2016, FirstEnergy satisfied its minimum required funding obligations to its qualified pension plan for the year with contributions of $382 million ($85 million in October 2016), including $138 million at FES. Depending on, among other things, market conditions, FirstEnergy expects to make additional contributions to its qualified pension plan in 2016 of up to $500 million of equity to address its funding obligations for future years.

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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	2016	2015	2016	2015
	(In millions)			
Service costs	$48	$49	$2	$2
Interest costs	99	96	7	7
Expected return on plan assets	(100)	(111)	(7)	(9)
Amortization of prior service costs (credits)	2	2	(20)	(33)
Net periodic costs (credits)	$49	$36	$(18)	$(33)

Components of Net Periodic Benefit Costs (Credits)	Pension		OPEB	
For the Nine Months Ended September 30	2016	2015	2016	2015
	(In millions)			
Service costs	$144	$145	$4	$4
Interest costs	298	288	22	21
Expected return on plan assets	(297)	(333)	(23)	(25)
Amortization of prior service costs (credits)	6	6	(60)	(100)
Net periodic costs (credits)	$151	$106	$(57)	$(100)

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

	Pension		OPEB	
	2016	2015	2016	2015
	(In millions)			
For the Three Months Ended September 30	$6	$ 4	$(4)	$(5)
For the Nine Months Ended September 30	18	12	(12)	(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 FirstEnergy and FES were as follows:

Net Periodic Benefit Expense (Credit)	Pension		OPEB	
For the Three Months Ended September 30	2016	2015	2016	2015
	(In millions)			
FirstEnergy	$35	$ 25	$(11)	$(21)
FES	5	4	(4)	(4)

Net Periodic Benefit Expense (Credit)	Pension		OPEB	
For the Nine Months Ended September 30	2016	2015	2016	2015
	(In millions)			
FirstEnergy	$107	$ 74	$(41)	$(66)
FES	17	12	(12)	(12)

5. ACCUMULATED OTHER COMPREHENSIVE INCOME

The changes in AOCI, net of tax, in the three and nine months ended September 30, 2016 and 2015, for FirstEnergy are included in the following tables:

FirstEnergy	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
	(In millions)			
AOCI Balance as of July 1, 2016	$(31)	$ 58	$ 164	$191
Other comprehensive income before reclassifications	—	21	—	21
Amounts reclassified from AOCI	2	(17)	(18)	(33)
Other comprehensive income (loss)	2	4	(18)	(12)
Income taxes (benefits) on other comprehensive income (loss)	—	2	(7)	(5)
Other comprehensive income (loss), net of tax	2	2	(11)	(7)
AOCI Balance as of September 30, 2016	$(29)	$ 60	$ 153	$184
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 taxes (benefits) on other comprehensive income (loss)	1	(4)	(12)	(15)
Other comprehensive income (loss), net of tax	1	(7)	(19)	(25)
AOCI Balance as of September 30, 2015	$(35)	$ 12	$ 200	$177

	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, 2016	$(33)	$ 18	$ 186	$171
Other comprehensive income before reclassifications	—	109	—	109
Amounts reclassified from AOCI	6	(42)	(54)	(90)
Other comprehensive income (loss)	6	67	(54)	19
Income taxes (benefits) on other comprehensive income (loss)	2	25	(21)	6
Other comprehensive income (loss), net of tax	4	42	(33)	13
AOCI Balance as of September 30, 2016	$(29)	$ 60	$ 153	$184

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 taxes (benefits) on other comprehensive income (loss)	2	(8)	(36)	(42)
Other comprehensive income (loss), net of tax	2	(13)	(58)	(69)
AOCI Balance as of September 30, 2015	$(35)	$ 12	$ 200	$177

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The following amounts were reclassified from AOCI for FirstEnergy in the three and nine months ended September 30, 2016 and 2015:

Reclassifications from AOCI[2]	For the Three Months Ended September 30		For the Nine Months Ended September 30		Affected Line Item in Consolidated Statements of Income (Loss)
	2016	2015	2016	2015	
	(In millions)				
Gains & losses on cash flow hedges					
Commodity contracts	$—	$—	$—	$(2)	Other operating expenses
Long-term debt	2	2	6	6	Interest expense
	2	2	6	4	Total before taxes
	—	(1)	(2)	(2)	Income taxes
	$2	$1	$4	$2	Net of tax
Unrealized gains on AFS securities					
Realized gains on sales of securities	$(17)	$(3)	$(42)	$(20)	Investment income (loss)
	7	1	16	7	Income taxes
	$(10)	$(2)	$(26)	$(13)	Net of tax
Defined benefit pension and OPEB plans					
Prior-service costs	$(18)	$(31)	$(54)	$(94)	[1]
	7	12	21	36	Income taxes
	$(11)	$(19)	$(33)	$(58)	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 (Loss) from AOCI.

The changes in AOCI, net of tax, in the three and nine months ended September 30, 2016 and 2015, 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, 2016	$(10)	$ 50	$ 35	$75
Other comprehensive income before reclassifications	—	22	—	22
Amounts reclassified from AOCI	1	(17)	(3)	(19)
Other comprehensive income (loss)	1	5	(3)	3
Income taxes (benefits) on other comprehensive income (loss)	—	2	(1)	1
Other comprehensive income (loss), net of tax	1	3	(2)	2
AOCI Balance as of September 30, 2016	$(9)	$ 53	$ 33	$77
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)
Other comprehensive loss, net of tax	—	(6)	(3)	(9)
AOCI Balance as of September 30, 2015	$(9)	$ 10	$ 35	$36

	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, 2016	$(9)	$ 16	$ 39	$46
Other comprehensive income before reclassifications	—	102	—	102
Amounts reclassified from AOCI	—	(41)	(10)	(51)
Other comprehensive income (loss)	—	61	(10)	51
Income taxes (benefits) on other comprehensive income (loss)	—	24	(4)	20
Other comprehensive income (loss), net of tax	—	37	(6)	31
AOCI Balance as of September 30, 2016	$(9)	$ 53	$ 33	$77

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)
Other comprehensive loss, net of tax	(2)	(11)	(8)	(21)
AOCI Balance as of September 30, 2015	$(9)	$ 10	$ 35	$36

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The following amounts were reclassified from AOCI for FES in the three and nine months ended September 30, 2016 and 2015:

Reclassifications from AOCI[(2)]	For the Three Months Ended September 30		For the Nine Months Ended September 30		Affected Line Item in Consolidated Statements of Income (Loss)
	2016	2015	2016	2015	
	(In millions)				
Gains & losses on cash flow hedges					
Commodity contracts	$1	$—	$—	$(2)	Other operating expenses
	—	—	—	—	Income taxes
	$1	$—	$—	$(2)	Net of tax
Unrealized gains on AFS securities					
Realized gains on sales of securities	$(17)	$(3)	$(41)	$(18)	Investment income (loss)
	6	1	15	7	Income taxes
	$(11)	$(2)	$(26)	$(11)	Net of tax
Defined benefit pension and OPEB plans					
Prior-service costs	$(3)	$(4)	$(10)	$(12)	[(1)]
	1	1	4	4	Income taxes
	$(2)	$(3)	$(6)	$(8)	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 2016 and 2015. 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 for the three months ended September 30, 2016 and 2015 was 39.8% and 36.4%, respectively.

Changes in FirstEnergy's effective tax rate for the nine months ended September 30, 2016 as compared to the same period of 2015, resulted from the second quarter of 2016 impairment of $800 million of goodwill (as described in Note 2), of which $433 million is non-deductible for tax purposes. Additionally, $159 million of valuation allowances were recorded in the second quarter of 2016 against state and local NOL carryforwards that management believes, more likely than not, will not be realized based primarily on projected taxable income reflecting updates to FirstEnergy's annual long-term fundamental pricing model for energy and capacity, as well as certain statutory limitations on the utilization of state and local NOL carryforwards.

FES' effective tax rate for the three months ended September 30, 2016 and 2015 was 58.3% and 36.8%, respectively. The increase in the effective tax rate is primarily due to the impact of estimated annual permanent items on forecasted lower pre-tax income for the period.

FES’ effective tax rate for the nine months ended September 30, 2016 and 2015 was 1.8% and 40.0%, respectively. The change in the effective tax rate primarily resulted from $65 million of valuation allowances recorded against state and local NOL carryforwards that management believes, more likely than not, will not be realized as described above. Additionally, FES recorded an impairment of goodwill (as described in Note 2) in the second quarter of 2016, of which $23 million is non-deductible for tax purposes.

In March 2016, FirstEnergy recorded unrecognized tax benefits of $69 million primarily related to protective refund claims filed with the Commonwealth of Pennsylvania as a result of a recent ruling by the Commonwealth Court finding that the state’s NOL carryover limitation violated the uniformity clause and was unconstitutional. The Commonwealth of Pennsylvania has appealed this ruling to the Pennsylvania Supreme Court.

As of September 30, 2016, it is reasonably possible that approximately $54 million of unrecognized tax benefits may be resolved within the next twelve months as a result of the statute of limitations expiring and expected resolution with respect to certain claims, of which approximately $15 million would affect FirstEnergy's effective tax rate.

In February 2016, the IRS completed its examination of FirstEnergy’s 2014 federal income tax return and issued a full acceptance letter with no adjustments.

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 - PNBV, a business trust established by OE in 1996, issued certain beneficial interests and notes to fund the acquisition of a portion of the bonds issued by certain owner trusts in connection with the sale and leaseback in 1987 of a portion of OE's interest in the Perry Plant and Beaver Valley Unit 2. OE used debt and available funds to purchase the notes issued by PNBV. The beneficial ownership of PNBV includes a 3% interest by unaffiliated third parties.
- 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 thousand 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, 2016 and December 31, 2015, $339 million and $362 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, 2016 and December 31, 2015, $97 million and $128 million of the transition bonds were outstanding, respectively.
- MP and PE Environmental Funding Companies - The entities issued bonds, the proceeds of which 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. 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, 2016 and December 31, 2015, $407 million and $429 million of the environmental control bonds were outstanding, respectively.

Unconsolidated VIEs

FirstEnergy is not the primary beneficiary of the following VIEs:

- Global Holding - 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.

As discussed in Note 12, Commitments, Guarantees and Contingencies, FE is the guarantor under Global Holding's $300 million term loan facility. Failure by Global Holding to meet the terms and conditions under its term loan facility could require FE to be obligated under the provisions of its guarantee, resulting in consolidation of Global Holding by FE.

- PATH WV - PATH is a series limited liability company that is comprised of multiple series, each of which has separate rights, powers and duties regarding specified property and the series profits and losses associated with such property. A subsidiary of FE 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 PATH-WV. FirstEnergy's ownership interest in PATH-WV is subject to the equity method of accounting.
- Purchase Power Agreements - FirstEnergy evaluated its PPAs 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 14 long-term PPAs 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 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, 2016 and 2015 were $22 million and $29 million, respectively, and $78 million and $86 million during the nine months ended September 30, 2016 and 2015, respectively.

- Sale and Leaseback Transactions - OE and FES have obligations that are not included on their Consolidated Balance Sheets related to the Beaver Valley Unit 2 and 2007 Bruce Mansfield Unit 1 sale and leaseback arrangements, respectively, 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, 2016, FirstEnergy's leasehold interest was 2.60% of Beaver Valley Unit 2 and FES' leasehold interest was 93.83% of Bruce Mansfield Unit 1.

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. Upon the completion of this transaction, NG will have obtained all of the lessor equity interests at Beaver Valley Unit 2. Therefore, upon the expiration of the Beaver Valley Unit 2 leases, NG will be the sole owner of Beaver Valley Unit 2 and entitled to 100% of the unit's output.

On May 23, 2016, NG completed the purchase of the 3.75% lessor equity interests of the remaining non-affiliated leasehold interest in Perry Unit 1 for $50 million. In addition, the Perry Unit 1 leases expired in accordance with their terms on May 30, 2016, resulting in NG being the sole owner of Perry Unit 1 and entitled to 100% of the unit's output. Thereafter, OE transferred its NDT assets and related ARO to NG associated with Perry Unit 1. See Note 10, Asset Retirement Obligations, for additional information.

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, 2016:

	Maximum Exposure	Discounted Lease Payments, net	Net Exposure
	(In millions)		
FirstEnergy	$ 1,137	$ 895	$ 242
FES	1,110	887	223

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8. FAIR VALUE MEASUREMENTS

RECURRING 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 PPAs 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, 2016, from those used as of

December 31, 2015. 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, 2016. 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, 2016				December 31, 2015			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$1,242	$—	$1,242	$—	$1,245	$—	$1,245
Derivative assets - commodity contracts	7	230	—	237	4	224	—	228
Derivative assets - FTRs	—	—	13	13	—	—	8	8
Derivative assets - NUG contracts[1]	—	—	—	—	—	—	1	1
Equity securities[2]	908	—	—	908	576	—	—	576
Foreign government debt securities	—	77	—	77	—	75	—	75
U.S. government debt securities	—	173	—	173	—	180	—	180
U.S. state debt securities	—	255	—	255	—	246	—	246
Other[3]	551	126	—	677	105	212	—	317
Total assets	$1,466	$2,103	$13	$3,582	$685	$2,182	$9	$2,876
Liabilities								
Derivative liabilities - commodity contracts	$(12)	$(122)	$—	$(134)	$(9)	$(122)	$—	$(131)
Derivative liabilities - FTRs	—	—	(7)	(7)	—	—	(13)	(13)
Derivative liabilities - NUG contracts[1]	—	—	(118)	(118)	—	—	(137)	(137)
Total liabilities	$(12)	$(122)	$(125)	$(259)	$(9)	$(122)	$(150)	$(281)
Net assets (liabilities)[4]	$1,454	$1,981	$(112)	$3,323	$676	$2,060	$(141)	$2,595

(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 $(8) million and $7 million as of September 30, 2016 and December 31, 2015, respectively, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG contracts and FTRs that are classified as Level 3 in the fair value hierarchy for the periods ended September 30, 2016 and December 31, 2015:

	NUG Contracts[1]			FTRs		
	Derivative Assets	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net
	(In millions)					
January 1, 2015 Balance	$2	$ (153)	$(151)	$39	$ (14)	$25
Unrealized gain (loss)	2	(49)	(47)	(5)	(7)	(12)
Purchases	—	—	—	22	(11)	11
Settlements	(3)	65	62	(48)	19	(29)
December 31, 2015 Balance	$1	$ (137)	$(136)	$8	$ (13)	$(5)
Unrealized gain (loss)	—	(17)	(17)	(8)	1	(7)
Purchases	—	—	—	17	(8)	9
Settlements	(1)	36	35	(4)	13	9
September 30, 2016 Balance	$—	$ (118)	$(118)	$13	$ (7)	$6

[1] NUG contracts are 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, 2016:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$ 6	Model	RTO auction clearing prices	$(2.20) to $7.60	$1.00	Dollars/MWH
NUG Contracts	$ (118)	Model	Generation	400 to 3,207,000	661,000	MWH
			Regional electricity prices	$30.90 to $35.30	$32.10	Dollars/MWH

FES

Recurring Fair Value Measurements	September 30, 2016				December 31, 2015			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$714	$—	$714	$—	$678	$—	$678
Derivative assets - commodity contracts	7	230	—	237	4	224	—	228
Derivative assets - FTRs	—	—	7	7	—	—	5	5
Equity securities[(1)]	624	—	—	624	378	—	—	378
Foreign government debt securities	—	59	—	59	—	59	—	59
U.S. government debt securities	—	53	—	53	—	23	—	23
U.S. state debt securities	—	4	—	4	—	4	—	4
Other[(2)]	2	87	—	89	—	184	—	184
Total assets	$633	$1,147	$7	$1,787	$382	$1,172	$5	$1,559
Liabilities								
Derivative liabilities - commodity contracts	$(12)	$(122)	$—	$(134)	$(9)	$(122)	$—	$(131)
Derivative liabilities - FTRs	—	—	(5)	(5)	—	—	(11)	(11)
Total liabilities	$(12)	$(122)	$(5)	$(139)	$(9)	$(122)	$(11)	$(142)
Net assets (liabilities)[(3)]	$621	$1,025	$2	$1,648	$373	$1,050	$(6)	$1,417

(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 $1 million as of September 30, 2016 and December 31, 2015, 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, 2016 and December 31, 2015:

	Derivative Asset	Derivative Liability	Net Asset (Liability)
	(In millions)		
January 1, 2015 Balance	$27	$ (13)	$ 14
Unrealized gain (loss)	2	(5)	(3)
Purchases	9	(10)	(1)
Settlements	(33)	17	(16)
December 31, 2015 Balance	$5	$ (11)	$ (6)
Unrealized gain (loss)	(7)	1	(6)
Purchases	10	(5)	5
Settlements	(1)	10	9
September 30, 2016 Balance	$7	$ (5)	$ 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, 2016:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$ 2	Model	RTO auction clearing prices	($2.20) to $7.60	$0.70	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 and AFS securities.

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 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 NDTs of JCP&L, ME and PN are subject to regulatory accounting with unrealized gains and losses offset against regulatory assets.

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 and nuclear fuel disposal 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 and nuclear fuel disposal trusts as of September 30, 2016 and December 31, 2015:

	September 30, 2016(1)			December 31, 2015(2)		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
	(In millions)					
Debt securities						
FirstEnergy	$1,728	$ 69	$1,797	$1,778	$ 16	$1,794
FES	834	45	879	801	9	810
Equity securities						
FirstEnergy	$816	$ 92	$908	$542	$ 34	$576
FES	561	63	624	354	24	378

(1) Excludes short-term cash investments: FirstEnergy - $50 million; FES - $39 million.
(2) Excludes short-term cash investments: FirstEnergy - $157 million; FES - $139 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, 2016 and 2015 were as follows:

For the Three Months Ended

September 30, 2016	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	$337	$ 36	$ (15)	$(3)	$ 27
FES	135	23	(6)	(3)	16

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

For the Nine Months Ended

September 30, 2016	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	$1,361	$ 131	$ (88)	$(13)	$ 75
FES	576	90	(49)	(12)	42

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

Held-To-Maturity Securities

Unrealized gains (there were no unrealized losses) and approximate fair values of investments in held-to-maturity securities as of September 30, 2016 and December 31, 2015 are immaterial to FirstEnergy. Investments in employee benefit trusts and equity method investments totaling $276 million as of September 30, 2016 and $255 million as of December 31, 2015, 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 debt issuance costs, premiums and discounts:

	September 30, 2016		December 31, 2015	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
FirstEnergy	$19,745	$21,465	$20,244	$21,519
FES	3,003	2,662	3,027	3,121

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, 2016 and December 31, 2015.

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 $11 million as of September 30, 2016 and December 31, 2015. Since the forecasted transactions remain probable of occurring, these amounts will be amortized into earnings over the life of the hedging instruments. Less than $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 $35 million and $42 million as of September 30, 2016 and December 31, 2015, respectively. Based on current estimates, approximately $8 million of these unamortized losses are 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, 2016 and 2015.

As of September 30, 2016 and December 31, 2015, 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, 2016 and December 31, 2015, 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 $12 million and $20 million as of September 30, 2016 and December 31, 2015, respectively. During the next twelve months, approximately $8 million of unamortized gains are expected to be amortized to interest expense. Amortization of unamortized gains included in long-term debt totaled approximately $2 million during the three months ended September 30, 2016 and $3 million during the three months ended September 30, 2015. Amortization of unamortized gains included in long-term debt totaled approximately $8 million during the nine months ended September 30, 2016 and $9 million during the nine months ended September 30, 2015.

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. Derivative instruments are not used in quantities greater than forecasted needs.

As of September 30, 2016, FirstEnergy’s net asset position under commodity derivative contracts was $103 million, which related to FES positions. Under these commodity derivative contracts, FES posted $9 million of collateral and received $22 million of collateral.

Based on commodity derivative contracts held as of September 30, 2016, an increase in commodity prices of 10% would decrease net income by approximately $37 million during the next twelve months.

NUGs

As of September 30, 2016, FirstEnergy's net liability position under NUG contracts was $118 million, representing contracts held at JCP&L, ME and PN. Changes in the fair value of NUG contracts are subject to regulatory accounting treatment and do not impact earnings.

FTRs

As of September 30, 2016, FirstEnergy's and FES' net asset associated with FTRs was $6 million and $2 million, respectively, and FES posted $7 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.

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 the 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		Derivative Liabilities	Fair Value	
	September 30, 2016	December 31, 2015		September 30, 2016	December 31, 2015
	(In millions)			(In millions)	
Current Assets - Derivatives			Current Liabilities - Derivatives		
Commodity Contracts	$ 139	$ 150	Commodity Contracts	$ (84)	$ (94)
FTRs	13	7	FTRs	(7)	(12)
	152	157		(91)	(106)
Deferred Charges and Other Assets - Other			Noncurrent Liabilities - Adverse Power Contract Liability		
			NUGs[1]	(118)	(137)
Commodity Contracts	98	78	Noncurrent Liabilities - Other		
FTRs	—	1	Commodity Contracts	(50)	(37)
NUGs[1]	—	1	FTRs	—	(1)
	98	80		(168)	(175)
Derivative Assets	$ 250	$ 237	Derivative Liabilities	$ (259)	$ (281)

[1] NUG contracts are subject to regulatory accounting treatment and do not impact earnings.

FirstEnergy enters into contracts with counterparties that allow for the offsetting of derivative assets and derivative liabilities under netting arrangements with the same counterparty. 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 assets and derivative liabilities 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, 2016	Fair Value	Derivative Instruments	Cash Collateral (Received)/Pledged	Net Fair Value
	(In millions)			
Derivative Assets				
Commodity contracts	$237	$(120)	$ (22)	$95
FTRs	13	(7)	—	6
NUG contracts	—	—	—	—
	$250	$(127)	$ (22)	$101
Derivative Liabilities				
Commodity contracts	$(134)	$120	$ 8	$(6)
FTRs	(7)	7	—	—
NUG contracts	(118)	—	—	(118)

$(259)	$127	$ 8	$(124)

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December 31, 2015	Fair Value	Amounts Not Offset in Consolidated Balance Sheet: Derivative Instruments	Cash Collateral (Received)/Pledged	Net Fair Value
	(In millions)			
Derivative Assets				
Commodity contracts	$228	$ (125)	$ —	$103
FTRs	8	(8)	—	—
NUG contracts	1	—	—	1
	$237	$ (133)	$ —	$104
Derivative Liabilities				
Commodity contracts	$(131)	$ 125	$ 3	$(3)
FTRs	(13)	8	5	—
NUG contracts	(137)	—	—	(137)
	$(281)	$ 133	$ 8	$(140)

The following table summarizes the volumes associated with FirstEnergy’s outstanding derivative transactions as of September 30, 2016:

	Purchases	Sales	Net	Units
	(In millions)			
Power Contracts	9	49	(40)	MWH
FTRs	42	—	42	MWH
NUGs	3	—	3	MWH
Natural Gas	49	—	49	mmBTU

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The effect of active derivative instruments not in a hedging relationship on the Consolidated Statements of Income (Loss) during the three months and nine months ended September 30, 2016 and 2015, are summarized in the following tables:

	For the Three Months Ended September 30		
	Commodity Contracts	FTRs	Total
	(In millions)		
2016			
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense[1]	$ 19	$ (3)	$ 16
Realized Gain (Loss) Reclassified to:			
Revenues[1]	$ 32	$ 1	$ 33
Purchased Power Expense[1]	(22)	—	(22)
Other Operating Expense[1]	—	(6)	(6)
Fuel Expense	(2)	—	(2)

[1] All amounts are associated with FES.

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

[2] All amounts are associated with FES.

	For the Nine Months Ended September 30		
	Commodity Contracts	FTRs	Total
2016	(In millions)		
Unrealized Gain Recognized in:			
Other Operating Expense[1]	$2	$8	$10
Realized Gain (Loss) Reclassified to:			
Revenues[1]	$162	$5	$167
Purchased Power Expense[1]	(105)	—	(105)
Other Operating Expense[1]	—	(28)	(28)
Fuel Expense	(9)	—	(9)

[1] All amounts are associated with FES.

	For the Nine Months Ended September 30		
	Commodity Contracts	FTRs	Total
	(In millions)		
2015			
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense[2]	$81	$(17)	$64
Realized Gain (Loss) Reclassified to:			
Revenues[3]	$48	$48	$96
Purchased Power Expense[4]	(78)	—	(78)
Other Operating Expense[5]	—	(38)	(38)
Fuel Expense	(26)	—	(26)

[2] Includes $81 million for commodity contracts and $(16) million for FTRs associated with FES.
[3] Includes $48 million for commodity contracts and $46 million for FTRs associated with FES.
[4] All amounts are associated with FES.
[5] Includes $(37) 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, 2016 and 2015. Changes in the value of these instruments are deferred for future recovery from (or credit to) customers:

	For the 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, 2016	$(124)	$ 4	$(120)
Unrealized loss	(6)	—	(6)
Settlements	12	—	12
Outstanding net asset (liability) as of September 30, 2016	$(118)	$ 4	$(114)
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)

	For the 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, 2016	$(136)	$ 1	$(135)
Unrealized loss	(17)	(1)	(18)
Purchases	—	4	4
Settlements	35	—	35
Outstanding net asset (liability) as of September 30, 2016	$(118)	$ 4	$(114)
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)

10. ASSET RETIREMENT OBLIGATIONS

FirstEnergy has recognized applicable legal obligations for AROs and their associated cost primarily for nuclear power plant decommissioning, reclamation of sludge disposal ponds, closure of coal ash disposal sites, underground and above-ground storage tanks, wastewater treatment lagoons and transformers containing PCBs. In addition, FirstEnergy has recognized conditional retirement obligations, primarily for asbestos remediation.

The ARO liabilities for FES primarily relate to the decommissioning of the Beaver Valley, Davis-Besse and Perry nuclear generating facilities, which are approximately $701 million, as of September 30, 2016. FES uses an expected cash flow approach to measure the fair value of their nuclear decommissioning AROs.

FirstEnergy and FES maintain NDTs that are legally restricted for purposes of settling the nuclear decommissioning ARO. The fair values of the decommissioning trust assets as of September 30, 2016 and December 31, 2015 were as follows:

	2016	2015
	(In millions)	

FirstEnergy	$2,502	$2,282
FES	$1,542	$1,327

The following table summarizes the changes to the ARO balances during 2016:

ARO Reconciliation	FirstEnergy	FES
	(In millions)	
Balance, December 31, 2015	$1,410	$831
Liabilities settled	(25)	(17)
Liabilities incurred	4	32
Accretion	70	41
Balance, September 30, 2016	$1,459	$887

During the second quarter of 2016, in connection with NG purchasing the lessor equity interests of the remaining non-affiliated leasehold interests from an owner participant in Perry Unit 1, OE transferred the ARO (included within the FES liabilities incurred above) and related NDT assets associated with the leasehold interest to NG with the difference of $28 million credited to the common stock of FES. As of June 30, 2016, NG owns 100% of Perry Unit 1.

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. Based on an assessment of the finalized regulations, the future cost of compliance and expected timing of spend had no significant impact on FirstEnergy's or FES' existing AROs associated with CCRs. Although none are currently expected, any changes in timing and closure plan requirements in the future could materially and adversely impact FirstEnergy's and FES' AROs.

11. 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 and demand 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 $68 million, of which $38 million was incurred through September 30, 2016. 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.

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.

Pursuant to the NJBPU's March 26, 2015 final order in JCP&L's 2012 rate case proceeding directing that certain studies be completed, on July 22, 2015, the NJBPU approved the NJBPU staff's recommendation to implement such studies, which include operational and financial components. The independent consultant conducting the review issued a final report on July 27, 2016, recognizing that JCP&L is meeting the NJBPU requirements and making various operational and financial recommendations. The NJBPU issued an Order on August 24, 2016, that accepted the independent consultant’s final report and directed JCP&L, the Division of Rate Counsel, and other interested parties to address the recommendations.

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. The oral argument was held on October 25, 2016.

On April 28, 2016, JCP&L filed tariffs with the NJBPU proposing a general rate increase associated with its distribution operations that seeks to improve service and benefit customers by supporting equipment maintenance, tree trimming, and inspections of lines, poles and substations, while also compensating for other business and operating expenses. The filing requested approval to increase annual operating revenues by approximately $142.1 million based upon a hybrid test year for the twelve months ending June 30, 2016. On July 13, 2016, this matter was submitted to the Office of Administrative Law for hearing and the issuance of an Initial Decision. On September 30, 2016, JCP&L filed an update to its filing, which includes actual data for the twelve months ended June 30, 2016, requesting an increase to annual operating revenues by approximately $146.6 million. On October 19, 2016, an order was received approving the agreed upon procedural schedule. Hearings are scheduled to occur in January 2017 through March 2017. On November 2, 2016, JCP&L achieved a settlement-in-principle with all the intervening parties providing for an annual $80 million distribution revenue increase, which will take effect on January 1, 2017, subject to finalization, execution and NJBPU approval of a Stipulation of Settlement.

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. The procedural schedule was suspended while the NJBPU considered a motion on a legal issue regarding whether MAIT can be designated as a "public utility" in New Jersey. On February 24, 2016, the NJBPU issued an Order concluding that MAIT does not satisfy the “electricity distribution” element necessary for “public utility” status because MAIT would not own any electric distribution assets in New Jersey. On April 22, 2016, JCP&L and MAIT filed a supplemental petition and testimony seeking to include certain JCP&L distributions assets in the transfer to satisfy the "electricity distribution" element necessary for "public utility" status in accordance with the NJBPU’s February 24, 2016 order. In order to allow MAIT to file its formula transmission rate with an effective date of January 1, 2017, on September 8, 2016, JCP&L and MAIT submitted a letter to the NJBPU to withdraw their petition to transfer JCP&L assets into MAIT. The NJBPU administratively closed the matter on September 30, 2016. See Transfer of Transmission Assets to MAIT in FERC Matters below for further discussion of this transaction.

OHIO

On August 4, 2014, the Ohio Companies filed an application with the PUCO seeking approval of their ESP IV entitled Powering Ohio's Progress. ESP IV included a proposed Rider RRS, which would flow through to customers either charges or credits representing the net result of the price paid to FES through an eight-year FERC-jurisdictional PPA, referred to as the ESP IV PPA, against the revenues received from selling such output into the PJM markets. The Ohio Companies entered into stipulations which modified ESP IV and which included PUCO Staff as a signatory party, in addition to other signatories. On March 31, 2016, the PUCO issued an Opinion and Order adopting and approving the Ohio Companies’ stipulated ESP IV with modifications. FES and the Ohio Companies entered into the ESP IV PPA on April 1, 2016.

On January 27, 2016, certain parties filed a complaint with FERC against FES and the Ohio Companies requesting FERC review the ESP IV PPA under Section 205 of the FPA. On April 27, 2016, FERC issued an order granting the complaint, prohibiting any transactions under the ESP IV PPA pending future authorization by FERC, and directing FES to submit the ESP IV PPA for FERC review if the parties desired to transact under the agreement. FES and the Ohio Companies did not file the ESP IV PPA for FERC review but rather agreed to suspend the ESP IV PPA. FES and the Ohio Companies subsequently advised FERC of this course of action.

On April 29, 2016 and May 2, 2016, several parties, including the Ohio Companies, filed applications for rehearing on the Ohio Companies’ ESP IV with the PUCO. The Ohio Companies’ Application for Rehearing included a modified Rider RRS proposal but did not include a FERC-jurisdictional PPA. The PUCO accepted the applications for rehearing for further consideration and provided parties an opportunity to comment on the Ohio Companies’ Application for Rehearing and file an alternative proposal. PUCO Staff recommended that the PUCO deny the Ohio Companies’ modified Rider RRS proposal and recommended a new Rider DMR providing for the collection of $204 million annually (grossed up for income taxes) for three years with a possible extension for an additional two years. The Ohio Companies recommended that the PUCO approve the proposed modified Rider RRS and that a properly designed Rider DMR would be valued at $558 million annually for 8 years, and include an additional amount that recognizes the value of the economic impact of FirstEnergy maintaining its headquarters in Ohio.

Several parties subsequently filed protests and comments with FERC alleging, among other things, that the modified Rider RRS constitutes a "virtual PPA". The filings and FirstEnergy’s responses thereto are pending before FERC.

On September 6, 2016, while the applications for rehearing were still pending before the PUCO, the OCC and NOAC filed a notice of appeal with the Ohio Supreme Court appealing various PUCO and Attorney Examiner Entries on the parties’ applications for rehearing. On September 16, 2016, the Ohio Companies intervened and filed a motion to dismiss the appeal. The appeal remains pending before the Ohio Supreme Court.

On October 12, 2016, the PUCO issued an opinion and order ruling on the parties’ applications for rehearing and further modified ESP IV. The PUCO order denied the Ohio Companies’ modified Rider RRS proposal, and instead approved a Rider DMR proposed by PUCO Staff, with modifications.

As a result of the stipulations, the PUCO’s March 31, 2016 Opinion and Order and the PUCO’s October 12, 2016 order, the material terms of ESP IV include:

- An eight-year term (June 1, 2016 - May 31, 2024).
- The Rider DMR which provides for the Ohio Companies to collect $132.5 million annually for three years, with the possibility of a two-year extension. The Rider DMR will be grossed up for taxes, resulting in an approved amount of approximately $204 million annually. Revenues from the Rider DMR will be excluded from the significantly excessive earnings test for the initial three-year term but the exclusion will be reconsidered upon application for a potential two-year extension.

- Three conditions for continued recovery under the Rider DMR: (1) retention of the corporate headquarters and nexus of operations in Akron, Ohio; (2) no change in control of the Ohio Companies; and (3) a demonstration of sufficient progress in the implementation of grid modernization programs approved by the PUCO.
- No restrictions on the Ohio Companies' use of funds collected under the Rider DMR. However, the PUCO directed the PUCO Staff to periodically review how the Ohio Companies and FE use the funds to ensure the funds are used, directly or indirectly, in support of grid modernization. Uses of funds to indirectly support grid modernization could include, e.g., reducing outstanding pension obligations or reducing debt.
- Continuation of a base distribution rate freeze through May 31, 2024.
- Continuation of the supply of power to non-shopping customers at a market-based price set through an auction process.
- Continuation of Rider DCR with increased revenue caps of approximately $30 million per year from June 1, 2016 through May 31, 2019; $20 million per year from June 1, 2019 through May 31, 2022; and $15 million per year from June 1, 2022 through May 31, 2024 that supports continued investment related to the distribution system for the benefit of customers.
- Collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs.
- Continuation of 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.
- Potential procurement of 100 MW of new Ohio wind or solar resources subject to a demonstrated need to procure new renewable energy resources as part of a strategy to further diversify Ohio's energy portfolio.

- An agreement to file a case with the PUCO by April 3, 2017, seeking to transition to decoupled base rates for residential customers.
- An agreement to file a Grid Modernization Business Plan for PUCO consideration and approval (which filing was made on February 29, 2016).
- A goal across FirstEnergy to reduce CO_2 emissions by 90% below 2005 levels by 2045.
- A contribution of $3 million per year ($24 million over the eight-year term) to fund energy conservation programs, economic development and job retention in the Ohio Companies service territory.
- Contributions of $2.4 million per year ($19 million over the eight-year term) to fund a fuel-fund in each of the Ohio Companies service territories to assist low-income customers.
- A contribution of $1 million per year ($8 million over the eight-year term) to establish a Customer Advisory Council to ensure preservation and growth of the competitive market in Ohio.

Finally, on March 21, 2016, a number of generation owners filed with FERC a complaint against PJM requesting that FERC expand the MOPR in the PJM Tariff to prevent the alleged artificial suppression of prices in the PJM capacity markets by state-subsidized generation, in particular alleged price suppression that could result from the ESP IV PPA and other similar agreements. The complaint requested that FERC direct PJM to initiate a stakeholder process to develop a long-term MOPR reform for existing resources that receive out-of-market revenue. This proceeding remains pending before FERC.

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 legislative amendments to the energy efficiency standards discussed below. 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 legislative amendments to the peak demand reduction standards discussed below.

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 the energy policy of the state. Legislation was introduced to address issues raised in the Energy Mandates Study Committee report, namely SB320 and HB554. SB320 proposes to freeze energy efficiency and renewable energy requirements for an additional four years at 2014 levels, as well as addressing net metering issues. HB554 proposes to freeze energy efficiency and renewable energy requirements through 2027 at 2014 levels.

On September 24, 2014, the Ohio Companies filed an amendment to their energy efficiency 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 and the matter remains pending before the PUCO.

On April 15, 2016, the Ohio Companies filed an application for approval of their three-year energy efficiency portfolio plans for the period from January 1, 2017 through December 31, 2019. The plans as proposed comply with benchmarks contemplated by SB310 and provisions of the ESP IV, and include a portfolio of energy efficiency programs targeted to a variety of customer segments, including residential customers, low income customers, small commercial customers, large commercial and industrial customers and governmental entities. The Ohio Companies anticipate the cost of the plans will be approximately $323 million over the life of the portfolio plans and such costs are expected to be recovered through the Ohio Companies’ existing rate mechanisms. The hearing is scheduled for November 21-23, 2016.

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 was denied. On August 9, 2016, upon a Joint Application for Dismissal filed by the Ohio Companies, PUCO and the ELPC, the Ohio Supreme Court dismissed the appeal.

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 legislative amendments discussed above, 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 certain purchases arising from one auction and directed 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. On November 18, 2015, the PUCO ruled that on a going-forward basis, pass-through clauses may not be included in fixed-price contracts for all customer classes. On December 18, 2015, FES filed an Application for Rehearing seeking to change the ruling or have it only apply to residential and small commercial customers. On January 13, 2016, the PUCO granted reconsideration for further consideration of the matters specified in the applications for rehearing.

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.

Following the expiration of the current DSPs, the Pennsylvania Companies will operate under new DSPs for the June 1, 2017 through May 31, 2019 delivery period, which would provide for the competitive procurement of generation supply for customers who do not choose an alternative EGS or for customers of alternative EGSs that fail to provide the contracted service. Under the programs, the supply would be provided by wholesale suppliers through a mix of 12 and 24-month energy contracts, as well as one RFP for 2-year SREC contracts for ME, PN and Penn. In addition, the plan includes modifications to the Pennsylvania Companies’ existing POR programs in order to reduce the level of uncollectible expense the Pennsylvania Companies experience associated with alternative EGS charges.

Pursuant to Pennsylvania's EE&C legislation (Act 129 of 2008) and PPUC orders, Pennsylvania EDCs implement energy efficiency and peak demand reduction programs. The Pennsylvania Companies' Phase II EE&C Plans were effective through May 31, 2016. Total Phase II costs of these plans were expected to be approximately $175 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' Phase III EE&C plans for the June 2016 through May 2021 period, which were approved in March 2016, are designed to achieve the targets established in the PPUC's Phase III Final Implementation Order without recovery to implement the 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. On February 11, 2016, the PPUC approved the Pennsylvania Companies' LTIIPs. On February 16, 2016, the Pennsylvania Companies filed DSIC riders for PPUC approval for quarterly cost recovery associated with the capital projects approved in the LTIIPs. On June 9, 2016, the PPUC approved the Pennsylvania Companies’ DSIC riders to be effective July 1, 2016, subject to hearings and refund or reallocation among customers.

On April 28, 2016, each of the Pennsylvania Companies filed tariffs with the PPUC proposing general rate increases associated with their distribution operations that will benefit customers by modernizing the grid with smart technologies, increasing vegetation management activities, and continuing other customer service enhancements. The filings request approval to increase annual operating revenues by approximately $140.2 million at ME, $158.8 million at PN, $42.0 million at Penn, and $98.2 million at WP, based upon fully projected future test years for the twelve months ending December 31, 2017 at each of the Pennsylvania Companies. As a result of the enactment of Act 40 of 2016 that terminated the practice of making a CTA when calculating a utility’s federal income taxes for ratemaking purposes, the Pennsylvania Companies submitted supplemental testimony on July 7, 2016, that quantified the value of the elimination of the CTA and outlined their plan for investing 50 percent of that amount in rate base eligible equipment as required by the new law. Formal settlement agreements for each of the Pennsylvania Companies were filed on October 14, 2016, which provide increases in annual operating revenues of approximately $96 million at ME, $100 million at PN, $29 million at Penn, and $66 million at WP, and are subject to PPUC approval. One item related to the calculation of DSIC rates was reserved for briefing, with briefs filed by two parties. The proposed new rates are expected to take effect in January 2017 pending regulatory approval, which is expected no later than January 26, 2017.

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. On March 4, 2016, a Joint Petition for Full Settlement was submitted to the PPUC for consideration and approval. On April 18, 2016, the ALJs issued an Initial Decision approving the Joint Petition for Full Settlement without modifications. On July 21, 2016, the PPUC adopted a Motion approving the Joint Petition for Full Settlement with minor modifications. On August 24, 2016, the PPUC issued a Final Order approving the Joint Settlement consistent with the July 21, 2016 Motion. See Transfer of Transmission Assets to MAIT in FERC Matters below for further discussion of this transaction.

WEST VIRGINIA

MP and PE provide electric service to all customers through traditional cost-based, regulated utility ratemaking. MP and PE recover net power supply costs, including fuel costs, purchased power costs and related expenses, net of related market sales revenue through the ENEC. MP's and PE's ENEC rate is updated annually.

MP and PE filed with the WVPSC on March 31, 2016 their Phase II energy efficiency program proposal for approval. MP and PE are proposing three energy efficiency programs to meet their Phase II requirement of energy efficiency reductions of 0.5% of 2013 distribution sales for the January 1, 2017 through May 31, 2018 period, as agreed to by MP and PE, and approved by the WVPSC in the 2012 proceeding approving the transfer of ownership of Harrison Power Station to MP. The costs for the program are expected to be $10.4 million and will be eligible for recovery through the existing energy efficiency rider which is reviewed in the fuel (ENEC) case each year. A unanimous settlement was reached by the parties on all issues and presented to the WVPSC on August 18, 2016. An order approving the settlement in full without modification was issued by the WVPSC on September 23, 2016. Under the order, the programs may begin as of the date of such order, but no later than January 1, 2017.

The Staff of the WVPSC and the Consumer Advocate Division filed a Show Cause petition on August 5, 2016, requesting the WVPSC order MP and PE to file and implement RFPs for all future capacity and energy requirements above 100 MWs and that they comply with an RFP settlement provision from the Harrison asset acquisition. MP and PE filed a timely response to the petition arguing for dismissal on September 7, 2016. On October 17, 2016, the WVPSC denied the petition filed by the Staff of the WVPSC and the Consumer Advocate Division and dismissed the case.

On August 16, 2016, MP and PE filed their annual ENEC case proposing an approximate $65 million annual increase in rates effective January 1, 2017, which is a 4.7% overall increase over existing rates. The $65 million increase is comprised of $119 million under-recovered balance as of June 30, 2016, and a projected $54 million over-recovery for the 2017 rate effective period. A hearing has been set for November 9 and 10, 2016 with an order expected to be issued in the fourth quarter of 2016.

On August 22, 2016, MP and PE filed an application for approval of a modernization and improvement plan for coal-fired boilers at electric power plants and cost-recovery surcharge proposing an approximate $6.9 million annual increase in rates proposed to be effective May 1, 2017, which is a 0.5% overall increase over existing rates. The filing is in response to recent legislation by the West Virginia Legislature session permitting accelerated recovery of costs related to modernizing and improving coal-fired boilers, including costs related to meeting environmental requirements and reducing emissions. The filing was supplemented on September 28, 2016, to add two additional projects, resulting in an approximate $7.4 million annual increase in rates. The Staff of the WVPSC has filed a motion to dismiss the case arguing the new statute was not meant to recover these types of projects, but the WVPSC has set the case for hearing for February 21-23, 2017.

On December 30, 2015, MP filed an IRP identifying a capacity shortfall starting in 2016 and exceeding 700 MW by 2020 and 850 MW by 2027. On June 3, 2016, the WVPSC accepted the IRP finding that IRPs are informational and that it must not approve or disapprove the IRP. MP Plans to issue a RFP to address its generation shortfall identified in the IRP by the end of the year.

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

Ohio ESP IV PPA

For information regarding matters before FERC related to the ESP IV PPA between FES and the Ohio Companies, see “Regulatory Matters - Ohio” above.

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. On June 15, 2016 various parties, including ATSI and the Utilities, filed a settlement agreement at FERC agreeing to apply a combined usage based/socialization approach to cost allocation for charges to transmission customers in the PJM region for transmission projects operating at or above 500 kV. Certain parties in the proceeding did not agree to the settlement and filed protests to the settlement seeking, among other issues, to strike certain of the evidence advanced by FirstEnergy and certain of the other settling parties in support of the settlement, as well as provided further comments in opposition to the settlement. The PJM TOs responded to the protesting parties' various pleadings and motions. The settlement is pending before FERC.

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 appealed these rulings to the U.S. Court of Appeals for the D.C. Circuit which, in a July 1, 2016 opinion, ruled that the PJM transmission owners failed to preserve their arguments in the legal proceedings before FERC and, on that basis, denied the appeal. In a related case brought by the Southwest Power Pool transmission owners and issued on the same day, the court ruled that the Mobile-Sierra standard does not protect transmission owners’ rights of first refusal that may be provided for in RTO tariffs because, according to the court, the tariff language is designed to block competition. The Mobile-Sierra standard presumes that rates negotiated by private parties at arm’s length are just and reasonable and prohibits FERC from modifying such rates unless the public interest requires.

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 transfer to PJM. 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. On March 17, 2016, FERC denied FirstEnergy's request for rehearing of FERC's earlier order rejecting the settlement agreement and affirmed its prior ruling that ATSI must submit the cost/benefit analysis.

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. On October 29, 2015, FERC issued an order finding that ATSI and the ATSI zone do not have to pay MISO MVP charges for the Michigan Thumb transmission project. MISO and the MISO TOs filed a request for rehearing, which FERC denied on May 19, 2016. On July 15, 2016, the MISO TOs filed an appeal of FERC's orders with the Sixth Circuit. FirstEnergy intervened in the proceedings and intends to participate in the appeal. 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 July 13, 2016, FERC issued its order finding it appropriate for MISO to assess an MVP usage charge for transmission exports from MISO to PJM. Various parties, including FirstEnergy and the PJM TOs, requested rehearing or clarification of FERC’s order. These parties' request for rehearing remains pending before FERC.

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 the proceedings that address the remaining open issues related to costs for the "Michigan Thumb" transmission project and "legacy RTEP" transmission projects cannot be predicted at this time.

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 law; (iv) MAIT's participation in FE's regulated companies' money pool; and (v) certain affiliated interest agreements. As initially proposed, it was expected that JCP&L, ME, and PN would contribute their transmission assets at net book value and an allocated portion of goodwill in a tax-free exchange to MAIT, which would 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. FERC approved the transaction on February 18, 2016. On August 24, 2016, the PPUC issued a Final Order approving the transaction. In order to allow MAIT to file its formula transmission rate with an effective date of January 1, 2017, on September 8, 2016, JCP&L and MAIT submitted a letter to the NJBPU to withdraw their petition to transfer JCP&L assets to MAIT. The NJBPU administratively closed the matter on September 30, 2016. See New Jersey and Pennsylvania in State Regulation above for further discussion of this transaction.

On October 14 and 28, 2016, MAIT submitted applications to FERC requesting authorization to issue equity, short-term debt, and long-term debt. MAIT intends to issue membership interests to FET, PN, and ME in exchange for their respective cash and asset contributions. MAIT is expected to issue short-term debt and participate in the FirstEnergy Utility Money Pool for working capital, to fund day-to-day operations, and for other general corporate purposes. Over the long-term, MAIT is expected to issue long-term debt to support capital investment and to establish an actual capital structure for ratemaking purposes. On October 28, 2016, MAIT submitted an application to FERC requesting authorization to implement a formula transmission rate to recover and earn a return on transmission costs effective January 1, 2017. On October 28, 2016, MAIT and PJM submitted joint applications to FERC requesting authorization for (i) ME and PN to withdraw from the PJM Consolidated Transmission Owners Agreement as TOs, and (ii) MAIT to become a participating PJM TO. Acceptance of MAIT as a PJM TO would grant PJM functional control over MAIT’s transmission assets, and would permit PJM to implement MAIT’s formula rate on MAIT’s behalf.

JCP&L Transmission Formula Rate

Given that JCP&L will not be transferring its transmission assets to MAIT, there is a need for JCP&L to update its transmission rate. Accordingly, on October 28, 2016, JCP&L submitted an application to FERC requesting authorization to implement a formula transmission rate to recover and earn a return on transmission costs effective January 1, 2017.

California Claims Litigation

Since 2002, AE Supply has been involved in litigation and claims based on its power sales to the California Energy Resource Scheduling division of the CDWR during 2001-2003. This litigation and claims are related to litigation and claims advanced by the California Attorney General and certain California utilities regarding alleged market manipulation of the wholesale energy markets in California during the 2000-2001 period. AE Supply negotiated a settlement with the California Attorney General and the California utilities and, on August 24, 2016, filed the settlement agreement for FERC approval. The settlement calls for AE Supply to pay, without admission of any liability, $3.6 million in settlement in principle of all remaining claims that are based on AE Supply’s power sales in the western energy markets during the 2001-2003 time period. On October 27, 2016 FERC approved this settlement.

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, 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. On September 14, 2015, the ALJ issued his initial decision, disallowing recovery of certain costs. The initial decision and exceptions thereto remain 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, and on March 3, 2015, FERC issued Opinion No. 531-B affirming its prior rulings. Appeals of Opinion Nos. 531, 531-A and 531-B are pending before the U.S. Court of Appeals for the D.C. Circuit.

MISO Capacity Portability

On June 11, 2012, in response to certain arguments advanced by MISO, FERC requested comments regarding whether existing rules on transfer capability act as barriers to the delivery of capacity between MISO and PJM. FirstEnergy and other parties submitted filings arguing that MISO's concerns largely are without foundation, FERC did not mandate a solution in response to MISO's concerns. At FERC's direction, in May, 2015, PJM, MISO, and their respective independent market monitors provided additional information on their various joint issues surrounding the PJM/MISO seam to assist 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 remain 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.

12. 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, 2016, FirstEnergy's outstanding guarantees and other assurances aggregated approximately $3.4 billion, consisting of parental guarantees ($584 million), subsidiaries' guarantees ($2.0 billion), other guarantees ($300 million) and other assurances ($504 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, 2016, FES has posted collateral of $193 million and AE Supply has posted collateral of $4 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.

As a result of the downgrades by Moody's and S&P on July 29, 2016 and August 1, 2016, CES posted additional collateral of $53 million. Additionally, on November 4, 2016, Moody's and S&P further downgraded FES. Given the downgrades, CES has further potential collateral posting obligations totaling $81 million for which counterparties have not exercised their right to require CES to post collateral. Subsequent to the occurrence of a senior unsecured credit rating downgrade below S&P's and Moody's current ratings, or a “material adverse event,” the immediate posting of collateral or accelerated payments may be required of FirstEnergy. The following table discloses the additional credit contingent contractual obligations that may be required under certain events as of November 4, 2016:

Potential Collateral Obligations	CES	Regulated	Total
	(in millions)		
Contractual Obligations for Additional Collateral			
At Current Credit Rating	$81	$ —	$81
Upon Further Downgrade	—	48	48
Upon Material Adverse Event	10	—	10
Surety Bonds (Collateralized Amount)	264	96	360
Total Exposure from Contractual Obligations	$355	$ 144	$499

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, 2016, neither FES nor AE Supply had any collateral posted with their affiliates.

OTHER COMMITMENTS AND CONTINGENCIES

FE 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 FE, Signal Peak, Global Rail, Global Mining Group, LLC and Global Coal Sales Group, LLC, each being a direct or indirect subsidiary of Global Holding, 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.

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. The U.S. Court of Appeals for the D.C. Circuit ordered the EPA on July 28, 2015, to reconsider the CSAPR 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 CSAPR, but questioning whether EPA required upwind states to reduce emissions by more than their contribution to air pollution in downwind states. EPA issued a CSAPR update rule on September 7, 2016, reducing summertime NOx emissions from power plants in 22 states in the eastern U.S., including Ohio, Pennsylvania and West Virginia, beginning in 2017. Depending on how the EPA and the states implement CSAPR, the future cost of compliance may be material 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 EPA will designate those 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 material and changes to FirstEnergy’s and FES’ operations may result. In August 2016, the State of Delaware filed a CAA Section 126 petition with the EPA alleging that the Harrison generating facility's NOx emissions significantly contribute to Delaware's inability to attain the ozone NAAQS. The petition seeks a short term NOx emission rate limit of 0.125 lb/mmBTU over an averaging period of no more than 24 hours. On September 27, 2016, EPA extended the time frame for acting on the CAA Section 126 petition by six months to April 7, 2017. FirstEnergy is unable to predict the outcome of this matter or estimate the loss or range of loss.

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. FirstEnergy's total capital cost for compliance (over the 2012 to 2018 time period) is currently expected to be approximately $345 million (CES segment of $168 million and Regulated Distribution segment of $177 million), of which $267 million has been spent through September 30, 2016 ($117 million at CES and $150 million at Regulated Distribution).

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 event 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, all plants covered by this contract 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 under the contract through 2025. On May 31, 2016, the parties agreed to a stipulation that if FG’s force majeure defense is determined to be wholly or partially invalid, liquidated damages are the sole remedy available to BNSF and CSX. The arbitration panel has determined to consolidate the claims with a liability hearing scheduled to begin on November 28, 2016, and, if necessary, a damages hearing scheduled to begin on May 8, 2017. The decision on liability is expected to be issued within sixty days from the end of the liability hearing proceedings, which are scheduled to conclude February 24, 2017. 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. FG intends to vigorously assert its 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. Refer to the Strategic Review of Competitive Operations section of Note 1, Organization and Basis of Presentation, for possible actions that may be taken by FES in the event of an adverse outcome, including, without limitation, seeking protection under the bankruptcy laws. 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 FG fails 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 to the deactivated plant, 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, FG paid approximately $70 million in the aggregate in liquidated damages to settle delivery shortfalls in 2014 related to its deactivated plants, which approximated full liquidated damages under the agreements for such year related to the plant deactivations. Liquidated damages for the period 2015-2025 remain in dispute.

As to a specific coal supply agreement, AE Supply has asserted termination rights effective in 2015. In response to notification of the termination, the coal supplier commenced litigation alleging AE Supply does not have sufficient justification to terminate the agreement. AE Supply has filed an answer denying any liability related to the termination. This matter is currently in the discovery phase of litigation and no trial date has been established. There are approximately 5.5 million tons remaining under the contract for delivery. At this time, AE Supply 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, March 27, 2013 and October 18, 2017, 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 loss or range of loss.

Climate Change

FirstEnergy has established a goal to reduce CO_2 emissions by 90% below 2005 levels by 2045. 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

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GHGs. Additional policies reducing GHG emissions, such as demand reduction programs, renewable portfolio standards and renewable subsidies have been implemented across the nation.

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 (which have been stayed by the U.S. Supreme Court), 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 two-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. Numerous states and private parties filed appeals and motions to stay the CPP with the U.S. Court of Appeals for the D.C. Circuit in October 2015. On January 21, 2015, a panel of the D.C. Circuit denied the motions for stay and set an expedited schedule for briefing and argument. On February 9, 2016, the U.S. Supreme Court stayed the rule during the pendency of the challenges to the D.C. Circuit and U.S. Supreme Court. Depending on the outcome of further appeals and how any final rules are ultimately implemented, the future cost of compliance may be material.

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. 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 and joined in adopting the agreement reached on December 12, 2015 at the United Nations Framework Convention on Climate Change meetings in Paris. The Paris Agreement was ratified by the requisite number of countries (i.e. at least 55 countries representing at least 55% of global GHG emissions) in October 2016 and its non-binding obligations to limit global warming to well below two degrees Celsius are effective on November 4, 2016. 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 material 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 capital costs of compliance with these standards may be substantial.

On September 30, 2015, the EPA finalized new, more stringent effluent limits for the Steam Electric Power Generating category (40 CFR Part 423) 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 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. Based on an assessment of the finalized regulations, the future cost of compliance and expected timing of spend had no significant impact on FirstEnergy's or FES' existing AROs associated with CCRs. Although none are currently expected, any changes in timing and closure plan requirements in the future could materially and adversely impact FirstEnergy's and FES' AROs.

Pursuant to a 2013 consent decree, PA DEP issued a 2014 permit for the Little Blue Run CCR impoundment requiring the Bruce Mansfield plant to cease disposal of CCRs by December 31, 2016 and FG to provide bonding for 45 years of closure and post-closure activities and to complete closure within a 12-year period, but authorizing FG 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 disposal of CCRs following December 31, 2016 and expects beneficial reuse and disposal options will be sufficient for the ongoing operation of the plant. 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 Notices of Appeal with the Pennsylvania Environmental Hearing Board challenging the renewal, reissuance and modification of the permit for the Hatfield’s Ferry CCR 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, 2016 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 $121 million have been accrued through September 30, 2016. Included in the total are accrued liabilities of approximately $89 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 loss 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, 2016, FirstEnergy had approximately $2.5 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 guarantees in support of the decommissioning of the spent fuel storage facilities located at the nuclear facilities. However, as FES no longer maintains investment grade credit ratings from either S&P or Moody’s, NG plans to fund a supplemental trust in lieu of a parental guarantee that would be required to support the decommissioning of the spent fuel storage facilities. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guarantees, 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. On December 8, 2015, the NRC renewed the operating license for Davis-Besse, which is now authorized to continue operation through April 22, 2037. Prior to that decision, the NRC Commissioners denied an intervenor's request 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 intervened in that proceeding. On September 21, 2016, the U.S. Court of Appeals for the DC Circuit granted the intervenor’s unopposed motion and dismissed this case.

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. FENOC plans to submit a license amendment application to the NRC related to the laminar cracking in 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 11, 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.

13. SUPPLEMENTAL GUARANTOR INFORMATION

In 2007, FG completed a sale and leaseback transaction for a 93.83% undivided interest in Bruce Mansfield Unit 1. FG's parent company 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 FG or its parent company, but the notes are secured by, among other things, each lessor trust's undivided interest in Unit 1, rights and interests under the applicable lease and rights and interests under other related agreements, including FES' lease guaranty. This transaction is classified as an operating lease for FES and FirstEnergy and as a financing lease for FG.

The Condensed Consolidating Statements of Income (Loss) and Comprehensive Income (Loss) for the three and nine months ended September 30, 2016 and 2015, Condensed Consolidating Balance Sheets as of September 30, 2016 and December 31, 2015, and Condensed Consolidating Statements of Cash Flows for the nine months ended September 30, 2016 and 2015, for the parent and guarantor and non-guarantor subsidiaries are presented below. These statements are provided as FG's parent company 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 the parent company using the equity method. Results of operations for FG and NG are, therefore, reflected in their parent company's investment accounts and earnings as if operating lease treatment was achieved. The principal elimination entries eliminate investments in subsidiaries and intercompany balances and transactions and the entries required to reflect operating lease treatment associated with the 2007 Bruce Mansfield Unit 1 sale and leaseback transaction.

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

For the Three Months Ended September 30, 2016	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME					
REVENUES	$1,065	$494	$400	$ (859)	$ 1,100
OPERATING EXPENSES:					
Fuel	—	149	53	—	202
Purchased power from affiliates	1,011	—	39	(859)	191
Purchased power from non-affiliates	186	—	—	—	186
Other operating expenses	95	61	149	11	316
Provision for depreciation	4	28	51	—	83
General taxes	8	7	6	—	21
Total operating expenses	1,304	245	298	(848)	999
OPERATING INCOME (LOSS)	(239)	249	102	(11)	101
OTHER INCOME (EXPENSE):					
Investment income, including net income from equity investees	224	8	28	(236)	24
Miscellaneous income	—	1	—	—	1
Interest expense — affiliates	(13)	(3)	(2)	15	(3)
Interest expense — other	(14)	(27)	(9)	14	(36)
Capitalized interest	—	3	6	—	9
Total other income (expense)	197	(18)	23	(207)	(5)
INCOME (LOSS) BEFORE INCOME TAXES (BENEFITS)	(42)	231	125	(218)	96
INCOME TAXES (BENEFITS)	(82)	87	49	2	56
NET INCOME	$40	$144	$76	$ (220)	$ 40
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$40	$144	$76	$ (220)	$ 40
OTHER COMPREHENSIVE INCOME (LOSS):					
Pension and OPEB prior service costs	(3)	(3)	—	3	(3)
Amortized gains on derivative hedges	1	—	—	—	1
Change in unrealized gains on available-for-sale securities	5	—	5	(5)	5
Other comprehensive income (loss)	3	(3)	5	(2)	3
Income taxes (benefits) on other comprehensive income (loss)	1	(1)	2	(1)	1
Other comprehensive income (loss), net of tax	2	(2)	3	(1)	2
COMPREHENSIVE INCOME	$42	$142	$79	$ (221)	$ 42

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

For the Nine Months Ended September 30, 2016	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF INCOME (LOSS)					
REVENUES	$3,281	$1,309	$1,404	$ (2,593)	$ 3,401
OPERATING EXPENSES:					
Fuel	—	449	146	—	595
Purchased power from affiliates	2,888	—	145	(2,593)	440
Purchased power from non-affiliates	829	—	—	—	829
Other operating expenses	218	220	450	37	925
Provision for depreciation	10	91	151	(2)	250
General taxes	23	23	20	—	66
Impairment of assets	23	517	—	—	540
Total operating expenses	3,991	1,300	912	(2,558)	3,645
OPERATING INCOME (LOSS)	(710)	9	492	(35)	(244)
OTHER INCOME (EXPENSE):					
Investment income, including net income (loss) from equity investees	310	21	67	(342)	56
Miscellaneous income	3	1	—	—	4
Interest expense — affiliates	(34)	(7)	(4)	39	(6)
Interest expense — other	(40)	(79)	(33)	43	(109)
Capitalized interest	—	7	20	—	27
Total other income (expense)	239	(57)	50	(260)	(28)
INCOME (LOSS) BEFORE INCOME TAXES (BENEFITS)	(471)	(48)	542	(295)	(272)
INCOME TAXES (BENEFITS)	(204)	(1)	196	4	(5)
NET INCOME (LOSS)	$(267)	$(47)	$346	$ (299)	$ (267)
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)					
NET INCOME (LOSS)	$(267)	$(47)	$346	$ (299)	$ (267)
OTHER COMPREHENSIVE INCOME (LOSS):					
Pensions and OPEB prior service costs	(10)	(10)	—	10	(10)
Amortized gains on derivative hedges	—	—	—	—	—
Change in unrealized gains on available-for-sale securities	61	—	60	(60)	61
Other comprehensive income (loss)	51	(10)	60	(50)	51
Income taxes (benefits) on other comprehensive income (loss)	20	(4)	23	(19)	20
Other comprehensive income (loss), net of tax	31	(6)	37	(31)	31

COMPREHENSIVE INCOME (LOSS)	$(236)	$(53)	$383	$ (330)	$ (236)

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FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

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):					
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 gains on derivative hedges	—	—	—	—	—
Change in unrealized gains 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

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FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

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	300	208	452	36	996
Provision for depreciation	8	92	142	(2)	240
General taxes	36	23	19	—	78
Impairment of assets	16	—	—	—	16
Total operating expenses	4,353	846	967	(2,584)	3,582
OPERATING INCOME (LOSS)	(654)	413	527	(34)	252
OTHER INCOME (EXPENSE):					
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) BEFORE INCOME TAXES (BENEFITS)	(162)	349	508	(535)	160
INCOME TAXES (BENEFITS)	(258)	131	187	4	64
NET INCOME	$96	$218	$321	$ (539)	$ 96
STATEMENTS OF COMPREHENSIVE INCOME					
NET INCOME	$96	$218	$321	$ (539)	$ 96
OTHER COMPREHENSIVE LOSS					
Pension and OPEB prior service costs	(12)	(11)	—	11	(12)
Amortized gains on derivative hedges	(2)	—	—	—	(2)
Change in unrealized gains 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

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS

As of September 30, 2016	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$—	$2	$—	$ —	$ 2
Receivables-					
Customers	225	—	—	—	225
Affiliated companies	356	351	267	(492)	482
Other	21	4	30	—	55
Notes receivable from affiliated companies	494	1,501	1,133	(3,102)	26
Materials and supplies	38	153	212	—	403
Derivatives	146	—	—	—	146
Collateral	85	—	—	—	85
Prepayments and other	57	14	1	—	72
	1,422	2,025	1,643	(3,594)	1,496
PROPERTY, PLANT AND EQUIPMENT:					
In service	121	5,683	8,674	(378)	14,100
Less — Accumulated provision for depreciation	49	1,915	4,050	(192)	5,822
	72	3,768	4,624	(186)	8,278
Construction work in progress	3	287	758	—	1,048
	75	4,055	5,382	(186)	9,326
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,542	—	1,542
Investment in affiliated companies	7,826	—	—	(7,826)	—
Other	—	10	—	—	10
	7,826	10	1,542	(7,826)	1,552
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	279	27	—	(306)	—
Customer intangibles	11	—	—	—	11
Property taxes	—	3	7	—	10
Derivatives	98	—	—	—	98
Other	29	333	—	12	374
	417	363	7	(294)	493
	$9,740	$6,453	$8,574	$ (11,900)	$ 12,867
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$—	$199	$8	$ (25)	$ 182
Short-term borrowings-					
Affiliated companies	2,723	480	—	(3,102)	101
Accounts payable-					
Affiliated companies	597	165	180	(549)	393
Other	18	71	—	—	89
Accrued taxes	31	28	51	(38)	72
Derivatives	88	1	—	—	89

Other	66	71	12	33	182
	3,523	1,015	251	(3,681)	1,108
CAPITALIZATION:					
Total equity	5,409	2,897	4,893	(7,790)	5,409
Long-term debt and other long-term obligations	691	2,108	1,120	(1,104)	2,815
	6,100	5,005	6,013	(8,894)	8,224
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	765	765
Accumulated deferred income taxes	7	—	817	(90)	734
Retirement benefits	25	194	—	—	219
Asset retirement obligations	—	186	701	—	887
Derivatives	45	5	—	—	50
Other	40	48	792	—	880
	117	433	2,310	675	3,535
	$9,740	$6,453	$8,574	$ (11,900)	$ 12,867

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS

As of December 31, 2015	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$—	$2	$—	$ —	$ 2
Receivables-					
Customers	275	—	—	—	275
Affiliated companies	433	403	461	(846)	451
Other	36	4	19	—	59
Notes receivable from affiliated companies	406	1,210	805	(2,410)	11
Materials and supplies	53	204	213	—	470
Derivatives	154	—	—	—	154
Collateral	70	—	—	—	70
Prepayments and other	48	18	—	—	66
	1,475	1,841	1,498	(3,256)	1,558
PROPERTY, PLANT AND EQUIPMENT:					
In service	93	6,367	8,233	(382)	14,311
Less — Accumulated provision for depreciation	40	2,144	3,775	(194)	5,765
	53	4,223	4,458	(188)	8,546
Construction work in progress	30	249	878	—	1,157
	83	4,472	5,336	(188)	9,703
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,327	—	1,327
Investment in affiliated companies	7,452	—	—	(7,452)	—
Other	—	10	—	—	10
	7,452	10	1,327	(7,452)	1,337
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	300	16	—	(316)	—
Customer intangibles	61	—	—	—	61
Goodwill	23	—	—	—	23
Property taxes	—	12	28	—	40
Derivatives	79	—	—	—	79
Other	29	312	14	12	367
	492	340	42	(304)	570
	$9,502	$6,663	$8,203	$ (11,200)	$ 13,168
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$—	$229	$308	$ (25)	$ 512
Short-term borrowings-					
Affiliated companies	2,021	389	—	(2,410)	—
Other	—	8	—	—	8
Accounts payable-					
Affiliated companies	884	146	368	(856)	542
Other	21	118	—	—	139

Accrued taxes	7	93	62	(86)	76
Derivatives	103	1	—	—	104
Other	66	61	9	45	181
	3,102	1,045	747	(3,332)	1,562
CAPITALIZATION:					
Total equity	5,605	2,944	4,476	(7,420)	5,605
Long-term debt and other long-term obligations	690	2,116	840	(1,136)	2,510
	6,295	5,060	5,316	(8,556)	8,115
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	791	791
Accumulated deferred income taxes	6	—	697	(103)	600
Retirement benefits	27	305	—	—	332
Asset retirement obligations	—	191	640	—	831
Derivatives	37	1	—	—	38
Other	35	61	803	—	899
	105	558	2,140	688	3,491
	$9,502	$6,663	$8,203	$ (11,200)	$ 13,168

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FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Nine Months Ended September 30, 2016	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$(605)	$401	$820	$ (12)	$ 604
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Long-term debt	—	186	285	—	471
Short-term borrowings, net	701	92	—	(692)	101
Redemptions and Repayments-					
Long-term debt	—	(211)	(304)	12	(503)
Other	—	(5)	(2)	—	(7)
Net cash provided from (used for) financing activities	701	62	(21)	(680)	62
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(28)	(171)	(233)	—	(432)
Nuclear fuel	—	—	(195)	—	(195)
Sales of investment securities held in trusts	—	—	576	—	576
Purchases of investment securities held in trusts	—	—	(619)	—	(619)
Cash investments	10	—	—	—	10
Loans to affiliated companies, net	(87)	(292)	(328)	692	(15)
Other	9	—	—	—	9
Net cash used for investing activities	(96)	(463)	(799)	692	(666)
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

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FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

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)
Sales of investment securities held in trusts	—	—	503	—	503
Purchases of investment securities held in trusts	—	—	(546)	—	(546)
Loans to affiliated companies, net	(45)	(302)	(475)	822	—
Cash Investments	(10)	—	—	—	(10)
Other	10	6	—	—	16
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

14. 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 controls 3,790 MWs of regulated electric generation capacity located primarily in West Virginia, Virginia and New Jersey. The segment's results reflect the commodity costs of securing electric generation and the deferral and amortization of certain fuel costs.

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). This segment also includes the regulatory asset associated with the abandoned PATH project. The segment's revenues are primarily derived from forward-looking rates at ATSI and TrAIL, as well as fixed rates at certain of FirstEnergy’s utilities. Both the forward-looking and fixed rates recover costs and provide a return on transmission capital investment. Under the forward-looking rates, each of ATSI's and TrAIL’s revenue requirement is updated annually based on a projected rate base and projected costs, which is subject to annual true-up based on actual costs. Except for the recovery of the PATH abandoned project regulatory asset, the segment's revenues are primarily from transmission services provided to LSEs pursuant to the PJM Tariff. 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. As of September 30, 2016, this business segment controlled 13,162 MWs of electric generating 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, as well as other operating and maintenance costs, including costs incurred by FENOC.

Corporate support and other businesses that do not constitute an operating 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, 2016, Corporate/Other had $4.2 billion of stand-alone holding company long-term debt, of which 28% was subject to variable-interest rates, and $2.7 billion was borrowed by FE under its revolving credit facility.

Segment Financial Information

For the Three Months Ended	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/ Other	Reconciling Adjustments	Consolidated
	(In millions)					
September 30, 2016						
External revenues	$2,702	$ 285	$ 998	$ —	$ (68)	$ 3,917
Internal revenues	—	—	117	—	(117)	—
Total revenues	2,702	285	1,115	—	(185)	3,917
Depreciation	171	45	79	16	—	311
Amortization of regulatory assets, net	98	—	—	—	—	98
Investment income	13	—	23	2	(10)	28
Interest expense	139	43	48	56	—	286
Income taxes (benefits)	167	45	49	(11)	1	251
Net income (loss)	283	78	86	(67)	—	380
Total assets	28,276	8,034	15,165	486	—	51,961
Total goodwill	5,092	526	—	—	—	5,618
Property additions	303	246	110	5	—	664
September 30, 2015						
External revenues	$2,624	$ 248	$ 1,327	$ —	$ (76)	$ 4,123
Internal revenues	—	—	141	—	(141)	—
Total revenues	2,624	248	1,468	—	(217)	4,123
Depreciation	174	41	98	15	—	328
Amortization of regulatory assets, net	110	—	—	—	—	110
Impairment of assets	8	—	—	—	—	8
Investment income (loss)	8	—	(19)	(6)	(11)	(28)
Interest expense	149	40	48	48	—	285
Income taxes (benefits)	137	41	84	(39)	3	226
Net income (loss)	234	70	145	(54)	—	395
Total assets	27,883	6,988	16,229	830	—	51,930
Total goodwill	5,092	526	800	—	—	6,418
Property additions	292	149	83	15	—	539
For the Nine Months Ended						
September 30, 2016						
External revenues	$7,423	$ 824	$ 3,158	$ —	$ (218)	$ 11,187
Internal revenues	—	—	377	—	(377)	—
Total revenues	7,423	824	3,535	—	(595)	11,187
Depreciation	510	132	284	48	—	974
Amortization of regulatory assets, net	218	4	—	—	—	222
Impairment of assets (Note 2)	—	—	1,447	—	—	1,447
Investment income	37	—	56	13	(31)	75
Interest expense	431	128	143	161	—	863
Income taxes (benefits)	349	130	(96)	(51)	2	334
Net income (loss)	594	223	(1,029)	(169)	—	(381)

Property additions	878	755	492	31	—	2,156
September 30, 2015						
External revenues	$7,425	$ 755	$ 3,536	$ —	$ (231)	$ 11,485
Internal revenues	—	—	563	—	(563)	—
Total revenues	7,425	755	4,099	—	(794)	11,485
Depreciation	516	116	293	44	—	969
Amortization of regulatory assets, net	196	5	—	—	—	201
Impairment of assets	8	—	16	—	—	24
Investment income (loss)	33	—	(7)	(9)	(31)	(14)
Interest expense	439	119	144	144	—	846
Income taxes (benefits)	350	135	76	(84)	8	485
Net income (loss)	598	231	129	(154)	—	804
Property additions	884	700	400	41	—	2,025

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 and its subsidiaries are principally involved in the generation, transmission and distribution of electricity. Its 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 controls 3,790 MWs of regulated electric generation capacity located primarily in West Virginia, Virginia and New Jersey. The segment's results reflect the commodity costs of securing electric generation and the deferral and amortization of certain fuel costs.

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). This segment also includes the regulatory asset associated with the abandoned PATH project. The segment's revenues are primarily derived from forward-looking rates at ATSI and TrAIL, as well as fixed rates at certain of FirstEnergy's utilities. Both the forward-looking and fixed rates recover costs and provide a return on transmission capital investment. Under the forward-looking rates, each of ATSI's and TrAIL's revenue requirement is updated annually based on a projected rate base and projected costs, which is subject to annual true-up based on actual costs. Except for the recovery of the PATH abandoned project regulatory asset, the segment's revenues are primarily from transmission services provided to LSEs pursuant to the PJM Tariff. 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. As of September 30, 2016, this business segment controlled 13,162 MWs of electric generating 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, as well as other operating and maintenance costs, including costs incurred by FENOC.

Corporate support and other businesses that do not constitute an operating 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, 2016, Corporate/Other had $4.2 billion of stand-alone holding company long-term debt, of which 28% was subject to variable-interest rates, and $2.7 billion was borrowed by FE under its revolving credit facility.

EXECUTIVE SUMMARY

FirstEnergy believes having a combination of distribution, transmission and generation assets in a regulated or regulated-like construct is the best way to serve customers. The Company's strategy is to be a fully regulated utility, focusing on stable and predictable earnings and cash flow from its regulated business units.

Competitive Energy Services

In order to execute on this strategy, FirstEnergy has begun a strategic review of its competitive operations focused on the sale of gas and hydroelectric units as well as exploring all alternatives for the remaining generation assets at FES and AE Supply. These include, but are not limited to, legislative efforts to convert generation from competitive operations to a regulated or regulated-like construct such as a regulatory restructuring in Ohio, offering generation into any process to address MP's generation shortfall included in its IRP, and/or a solution for nuclear generation that recognize their environmental benefits. Management anticipates that the viability of these alternatives will be determined in the near term with a target to implement these strategic options within the next 12 to 18 months and could result in material asset impairments.

Based on current market forwards, CES, including FES, expects to have more than sufficient cash flow from operations in 2017 and 2018 to fund anticipated capital expenditures with no equity contributions from FirstEnergy. However, in addition to exposure to market price volatility and operational risks, CES, including FES, faces significant financial risks that could impact its anticipated cash flow and liquidity including, but not limited to, the following:

- Requests to post additional collateral or accelerated payments of up to $355 million resulting from current credit ratings at FES, including Moody's downgrade of the Senior Unsecured debt rating for FES to Caa1 as well as S&P's downgrade of the Senior Unsecured debt rating at FES to B, both of which occurred on November 4, 2016.
- Adverse outcomes in the previously disclosed disputes regarding long-term coal transportation contracts.
- The inability to extend or refinance debt maturities at CES, including at FES subsidiaries, in 2017 and 2018 of $130 million and $515 million, respectively.

A significant collateral call or the inability to refinance 2017 debt maturities at FES subsidiaries is expected to be addressed by FES through a combination of cash on hand, additional capital expenditure reductions, asset sales, and/or borrowings under the unregulated money pool. However, adverse outcomes in the coal transportation contracts disputes, the inability to refinance 2018 debt maturities, or lack of viable alternative strategies could cause FES to take one or more of the following actions: (i) restructuring of debt and other financial obligations, (ii) additional borrowings under the unregulated money pool, (iii) further asset sales or plant deactivations, and/or (iv) seek protection under bankruptcy laws. In the event FES seeks such protection, FENOC may similarly seek protection under bankruptcy laws.

Material asset impairments, resulting from the sale or deactivation of generation assets or from a determination by management of its intent to exit competitive generation assets before the end of their estimated useful life resulting from the inability to implement alternative strategies discussed above, adverse judgments or a FES bankruptcy filing could result in an event of default under various agreements related to the indebtedness of FE. Although management expects to successfully resolve any FE defaults through waivers or other actions on acceptable terms and conditions, the failure to do so would have a material and adverse impact on FirstEnergy's financial condition, and FirstEnergy cannot provide any assurance that it will be able to successfully resolve any such defaults on satisfactory terms.

During this period of transition, subject to strategic decisions regarding competitive generation assets, it is anticipated that CES will produce approximately 70 to 75 million MWHs of electricity annually, with up to an additional five million MWHs available from purchased power agreements for wind, solar, and CES' entitlement in OVEC. In 2017 and 2018, CES expects to hedge 75% - 85% of its generation output by targeting approximately 50 to 65 million MWHs in annual contract sales and maintaining up to 25 million MWHs as reserve margin. For the period October 1, 2016 to December 31, 2016, CES' committed sales are 82% hedged against generation supply, including committed purchases, assuming normal weather conditions. As of September 30, 2016, contractual sales obligations for 2017 and 2018 are approximately 48 million MWHs and 28 million MWHs, respectively. Contractual sales obligations for 2016 are approximately 67 million MWHs.

CES will continue to make prudent investments in its nuclear units in order to maintain safe and reliable operations in accordance with nuclear standards, but will continue to focus on costs given current market conditions, specifically surrounding its fossil fleet. Management currently anticipates total capital expenditures of $370 million and $300 million in 2017 and 2018, respectively, which represents a significant reduction from 2016 forecasted capital expenditures of $540 million.

Regulated Transmission

The centerpiece of FirstEnergy's regulated investment strategy continues to be its Energizing the Future transmission plan. The plan includes $4.2 billion in investments from 2014 through 2017 and an additional $800 million to $1.2 billion annually from 2018 to 2021 to modernize FirstEnergy’s transmission system to make it more reliable, robust, secure and resistant to extreme weather events, with improved operational flexibility.

These investments will continue to be focused in our stand-alone transmission companies with formula rates including ATSI, TrAIL and MAIT (which will include the transmission assets from Met-Ed and Penelec), as well as the transmission system at JCP&L as filings were made with FERC on October 28, 2016 to implement and transition to a formula rate for MAIT and JCP&L's transmission investments. FirstEnergy believes existing transmission infrastructure creates improvement investment opportunities of approximately $20 billion beyond those identified through 2021.

Regulated Distribution

The scale and diversity of our regulated utilities has uniquely positioned Regulated Distribution for growth and represents an additional investment opportunity. Although weather-adjusted distribution deliveries through 2019 are forecasted to be flat as compared to 2016, Regulated Distribution’s earnings over the next three years are anticipated to increase as a result of the recent order by the PUCO regarding the Ohio Companies’ ESP IV, which includes approximately $204 million, grossed up for income taxes, in additional annual revenue through rider DMR, current settlement agreements that are pending before the PAPUC regarding the Pennsylvania Companies’ base rate cases, as well as the impact of the settlement-in-principle achieved in the base rate case in New Jersey, which provides for an annual $80 million distribution revenue increase effective on January 1, 2017, subject to finalization, execution and NJBPU approval of a Stipulation of Settlement.

Planned capital expenditures for Regulated Distribution are approximately $1.3 billion, annually for 2017 through 2019.

FINANCIAL OVERVIEW

(In millions, except per share amounts)	For the Three Months Ended September 30				For the Nine Months Ended September 30			
	2016	2015	Change		2016	2015	Change	
REVENUES:	$3,917	$4,123	$(206)	(5)%	$11,187	$11,485	$(298)	(3)%
OPERATING EXPENSES:								
Fuel	450	482	(32)	(7)%	1,269	1,378	(109)	(8)%
Purchased power	979	1,209	(230)	(19)%	2,992	3,311	(319)	(10)%
Other operating expenses	953	842	111	13%	2,835	2,799	36	1%
Provision for depreciation	311	328	(17)	(5)%	974	969	5	1%
Amortization of regulatory assets, net	98	110	(12)	(11)%	222	201	21	10%
General taxes	265	236	29	12%	786	747	39	5%
Impairment of assets	—	8	(8)	(100)%	1,447	24	1,423	NM
Total operating expenses	3,056	3,215	(159)	(5)%	10,525	9,429	1,096	12%
OPERATING INCOME	861	908	(47)	(5)%	662	2,056	(1,394)	(68)%
OTHER INCOME (EXPENSE):								
Investment income (loss)	28	(28)	56	(200)%	75	(14)	89	NM
Interest expense	(286)	(285)	(1)	—%	(863)	(846)	(17)	2%
Capitalized financing costs	28	26	2	8%	79	93	(14)	(15)%
Total other expense	(230)	(287)	57	(20)%	(709)	(767)	58	(8)%
INCOME (LOSS) BEFORE INCOME TAXES	631	621	10	2%	(47)	1,289	(1,336)	(104)%
INCOME TAXES	251	226	25	11%	334	485	(151)	(31)%
NET INCOME (LOSS)	$380	$395	$(15)	(4)%	$(381)	$804	$(1,185)	(147)%
EARNINGS (LOSSES) PER SHARE OF COMMON STOCK:								
Basic	$0.89	$0.94	$(0.05)	(5)%	$(0.90)	$1.91	$(2.81)	(147)%
Diluted	$0.89	$0.93	$(0.04)	(4)%	$(0.90)	$1.90	$(2.80)	(147)%

NM - Not Meaningful

For the Three Months Ended September 30, 2016

FirstEnergy’s net income in the third quarter of 2016 was $380 million, or a basic and diluted earnings of $0.89 per share of common stock, compared with net income of $395 million, or basic earnings of $0.94 per share of common stock ($0.93 diluted) in the third quarter of 2015.

As further discussed below, third quarter 2016 earnings improved over the same period of 2015 at Regulated Distribution and Regulated Transmission but were partially offset by lower earnings at CES and Corp/Other.

During the third quarter of 2016, FirstEnergy’s revenues decreased $206 million as compared to the same period in 2015, primarily resulting from a $353 million decrease at CES, partially offset by a $78 million increase at Regulated Distribution and a $37 million increase at Regulated Transmission.

- The decrease in revenue at CES resulted from a 2.6 million MWH decline in contract sales as the segment continues to align its sales to its generation, as well as lower capacity revenue associated with lower capacity auction prices, partially offset by higher wholesale sales.
- The increase in revenue at Regulated Distribution primarily resulted from a 7% increase in MWH deliveries mainly related to higher weather-related usage as well as higher rates associated with the recovery of deferred program costs, partially offset by lower default service generation sales resulting primarily from lower prices in Ohio and Pennsylvania.
- The increase in revenue at Regulated Transmission resulted from recovery of incremental operating expenses and a higher rate base at ATSI and TrAIL, partially offset by a lower ROE at ATSI.

Operating expenses decreased $159 million in the third quarter of 2016 as compared to the third quarter of 2015, primarily reflecting a decrease at CES of $217 million, partially offset by an increase at Regulated Transmission of $22 million and an increase at Regulated Distribution of $14 million. Changes in certain operating expenses include the following:

- Fuel expense decreased $32 million, primarily resulting from lower generation at CES associated with outages and economic dispatch of fossil units resulting from low wholesale spot market energy prices, as well as lower unit prices on fossil fuel contracts.
- Purchased power decreased $230 million, primarily due to lower capacity expense at CES as a result of lower contract sales and capacity rates, as well as lower default service and wholesale spot market prices.
- Other operating expenses increased $111 million, primarily reflecting an increase of $81 million at Regulated Distribution primarily associated with higher storm restoration expenses, network transmission expenses in Ohio and retirement benefit costs as well as a $31 million increase at CES resulting primarily from a contract termination charge.

Other income (expense) increased $57 million, primarily from lower OTTI on NDT investments. FirstEnergy’s effective tax rate was 39.8% for the three months ended September 30, 2016 compared to 36.4% for the same period in 2015.

For the Nine Months Ended September 30, 2016

For the nine months ended September 30, 2016, FirstEnergy's net loss was $381 million, or a basic and diluted loss of $(0.90) per share of common stock, compared to net income of $804 million, or basic earnings of $1.91 per share of common stock ($1.90 diluted) for the nine months ended September 30, 2015.

FirstEnergy's 2016 year-to-date earnings decreased $1,185 million as compared to the same period of 2015 primarily reflecting asset impairment and plant exit costs recognized in the second quarter of 2016 consisting of:

- Non-cash impairment charge of $800 million (pre-tax) associated with goodwill at CES,
- Non-cash impairment charges of $647 million (pre-tax) associated with the announced plan to exit operations by 2020 of Units 1-4 of the W.H. Sammis generation station (720 MW) and the Bay Shore Unit 1 generating station (136 MW),
- Coal contract settlement and termination costs of $58 million (pre-tax), and
- Valuation allowances against state and local NOL carryforwards of $159 million.

During the first nine months of 2016, FirstEnergy’s revenues decreased $298 million as compared to the same period in 2015, resulting from a $564 million decrease at CES, partially offset by an increase of $69 million at Regulated Transmission.

- The decrease in revenue at CES resulted from a 13 million MWH decline in contract sales as the segment continues to align its sales to its generation. The decline in contract sales volume was partially offset by higher wholesale sales, increased capacity revenue associated with capacity auction prices, and higher net gains on financially settled contracts.
- The increase in revenue at Regulated Transmission primarily reflected recovery of incremental operating expenses and higher rate base at ATSI and TrAIL, partially offset by adjustments associated with ATSI and TrAIL's annual rate filing for costs previously recovered as well as a lower ROE at ATSI under its FERC-approved comprehensive settlement related to the implementation of a forward-looking rate.

Operating expenses increased $1,096 million during the first nine months of 2016 as compared to 2015, mainly reflecting an increase at CES of $830 million, resulting primarily from the asset impairment and plant exit costs described above, and an increase at Regulated Transmission of $62 million. Changes in certain operating expenses include the following:

- Fuel expense decreased $109 million mainly resulting from lower generation at CES associated with outages and economic dispatch of fossil units reflecting low wholesale spot market energy prices, as well as lower unit prices on fossil fuel contracts.
- Purchased power decreased $319 million mainly due to lower volumes at CES and Regulated Distribution and lower capacity expense at CES.

Other income (expense) increased $58 million, primarily from lower OTTI on NDT investments. Changes in FirstEnergy’s effective tax rate for the nine months ended September 30, 2016 compared to the same period in 2015, primarily related to the second quarter of 2016 impairment of $800 million of goodwill, of which $433 million is non-deductible for tax purposes. Additionally, $159 million of valuation allowances were recorded against state and local NOL carryforwards in the second quarter of 2016 that management believes, more likely than not, will not be realized based primarily on projected taxable income reflecting updates to FirstEnergy's annual long-term fundamental pricing model for energy and capacity, as well as certain statutory limitations on the utilization of state and local NOL carryforwards.

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 14, Segment Information, of the Combined Notes to Consolidated Financial Statements. Certain prior year amounts have been reclassified to conform to the current year presentation.

Summary of Results of Operations — Third Quarter 2016 Compared with Third Quarter 2015

Financial results for FirstEnergy's business segments in the third quarter of 2016 and 2015 were as follows:

Third Quarter 2016 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$2,649	$ 285	$ 959	$ (46)	$ 3,847
Other	53	—	39	(22)	70
Internal	—	—	117	(117)	—
Total Revenues	2,702	285	1,115	(185)	3,917
Operating Expenses:					
Fuel	156	—	294	—	450
Purchased power	902	—	194	(117)	979
Other operating expenses	615	46	367	(75)	953
Provision for depreciation	171	45	79	16	311
Amortization of regulatory assets, net	98	—	—	—	98
General taxes	190	37	30	8	265
Impairment of assets	—	—	—	—	—
Total Operating Expenses	2,132	128	964	(168)	3,056
Operating Income	570	157	151	(17)	861
Other Income (Expense):					
Investment income	13	—	23	(8)	28
Interest expense	(139)	(43)	(48)	(56)	(286)
Capitalized financing costs	6	9	9	4	28
Total Other Expense	(120)	(34)	(16)	(60)	(230)
Income Before Income Taxes	450	123	135	(77)	631
Income taxes	167	45	49	(10)	251
Net Income	$283	$ 78	$ 86	$ (67)	$ 380

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	534	42	336	(70)	842
Provision for depreciation	174	41	98	15	328
Amortization of regulatory assets, net	110	—	—	—	110
General taxes	172	23	35	6	236
Impairment of assets	8	—	—	—	8
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	—	(19)	(17)	(28)
Interest expense	(149)	(40)	(48)	(48)	(285)
Capitalized financing costs	6	9	9	2	26
Total Other Expense	(135)	(31)	(58)	(63)	(287)
Income Before Income Taxes	371	111	229	(90)	621
Income taxes	137	41	84	(36)	226
Net Income	$234	$ 70	$ 145	$ (54)	$ 395

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Changes Between Third Quarter 2016 and Third Quarter 2015 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$78	$ 37	$ (317)	$ (5)	$ (207)
Other	—	—	(12)	13	1
Internal	—	—	(24)	24	—
Total Revenues	78	37	(353)	32	(206)
Operating Expenses:					
Fuel	16	—	(48)	—	(32)
Purchased power	(78)	—	(176)	24	(230)
Other operating expenses	81	4	31	(5)	111
Provision for depreciation	(3)	4	(19)	1	(17)
Amortization of regulatory assets, net	(12)	—	—	—	(12)
General taxes	18	14	(5)	2	29
Impairment of assets	(8)	—	—	—	(8)
Total Operating Expenses	14	22	(217)	22	(159)
Operating Income	64	15	(136)	10	(47)
Other Income (Expense):					
Investment income	5	—	42	9	56
Interest expense	10	(3)	—	(8)	(1)
Capitalized financing costs	—	—	—	2	2
Total Other Expense	15	(3)	42	3	57
Income Before Income Taxes	79	12	(94)	13	10
Income taxes	30	4	(35)	26	25
Net Income	$49	$ 8	$ (59)	$ (13)	$ (15)

Regulated Distribution — Third Quarter 2016 Compared with Third Quarter 2015

Regulated Distribution's net income increased $49 million in the third quarter of 2016 as compared to the same period of 2015, reflecting higher revenues associated with cooling degree days that were 28% above 2015, partially offset by higher operating and maintenance costs and increased retirement benefit costs.

Revenues —

The $78 million increase in total revenues resulted from the following sources:

Revenues by Type of Service	For the Three Months Ended September 30 2016	2015	Increase (Decrease)
	(In millions)		
Distribution services	$1,390	$1,245	$ 145
Generation sales:			
Retail	1,117	1,182	(65)
Wholesale	142	144	(2)
Total generation sales	1,259	1,326	(67)
Other	53	53	—
Total Revenues	$2,702	$2,624	$ 78

Distribution services revenues increased $145 million primarily resulting from higher MWH deliveries, described below, and a rate increase associated with the Ohio Companies' rider DCR. Additionally, distribution service revenues increased related to higher rates associated with the recovery of deferred costs, including Ohio Companies' NMB transmission rider revenues, and a surcharge increase in West Virginia associated with the recovery of vegetation management deferred program costs, effective January 1, 2016. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	For the Three Months Ended September 30 2016	2015	Increase (Decrease)
	(In thousands)		
Residential	16,138	14,305	12.8 %
Commercial	12,005	11,463	4.7 %
Industrial	13,023	12,721	2.4 %
Other	144	146	(1.4)%
Total Electric Distribution MWH Deliveries	41,310	38,635	6.9 %

Higher distribution deliveries to residential and commercial customers primarily reflect increased weather-related usage resulting from cooling degree days that were 28% above 2015, and 46% above normal. Deliveries to industrial customers increased related to higher shale, coal and steel customer usage.

The following table summarizes the price and volume factors contributing to the $67 million decrease in generation revenues for the third quarter of 2016 compared to the same period of 2015:

Source of Change in Generation Revenues	Increase (Decrease)
	(In millions)
Retail:	
Effect of increase in sales volumes	$ 16
Change in prices	(81)
	(65)
Wholesale:	
Effect of increase in sales volumes	10
Change in prices	(1)
Capacity Revenue	(11)
	(2)
Decrease in Generation Revenues	$ (67)

The decrease in retail generation sales primarily resulted from lower default service auction prices in Ohio and Pennsylvania. The increase in retail generation volumes was primarily due to weather-related volume, as described above, partially offset by increased customer shopping in Ohio and New Jersey. Total generation provided by alternative suppliers as a percentage of total MWH deliveries increased to 85% from 81% for the Ohio Companies and to 48% from 47% for JCP&L.

The decrease in wholesale generation revenues of $2 million in the third quarter of 2016, as compared to the same period in 2015, reflects lower capacity revenues partially offset by higher wholesale sales. The difference between current wholesale generation revenues and certain energy costs incurred are deferred for future recovery or refund, with no material impact to earnings.

Operating Expenses —

Total operating expenses increased $14 million primarily due to the following:

- Fuel expense increased $16 million in the third quarter of 2016, as compared to the same period in 2015, primarily related to higher generation.

- Purchased power costs were $78 million lower in the third quarter of 2016, as compared to the same period in 2015, primarily due to decreased unit cost reflecting lower default service auction prices in Ohio and Pennsylvania.

Source of Change in Purchased Power	Increase(Decrease)
	(In millions)
Purchases from non-affiliates:	
Change due to decreased unit costs	$ (85)
Change due to increased volumes	10
	(75)
Purchases from affiliates:	
Change due to decreased unit costs	(14)
Change due to increased volumes	(9)
	(23)

Capacity Expense		(7)
Amortization of deferred costs		27
Decrease in Purchased Power Costs	$	(78)

- Other operating expenses increased $81 million primarily due to:
- Higher operating and maintenance expense of $37 million including higher storm restoration costs of $32 million, which are deferred for future recovery, resulting in no material impact on current period earnings.
- Higher transmission expenses of $24 million primarily due to an increase in network transmission expenses at the Ohio Companies. The difference between current revenues and transmission costs incurred are deferred for future recovery or refund, resulting in no material impact on current period earnings.
- Higher retirement benefit costs of $12 million.

- Net amortization of regulatory assets decreased $12 million primarily due to higher deferral of storm restoration costs, partially offset by increased recovery of vegetation management program costs in West Virginia and increased recovery of network transmission expenses in Ohio.

- General taxes increased $18 million primarily due to higher property taxes and higher revenue-related taxes in Ohio.

Other Expense —

Other expenses decreased $15 million primarily due to lower interest expense associated with various debt redemptions at JCP&L, OE, and MP and lower OTTI on NDT investments.

Income Taxes —

Regulated Distribution’s effective tax rate was 37.1% and 36.9% for the quarter ended September 30, 2016 and 2015, respectively.

Regulated Transmission — Third Quarter 2016 Compared with Third Quarter 2015

Net income increased $8 million in the third quarter of 2016 compared to the same period of 2015 reflecting higher transmission revenues, as described below.

Revenues —

Total revenues increased $37 million principally due to recovery of incremental operating expenses and a higher rate base at ATSI and TrAIL, partially offset by a lower ROE at ATSI under its FERC-approved comprehensive settlement related to the implementation of a forward-looking rate.

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

	For the Three Months Ended September 30		
Revenues by Transmission Asset Owner	2016	2015	Increase
	(In millions)		
ATSI	$139	$110	$ 29
TrAIL	67	60	7
PATH	3	3	—
Utilities	76	75	1
Total Revenues	$285	$248	$ 37

Operating Expenses —

Total operating expenses increased $22 million principally due to higher property taxes, depreciation, and other operating expenses at ATSI, which are recovered through ATSI's formula rate.

Other Expense —

Total other expense increased $3 million in the third quarter of 2016 as compared to the same period of 2015 primarily due to increased interest expense resulting from debt issuances of $150 million at ATSI in the fourth quarter of 2015, the proceeds of which, in part, paid off short-term borrowings.

Income Taxes —

Regulated Transmission’s effective tax rate was 36.6% and 36.9% for the quarter ended September 30, 2016 and 2015, respectively.

CES — Third Quarter 2016 Compared with Third Quarter 2015

Operating results decreased $59 million in the third quarter of 2016, compared to the same period of 2015, primarily resulting from lower contract sales volumes, lower capacity revenues from lower capacity auction prices, lower mark-to-market gains on commodity contract positions, and a termination charge associated with a FES customer contract, partially offset by higher wholesale sales volumes and lower fuel and purchased power.

Revenues —

Total revenues decreased $353 million in the third quarter of 2016, compared to the same period of 2015, primarily due to lower capacity revenues from lower capacity auction prices, lower contract sales volumes and lower unit prices. Revenues were also impacted by higher wholesale sales volumes, partially offset by lower net gains on financially settled contracts, as further described below.

The change in total revenues resulted from the following sources:

Revenues by Type of Service	For the Three Months Ended September 30 2016	2015	Increase (Decrease)
	(In millions)		
Contract Sales:			
Direct	$207	$296	$ (89)
Governmental Aggregation	235	296	(61)
Mass Market	47	62	(15)
POLR	165	141	24
Structured Sales	94	170	(76)
Total Contract Sales	748	965	(217)
Wholesale	311	429	(118)
Transmission	17	23	(6)
Other	39	51	(12)
Total Revenues	$1,115	$1,468	$ (353)

MWH Sales by Channel	For the Three Months Ended September 30 2016	2015	Increase (Decrease)
	(In thousands)		
Contract Sales:			
Direct	3,913	5,541	(29.4)%
Governmental Aggregation	4,238	4,226	0.3 %
Mass Market	673	906	(25.7)%
POLR	2,893	2,168	33.4 %
Structured Sales	2,437	3,893	(37.4)%
Total Contract Sales	14,154	16,734	(15.4)%
Wholesale	4,447	3,156	40.9 %
Total MWH Sales	18,601	19,890	(6.5)%

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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	$(87)	$(2)	$ —	$ —	$(89)
Governmental Aggregation	1	(62)	—	—	(61)
Mass Market	(16)	1	—	—	(15)
POLR	47	(23)	—	—	24
Structured Sales	(64)	(12)	—	—	(76)
Wholesale	38	3	(9)	(150)	(118)

Lower sales volumes in Direct and Mass Market channels primarily reflects the continuation of CES' strategy to more effectively hedge its generation. The Direct, Governmental Aggregation and Mass Market customer base was 1.4 million as of September 30, 2016, compared to 1.7 million as of September 30, 2015. Although unit pricing was lower year-over-year in the Governmental Aggregation channel, the decrease was primarily attributable to lower capacity expense as discussed below, which is a component of the retail price.

The increase in POLR sales of $24 million was due to higher volumes, partially offset by lower rates associated with POLR auctions. Structured Sales decreased $76 million primarily due to the impact of lower market prices and lower structured transaction volumes.

Wholesale revenues decreased $118 million, primarily due to a decrease in capacity revenue from capacity auctions and lower gains on financially settled contracts, partially offset by an increase in short-term (net hourly position) transactions at higher realized prices. Although wholesale short-term transactions and prices increased year-over-year, low average spot market energy prices reduced the economic dispatch of fossil generating units, limiting additional wholesale sales.

Operating Expenses —

Total operating expenses decreased $217 million in the third quarter of 2016 due to the following:

- Fuel costs decreased $48 million, primarily due to lower generation associated with outages and economic dispatch of fossil units resulting from low wholesale spot market energy prices, as described above, as well as lower unit prices on fossil fuel contracts.
- Purchased power costs decreased $176 million due to lower capacity expense ($137 million), lower prices ($27 million) and lower volumes ($12 million). Lower volumes primarily resulted from lower contract sales as discussed above, partially offset by economic purchases, resulting from the low wholesale spot market price environment. The decrease in capacity expense, which is a component of CES' retail price, was primarily the result of lower contract sales and lower capacity rates associated with CES' retail sales obligation. Lower prices reflect lower realized prices on economic purchases.

- Depreciation expense decreased $19 million, primarily as a result of an out-of-period adjustment to reduce the depreciation of a hydroelectric generating station.

- Transmission expenses decreased $12 million due to lower congestion and market-based ancillary costs, primarily resulting from lower contract sales.

- Other operating expenses increased $43 million, primarily due to lower mark-to-market gains on commodity contract positions of $41 million, higher benefit costs and a $32 million charge associated with the termination of a FES customer contract, partially offset by lower lease expense as a result of the expiration of a nuclear sale-leaseback agreement and lower retail-related costs.

Other Expense —

Total other expense decreased $42 million in the third quarter of 2016, as compared to the same period of 2015, primarily due to lower OTTI on NDT investments.

Income Taxes —

CES' effective tax rate was 36.3% and 36.7% for the third quarter of 2016 and 2015, respectively.

Corporate / Other — Third Quarter 2016 Compared with Third Quarter 2015

Financial results from the Corporate/Other operating segment and reconciling items, including interest expense on holding company debt, corporate support services revenues and expenses and income taxes, resulted in a $13 million decrease in earnings in the third quarter of 2016, compared to the same period of 2015, primarily associated with a higher consolidated effective tax rate.

Summary of Results of Operations — First Nine Months of 2016 Compared with First Nine Months of 2015

Financial results for FirstEnergy's business segments in the first nine months of 2016 and 2015 were as follows:

First Nine Months 2016 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$7,238	$ 824	$ 3,023	$ (135)	$ 10,950
Other	185	—	135	(83)	237
Internal	—	—	377	(377)	—
Total Revenues	7,423	824	3,535	(595)	11,187
Operating Expenses:					
Fuel	436	—	833	—	1,269
Purchased power	2,549	—	820	(377)	2,992
Other operating expenses	1,843	118	1,120	(246)	2,835
Provision for depreciation	510	132	284	48	974
Amortization of regulatory assets, net	218	4	—	—	222
General taxes	545	114	98	29	786
Impairment of assets	—	—	1,447	—	1,447
Total Operating Expenses	6,101	368	4,602	(546)	10,525
Operating Income (Loss)	1,322	456	(1,067)	(49)	662
Other Income (Expense):					
Investment income	37	—	56	(18)	75
Interest expense	(431)	(128)	(143)	(161)	(863)
Capitalized financing costs	15	25	29	10	79
Total Other Expense	(379)	(103)	(58)	(169)	(709)
Income (Loss) Before Income Taxes (Benefits)	943	353	(1,125)	(218)	(47)
Income taxes (benefits)	349	130	(96)	(49)	334
Net Income (Loss)	$594	$ 223	$ (1,029)	$ (169)	$ (381)

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	1,669	112	1,266	(248)	2,799
Provision for depreciation	516	116	293	44	969
Amortization of regulatory assets, net	196	5	—	—	201
General taxes	536	73	112	26	747
Impairment of assets	8	—	16	—	24
Total Operating Expenses	6,092	306	3,772	(741)	9,429
Operating Income	1,333	449	327	(53)	2,056
Other Income (Expense):					
Investment income (loss)	33	—	(7)	(40)	(14)
Interest expense	(439)	(119)	(144)	(144)	(846)
Capitalized financing costs	21	36	29	7	93
Total Other Expense	(385)	(83)	(122)	(177)	(767)
Income Before Income Taxes	948	366	205	(230)	1,289
Income taxes	350	135	76	(76)	485
Net Income	$598	$ 231	$ 129	$ (154)	$ 804

Changes Between First Nine Months 2016 and 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	$(39)	$ 69	$ (358)	$ (6)	$ (334)
Other	37	—	(20)	19	36
Internal	—	—	(186)	186	—
Total Revenues	(2)	69	(564)	199	(298)
Operating Expenses:					
Fuel	30	—	(139)	—	(109)
Purchased power	(212)	—	(293)	186	(319)
Other operating expenses	174	6	(146)	2	36
Provision for depreciation	(6)	16	(9)	4	5
Amortization of regulatory assets, net	22	(1)	—	—	21
General taxes	9	41	(14)	3	39
Impairment of assets	(8)	—	1,431	—	1,423
Total Operating Expenses	9	62	830	195	1,096
Operating Income (Loss)	(11)	7	(1,394)	4	(1,394)
Other Income (Expense):					
Investment income	4	—	63	22	89
Interest expense	8	(9)	1	(17)	(17)
Capitalized financing costs	(6)	(11)	—	3	(14)
Total Other Expense	6	(20)	64	8	58
Income (Loss) Before Income Taxes (Benefits)	(5)	(13)	(1,330)	12	(1,336)
Income taxes (benefits)	(1)	(5)	(172)	27	(151)
Net Income (Loss)	$(4)	$ (8)	$ (1,158)	$ (15)	$ (1,185)

Regulated Distribution — First Nine Months of 2016 Compared with First Nine Months of 2015

Regulated Distribution's net income decreased $4 million in the first nine months of 2016 as compared to the same period of 2015, reflecting increasing retirement benefit costs and lower distribution deliveries, partially offset by the impact of net rate increases implemented in 2015 as a result of approved rate cases at certain operating companies, as further described below. Additionally, the Ohio Companies recognized $51 million in regulatory charges in the second quarter of 2016 resulting from the PUCO's March 31 Opinion and Order adopting and approving, with modifications, the Ohio Companies' ESP IV.

Revenues —

The $2 million decrease in total revenues resulted from the following sources:

Revenues by Type of Service	For the Nine Months Ended September 30 2016	2015	Increase (Decrease)
	(In millions)		
Distribution services	$3,681	$3,502	$ 179
Generation sales:			
Retail	3,173	3,331	(158)
Wholesale	384	444	(60)
Total generation sales	3,557	3,775	(218)
Other	185	148	37
Total Revenues	$7,423	$7,425	$ (2)

Distribution services revenues increased $179 million primarily resulting from approved base distribution rate increases in Pennsylvania, effective May 3, 2015, and 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. Partially offsetting this net rate increase was a decline in MWH deliveries, primarily resulting from lower average customer usage, as described below. Additionally, distribution revenues were impacted by higher rates associated with the recovery of deferred costs. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	For the Nine Months Ended September 30 2016	2015	(Decrease)
	(In thousands)		
Residential	42,130	42,706	(1.3)%
Commercial	32,913	33,006	(0.3)%
Industrial	37,746	38,149	(1.1)%
Other	437	438	(0.2)%
Total Electric Distribution MWH Deliveries	113,226	114,299	(0.9)%

Lower distribution deliveries to residential and commercial customers reflect declining average customer usage associated with more energy efficient products and services. Additionally, weather-related distribution deliveries to residential and commercial customers were flat resulting from heating degree days that were 17% below 2015, and 9%

below normal and cooling degree days that were 16% above 2015, and 36% above normal. Year-to-date deliveries to industrial customers have declined as the increase from shale 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 $218 million decrease in generation revenues for the first nine months of 2016 compared to the same period of 2015:

Source of Change in Generation Revenues	Increase (Decrease)
	(In millions)
Retail:	
Effect of decrease in sales volumes	$ (190)
Change in prices	32
	(158)
Wholesale:	
Effect of increase in sales volumes	43
Change in prices	(101)
Capacity Revenue	(2)
	(60)
Decrease in Generation Revenues	$ (218)

The decrease in retail generation sales volumes was primarily due to increased customer shopping in Ohio, Pennsylvania, and New Jersey and industrial usage in West Virginia, as described above. Total generation provided by alternative suppliers as a percentage of total MWH deliveries increased to 82% from 80% for the Ohio Companies, to 67% from 65% for the Pennsylvania Companies and to 51% from 49% for JCP&L. The increase in retail generation prices primarily resulted an ENEC rate increase in West Virginia, effective January 1, 2016, partially offset by lower default service auction prices in Ohio and Pennsylvania.

Wholesale generation revenues decreased $60 million in the first nine months of 2016, as compared to the same period of 2015, primarily due to lower spot market energy prices, partially offset by higher wholesale sales. The difference between current wholesale generation revenues and certain energy costs incurred are deferred for future recovery or refund, with no material impact to earnings.

Other revenues increased $37 million primarily related to a $29 million gain on the sale of oil and gas rights at WP.

Operating Expenses —

Total operating expenses increased $9 million primarily due to the following:

- Fuel expense increased $30 million in the first nine months of 2016, as compared to the same period of 2015, primarily related to higher generation.

- Purchased power costs decreased $212 million during the first nine months of 2016, as compared to the same period of 2015 primarily due to decreased volumes resulting from increased customer shopping, as described above, as well as lower unit costs reflecting lower default service auction prices in Ohio and Pennsylvania

Source of Change in Purchased Power	Increase (Decrease)
	(In millions)
Purchases from non-affiliates:	
Change due to decreased unit costs	$ (83)
Change due to volumes	16
	(67)

Purchases from affiliates:	
Change due to increased unit costs	6
Change due to volumes	(191)
	(185)
Capacity Expense	2
Amortization of deferred costs	38
Decrease in Purchased Power Costs	$ (212)

- Other operating expenses increased $174 million primarily due to:
- An increase of $51 million resulting from the recognition of economic development and energy efficiency obligations in accordance with the PUCO's March 31 Opinion and Order adopting and approving, with modifications, the Ohio Companies' ESP IV.
- Higher operating and maintenance expense of $42 million, including increased storm restoration costs of $39 million, which are deferred for future recovery, resulting in no material impact on current period earnings.
- Higher retirement benefit costs of $37 million.
- Higher transmission expenses of $36 million primarily related to an increase in network transmission expenses at the Ohio Companies, partially offset by lower congestion expenses at MP. The difference between current revenues and costs incurred are deferred for future recovery or refund, resulting in no material impact on current period earnings.

- Net amortization of regulatory assets increased $22 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 ($35 million),
- Recovery of West Virginia vegetation management program costs ($34 million), partially offset by
- Higher deferral of storm restoration costs ($39 million), and
- Higher deferral of Ohio network transmission expenses ($10 million).

Income Taxes —

Regulated Distribution’s effective tax rate was 37.0% for the first nine months of 2016 and 2015.

Regulated Transmission — First Nine Months of 2016 Compared with First Nine Months of 2015

Net income decreased $8 million in the first nine months of 2016, compared to the same period of 2015, primarily resulting from adjustments associated with ATSI and TrAIL's annual rate filing for costs previously recovered, a lower return on equity at ATSI, and lower capitalized financing costs, partially offset by higher rate base.

Revenues —

Total revenues increased $69 million principally due to recovery of incremental operating expenses and a higher rate base at ATSI and TrAIL, partially offset by adjustments associated with ATSI's and TrAIL's annual rate filing for costs previously recovered as well as a lower ROE at ATSI under its FERC-approved comprehensive settlement related to the implementation of a forward-looking rate.

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

Revenues by Transmission Asset Owner	For the Nine Months Ended September 30 2016	2015	Increase (Decrease)
	(In millions)		
ATSI	$401	$333	$ 68
TrAIL	187	186	1
PATH	9	10	(1)
Utilities	227	226	1
Total Revenues	$824	$755	$ 69

Operating Expenses —

Total operating expenses increased $62 million principally due to higher property taxes and depreciation expense at ATSI, which are recovered through ATSI's formula rate.

Other Expense —

Other expense increased $20 million in the first nine months of 2016 compared to the same period of 2015 primarily due to lower capitalized financing costs resulting from lower construction work in progress balances at ATSI as well as increased interest expense resulting from debt issuances of $150 million at ATSI in the fourth quarter of 2015, the proceeds of which, in part, paid off short-term borrowings.

Income Taxes —

Regulated Transmission's effective tax rate was 36.8% and 36.9% for the first nine months of 2016 and 2015, respectively.

CES — First Nine Months of 2016 Compared with First Nine Months of 2015

Operating results decreased $1,158 million in the first nine months of 2016, compared to the same period of 2015, primarily resulting from charges associated with impairments of goodwill, Units 1-4 of the W. H. Sammis generating station and the Bay Shore Unit 1 generating station, as discussed above, termination and settlement costs on coal contracts and lower mark-to-market gains on commodity contract positions. In addition to these items, operating results were impacted by higher capacity revenues, lower fuel costs and lower purchased power, partially offset by lower sales volumes and a termination charge associated with a FES customer contract.

Revenues —

Total revenues decreased $564 million in the first nine months of 2016, compared to the same period of 2015, primarily due to lower sales volumes, partially offset by higher capacity revenues and higher net gains on financially settled contracts, as further described below.

The decrease in total revenues resulted from the following sources:

Revenues by Type of Service	For the Nine Months Ended September 30 2016	2015	Increase (Decrease)
	(In millions)		
Contract Sales:			
Direct	$610	$1,014	$ (404)
Governmental Aggregation	666	802	(136)
Mass Market	133	222	(89)
POLR	447	585	(138)
Structured Sales	371	429	(58)
Total Contract Sales	2,227	3,052	(825)
Wholesale	1,117	776	341
Transmission	56	116	(60)
Other	135	155	(20)
Total Revenues	$3,535	$4,099	$ (564)

MWH Sales by Channel	For the Nine Months Ended September 30 2016	2015	Increase (Decrease)
	(In thousands)		
Contract Sales:			
Direct	11,391	18,860	(39.6)%
Governmental Aggregation	10,798	12,278	(12.1)%
Mass Market	1,912	3,246	(41.1)%
POLR	7,526	9,910	(24.1)%
Structured Sales	9,175	9,790	(6.3)%

Total Contract Sales	40,802	54,084	(24.6)%
Wholesale	9,938	4,023	147.0 %
Total MWH Sales	50,740	58,107	(12.7)%

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	$ (401)	$ (3)	$ —	$ —	$ (404)
Governmental Aggregation	(97)	(39)	—	—	(136)
Mass Market	(91)	2	—	—	(89)
POLR	(140)	2	—	—	(138)
Structured Sales	(27)	(31)	—	—	(58)
Wholesale	175	(16)	113	69	341

Lower sales volumes in Direct, Governmental Aggregation and Mass Market channels primarily reflects the continuation of CES' strategy to more effectively hedge its generation. The Direct, Governmental Aggregation and Mass Market customer base was 1.4 million as of September 30, 2016, compared to 1.7 million as of September 30, 2015. Although unit pricing was lower year-over-year in the Governmental Aggregation channel, the decrease was primarily attributable to lower capacity expense as discussed below, which is a component of the retail price.

The decrease in POLR sales of $138 million was primarily due to lower volumes. Structured Sales decreased $58 million, primarily due to the impact of lower market prices and lower structured transaction volumes.

Wholesale revenues increased $341 million, primarily due to an increase in capacity revenue from capacity auctions, an increase in short-term (net hourly position) transactions and higher net gains on financially settled contracts, partially offset by lower spot market energy prices. 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.

Transmission revenue decreased $60 million, primarily due to lower congestion revenue associated with less volatile market conditions.

Other revenue decreased $20 million, primarily due to the absence of a pre-tax gain on the sale of property to a regulated affiliate in the second quarter of 2015 and lower lease revenues from the expiration of a nuclear sale-leaseback agreement.

Operating Expenses —

Total operating expenses increased $830 million in the first nine months of 2016, compared to the same period of 2015, due to the following:

- Fuel costs decreased $139 million, primarily due to lower generation associated with outages and economic dispatch of fossil units resulting from low wholesale spot market energy prices, as described above, as well as lower unit prices on fossil fuel contracts. Additionally, fuel costs were impacted by higher settlement and termination costs on coal contracts.
- Purchased power costs decreased $293 million, primarily due to lower volumes ($206 million) and lower capacity expenses ($112 million), partially offset by higher losses on financial settled contracts from lower wholesale spot market prices ($25 million). Lower volumes primarily resulted from lower contract sales as discussed above, partially

offset by economic purchases, resulting from the low wholesale spot market price environment. The decrease in capacity expense, which is a component of CES' retail price, was primarily the result of lower contract sales and lower capacity rates associated with CES' retail sales obligations.

- Fossil operating costs increased $18 million, primarily due to increased outage costs and higher employee benefit costs.

- Nuclear operating costs decreased $31 million, primarily as a result of lower refueling outage costs, partially offset by higher employee benefit costs. There was one refueling outage during the first nine months of 2016 as compared to two refueling outages during the same period of 2015.

- Retirement benefit costs increased $24 million.

- Transmission expenses decreased $162 million, primarily due to lower congestion and market-based ancillary costs associated with less volatile market conditions as compared to the first nine months of 2015, as well as lower load requirements.

- Other operating expenses increased $5 million, primarily due to lower mark-to-market gains on commodity contract positions of $54 million and a $32 million charge associated with the termination of a FES customer contract, partially offset by lower lease expense as a result of the expiration of a nuclear sale-leaseback agreement and lower retail-related costs.
- Depreciation expense decreased $9 million, primarily as a result of an out-of-period adjustment to reduce the depreciation of a hydroelectric generating station, partially offset by a higher asset base.
- General taxes decreased $14 million, primarily due to lower gross receipts taxes associated with lower retail sales volumes.
- Impairment of assets increased $1,431 million primarily due to an $800 million impairment of goodwill and a decision to exit operations of Units 1-4 of the W. H. Sammis generating station by May 31, 2020 and the Bay Shore Unit 1 generating station by October 1, 2020.

Other Expense —

Total other expense decreased $64 million in the first nine months of 2016, compared to the same period of 2015, primarily due to lower OTTI on NDT investments.

Income Taxes (Benefits) —

CES' effective tax rate was 8.5% and 37.1% for the first nine months of 2016 and 2015, respectively. The decrease in the effective tax rate is primarily due to valuation allowances of $159 million recorded against state and local NOL carryforwards that management believes, more likely than not, will not be realized as discussed above as well as the impairment of goodwill, of which, $433 million is non-deductible for tax purposes.

Corporate / Other — First Nine Months of 2016 Compared with First Nine Months of 2015

Financial results from the Corporate/Other operating segment and reconciling items resulted in a $15 million decrease in net income in the first nine months of 2016 compared to the same period of 2015. Increased taxes at the Corporate/Other operating segment resulted from an increased consolidated tax rate and the impact of estimated annual permanent items on lower pre-tax income for the period.

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, 2016 and December 31, 2015, and the changes during the nine months ended September 30, 2016:

Regulatory Assets (Liabilities) by Source	September 30, 2016	December 31, 2015	Increase (Decrease)
	(In millions)		
Regulatory transition costs	$123	$ 185	$ (62)
Customer receivables for future income taxes	427	355	72
Nuclear decommissioning and spent fuel disposal costs	(316)	(272)	(44)
Asset removal costs	(470)	(372)	(98)
Deferred transmission costs	123	115	8

Deferred generation costs	247	243	4
Deferred distribution costs	305	335	(30)
Contract valuations	166	186	(20)
Storm-related costs	375	403	(28)
Other	108	170	(62)
Net Regulatory Assets included on the Consolidated Balance Sheets	$1,088	$ 1,348	$ (260)

Regulatory assets that do not earn a current return totaled approximately $148 million as of September 30, 2016 and December 31, 2015, respectively, primarily related to storm damage costs.

As of September 30, 2016 and December 31, 2015, FirstEnergy had approximately $142 million and $116 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 2016 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, including cash requirements to fund Regulated Transmission's capital program, may be met through a combination of an additional $500 million of equity in each year 2017 through 2019, subject to certain market conditions, and new long-term debt. FirstEnergy also expects to issue long-term debt at certain Utilities to, among other things, refinance short-term and maturing debt, subject to market and other conditions. Furthermore, FES subsidiaries have debt maturities in 2017 and 2018 of $130 million and $515 million, respectively, which will need to be refinanced. The inability to refinance the 2017 debt maturities at FES could be addressed through a combination of cash on hand, additional capital expenditure reductions, asset sales, and/or borrowings under the unregulated money pool. The inability to refinance 2018 debt maturities at FES could cause FES to take one or more of the following actions: (i) restructuring of debt and other financial obligations, (ii) additional borrowings under the unregulated money pool, (iii) further asset sales or plant deactivations, and/or (iv) seek protection under bankruptcy laws. In the event FES seeks such protection, FENOC may similarly be forced to seek protection under bankruptcy laws.

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. However, if material impairments are recognized as FirstEnergy executes on its strategy to transition to a fully regulated utility resulting in a consolidated debt to total capitalization ratio, as defined under each of the revolving credit facilities as discussed below, in excess of 65%, then FE would be in default under various credit agreements related to the indebtedness of FE. Furthermore, adverse judgments or a FES bankruptcy filing could also result in an event of default. Although management expects to successfully resolve any FE defaults through waivers or other actions on acceptable terms and conditions, the failure to do so would have a material and adverse impact on FirstEnergy's financial condition, and FirstEnergy cannot provide any assurance that it will be able to successfully resolve any such defaults on satisfactory terms.

Through October 2016, FirstEnergy satisfied its minimum required funding obligations to its qualified pension plan for the year with contributions of $382 million ($85 million in October 2016), including $138 million at FES. Depending on, among other things, market conditions, FirstEnergy expects to make additional contributions to its qualified pension plan in 2016 of up to $500 million of equity to address its funding obligations for future years.

Planned capital expenditures for 2016 through 2018 by reportable segment are included below:

Reportable Segment	Capital Expenditures Forecast 2016	Capital Expenditures Forecast 2017	Capital Expenditures Forecast 2018
	(In millions)		
Regulated Distribution	$ 1,295	$ 1,325	$ 1,305
Regulated Transmission	1,000	1,000	1,000
Competitive Energy Services	540	370	300
Corporate/Other	90	95	90

Total	$ 2,925	$ 2,790	$ 2,695

Additionally, planned capital expenditures in 2019 for Regulated Distribution are approximately $1.3 billion while planned capital expenditures for Regulated Transmission are expected to be approximately $800 million to $1.2 billion annually in 2019 to 2021.

Forecasted capital expenditures for 2017 by operating company are shown in the following table:

	2017 Capital Expenditures Forecast
OE	$145
Penn	45
CEI	120
TE	45
JCP&L	355
ME	135
PN	160
MP	250
PE	125
WP	205
ATSI	420
TrAIL	65
MAIT	255
FES	325
AE Supply	50
Other	90
Total	$2,790

FirstEnergy's strategy is to focus on investments in its regulated operations. The centerpiece of this strategy is the Energizing the Future investment plan, which began as a $4.2 billion investment plan from 2014 through 2017 to upgrade and expand FirstEnergy's transmission system with additional investments of $800 million to $1.2 billion annually from 2018 through 2021. This program is focused on projects that enhance system performance, physical security and add operating flexibility and capacity starting with the ATSI system and moving east across FirstEnergy's service territory over time. Through 2015, FirstEnergy's capital expenditures under this plan were $2.4 billion and in 2016 capital expenditures under this plan are currently projected to be approximately $1 billion. In total, FirstEnergy has identified over $20 billion in transmission investment opportunities across the 24,000 mile transmission system, making this a continuing platform for investment in the years beyond 2021.

In alignment with FirstEnergy’s strategy to invest in its Regulated Transmission and Regulated Distribution segments and the repositioning of the CES segment, FirstEnergy is also focused on improving the balance sheet over time consistent with its business profile, maintaining investment grade metrics at its regulated businesses and FirstEnergy Corp. 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.

Any financing plans by FirstEnergy, including the issuance of equity, refinancing of maturing debt and reductions in short-term borrowings, are subject to market conditions and other factors, such as the impact of the current energy and capacity markets and potential credit rating changes. No assurance can be given that any such issuances, financings, refinancings, or reductions in short-term debt, as the case may be, will be completed as anticipated. Any delay in the completion of financing plans could require FE or FES or any of their subsidiaries to utilize short-term borrowing capacity, which would impact available liquidity. In addition, FirstEnergy expects to continually evaluate any planned financings, which may result in changes from time to time.

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As of September 30, 2016, 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, 2016, included the following:

Currently Payable Long-Term Debt	(In millions)
Unsecured notes	$ 680
FMBs	250
Unsecured PCRBs[1]	158
Collateralized lease obligation bonds	8
Sinking fund requirements	82
Other notes	38
	$ 1,216

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

Short-Term Borrowings

FirstEnergy had $2,975 million and $1,708 million of short-term borrowings as of September 30, 2016 and December 31, 2015, respectively. The $1,267 million increase in short-term borrowings during the first nine-months of 2016 was primarily due to pension contributions, debt redemptions, of which some may be refinanced in the future, and for general business purposes. FirstEnergy also had approximately $400 million of short-term investments at September 30, 2016 that were redeemed in early October to pay down a portion of the short-term borrowings. FirstEnergy's available liquidity as of November 1, 2016, was as follows:

Borrower(s)	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy[1]	Revolving	March 2019	$3,500	$ 1,241
FES / AE Supply	Revolving	March 2019	1,500	1,500
FET[2]	Revolving	March 2019	1,000	750
		Subtotal	$6,000	$ 3,491
		Cash	—	211
		Total	$6,000	$ 3,702

(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.

During September of 2016, the FES/AE Supply facility was amended to decrease FES's individual borrower sub-limit to $900 million from $1.5 billion and AE Supply's individual borrower sub-limit to $600 million from $1 billion. The lending banks' aggregate commitments under the FES/AE Supply facility remain at $1.5 billion.

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 sublimits 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, 2016:

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	—	900	—	—	(2)
AE Supply	—	600	—	—	(2)
FET	—	—	1,000	—	(1)
OE	500	—	—	500	(3)
CEI	500	—	—	500	(3)
TE	500	—	—	500	(3)
JCP&L	600	—	—	500	(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	—	—	100	(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 sublimit.

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, 2016, the borrowers were in compliance with the applicable debt to total capitalization ratios under the respective Facilities.

Term Loans

FE has a $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. 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, 2016, 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 FE to meet their short-term working capital requirements. A similar but separate arrangement exists among FirstEnergy's unregulated companies. FESC administers these two money pools and tracks surplus funds of FirstEnergy and the respective regulated and unregulated subsidiaries, as well as proceeds available from bank borrowings. Companies receiving a loan under the money pool agreements must repay the principal amount of the loan, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from their respective pool and is based on the average cost of funds available through the pool. The average interest rates for borrowings in the first nine months of 2016 were 0.67% per annum for the regulated companies' money pool and 1.94% per annum for the unregulated companies' money pool. Absent sufficient available funds from other companies in the unregulated money pool, borrowings by FES from such money pool may be funded by FE from borrowings under its revolving credit facility or cash on hand.

Pollution Control Revenue Bonds

In the third quarter of 2016, as discussed below, FG remarketed $86 million of fixed rate PCRBs and retired $12 million of variable interest rate PCRBs, which resulted in the elimination of LOCs related to $92 million of variable interest rate PCRBs that are no longer outstanding.

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. FirstEnergy is focused on improving its balance sheet and maintaining investment grade credit metrics at its regulated businesses and at FirstEnergy Corp. The following table displays FE's and its subsidiaries' credit ratings as of November 4, 2016:

	Senior Secured		Senior Unsecured		
Issuer	S&P	Moody's	S&P	Moody's	Fitch
FE	—	—	BB+	Baa3	BB+
FES	BB-	B1	B	Caa1	—
AE Supply	BB+	—	BB-	B1	—
AGC	—	—	BB-	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	—	A2	—	—	—
PE	BBB+	A3	—	—	—
TE	BBB+	Baa1	—	—	—
TrAIL	—	—	BBB-	A3	—
WP	BBB+	A2	—	—	—

On July 29, 2016, Moody's downgraded the Senior Unsecured debt rating for FES to Ba2 from Baa3, and for AE Supply to Ba1 from Baa3. At the same time Moody's affirmed the Baa2 Senior Secured debt rating for FES and the

Baa3 Senior Unsecured debt rating for AGC. FE's Baa3 Issuer Rating was unchanged. On November 4, 2016, Moody's further downgraded the Senior Unsecured debt rating for FES to Caa1, and for AE Supply to B1, and affirmed the Senior Unsecured debt rating for AGC at Baa3. At the same time Moody's downgraded the Senior Secured debt rating for FES to B1.

On August 1, 2016, S&P lowered the Senior Unsecured debt ratings for FES, AE Supply, and AGC to BB- from BBB-. S&P also downgraded the Senior Secured debt ratings for FES and AES to BB+ from BBB-. FE and its regulated utility subsidiaries BBB- Corporate Credit Ratings were affirmed. Additionally on November 4, 2016, S&P downgraded the Senior Unsecured debt rating for FES to B and Senior Secured debt rating to BB-.

Debt capacity is subject to the consolidated debt to total capitalization limits in the Facilities previously discussed. As of September 30, 2016, FE and its subsidiaries could issue additional debt of approximately $4 billion and remain within the limitations of the financial covenants required by the Facilities. As of September 30, 2016, FES' incremental debt capacity under its consolidated debt to total capitalization financial covenant is also $4 billion given FirstEnergy's consolidated debt to total capitalization ratio under its Facility.

Changes in Cash Position

As of September 30, 2016, FirstEnergy had $551 million of cash and cash equivalents compared to $131 million of cash and cash equivalents as of December 31, 2015. As of September 30, 2016 and December 31, 2015, FirstEnergy had approximately $44 million and $82 million, respectively, of restricted cash included in Other current assets on the Consolidated Balance Sheets.

Cash Flows From Operating Activities

FirstEnergy's most significant sources of cash are 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 $2,580 million during the first nine months of 2016 compared with $2,317 million provided from operating activities during the first nine months of 2015. Cash flows from operations increased $263 million in the first nine months of 2016, compared with the same period of 2015, primarily due to the following:

- Distribution rate increases associated with the implementation of new rates, partially offset by a year-over-year decline in distribution deliveries primarily resulting from lower average customer usage;
- Higher transmission revenue, reflecting recovery of incremental operating expenses and a higher rate base;
- Higher capacity revenues at CES, partially offset by a decline in sales volume; and
- Lower disbursements for fuel and purchased power resulting from the lower sales volumes.

Cash Flows From Financing Activities

In the first nine months of 2016, cash provided from financing activities was $316 million compared to $29 million of cash used for financing activities during the first nine months of 2015. The following table summarizes redemptions, repayments, short-term borrowings and dividends:

	For the Nine Months Ended September 30	
Securities Issued or Redeemed / Repaid	2016	2015
	(In millions)	
New Issues		
Term Loan	$—	$200
PCRBs	471	339
Unsecured Notes	—	250
FMBs	50	295
	$521	$1,084
Redemptions / Repayments		
Term Loan	$—	$(200)
PCRBs	(483)	(312)

Unsecured notes	(300)	—
FMBs	(145)	(145)
Senior secured notes	(89)	(124)
	$(1,017)	$(781)
Short-term borrowings, net	$1,275	$134
Common stock dividend payments	$(458)	$(455)

On May 1, 2016, JCP&L repaid $300 million of 5.625% senior unsecured notes at maturity.

On June 1 and July 1 of 2016, NG repurchased approximately $225 million and $60 million, respectively of PCRBs, which were subject to a mandatory put on such date. On August 15, 2016, NG remarketed the approximately $285 million of PCRBs with a fixed interest rate of 4.375% and mandatory put dates ranging from June 1, 2022 to July 1, 2022.

On July 11, 2016, Penn issued $50 million of 4.24% FMBs due 2056. Proceeds received from the issuance of the FMBs were used: (i) to fund capital expenditures; (ii) for working capital needs and other general business purposes; and (iii) to repay borrowings under the FirstEnergy regulated companies' money pool.

On August 15, 2016, WP repaid $145 million of 5.875% FMBs at maturity. Also on September 23, 2016, WP agreed to sell $475 million of new 3.84% FMBs due 2046 ($100 million), 4.09% FMBs due 2047 ($100 million) and 4.14% FMBs due 2047 ($275 million). The sales are expected to settle on December 15, 2016, September 15, 2017 and December 15, 2017, respectively. Proceeds to be received from the issuances of the FMBs are expected to be used: (i) for general corporate purposes; and (ii) to repay WP's currently outstanding $275 million of 5.95% FMBs that mature on December 15, 2017.

On August 15, 2016, FG remarketed approximately $86 million of PCRBs with fixed interest rates ranging from 4.25% to 4.50% and mandatory put dates ranging from May 1, 2021 to June 1, 2021.

On September 15, 2016, FG remarketed $100 million of PCRBs with a fixed interest rate of 4.25% and a mandatory put of September 15, 2021.

On September 15 and 30, 2016, respectively, FG retired an aggregate of $12 million of PCRBs with original maturity dates in 2018 and 2029.

On October 17, 2016, PE issued $155 million of 3.89% FMBs due 2046. Proceeds received from the issuance were used: (i) to repay short-term borrowings incurred to repay PE's $100 million of 5.80% FMBs that matured on October 15, 2016; and (ii) for general corporate purposes.

Cash Flows From Investing Activities

Cash used for investing activities in the first nine months of 2016 principally represented cash used for property additions. The following table summarizes investing activities for the first nine months of 2016 and the comparable period of 2015:

	For the Nine Months Ended September 30		
Cash Used for Investing Activities	2016	2015	Increase (Decrease)
	(In millions)		
Property Additions:			
Regulated Distribution	$878	$884	$ (6)
Regulated Transmission	755	700	55
Competitive Energy Services	492	400	92
Corporate / Other	31	41	(10)
Nuclear fuel	195	101	94
Investments	76	87	(11)
Asset removal costs	101	111	(10)
Other	(52)	(37)	(15)
	$2,476	$2,287	$ 189

Cash used for investing activities for the first nine months of 2016 increased $189 million, compared to the same period of 2015, primarily due to increases in nuclear fuel and property additions. Property additions increased due to higher transmission spend in New Jersey and CES' purchase of the remaining non-affiliated leasehold interest in Perry Unit 1. The increase in nuclear fuel was due to the scheduled Davis-Besse refueling and maintenance outage.

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, 2016, was approximately $3.4 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]	$ 28
Deferred compensation arrangements[2]	544
Other[3]	12
	584
Subsidiaries' Guarantees	
Energy and Energy-Related Contracts[4]	248
FES' guarantee of NG's nuclear property insurance	96
FES' guarantee of nuclear decommissioning costs	21
FES' guarantee of FG's sale and leaseback obligations	1,674
	2,039
FE's Guarantees on Behalf of Business Ventures	
Global Holding facility	300
Other Assurances	
Surety Bonds - Wholly Owned Subsidiaries	382
Surety Bonds	22
LOCs[5]	100
	504
Total Guarantees and Other Assurances	$ 3,427

(1) Issued for open-ended terms, with a 10-day termination right by FirstEnergy.
(2) CES related portion is $136 million.
(3) Includes guarantees of $4 million for nuclear decommissioning funding assurances, $4 million for railcar leases and $4 million for various leases.
(4) Includes energy and energy-related contracts associated with FES of approximately $248 million.
(5) Includes $9 million issued for various terms pursuant to LOC capacity available under FirstEnergy's revolving credit facilities, $87 million issued in connection with energy and energy related contracts, and $4 million pledged in connection with the sale and leaseback of Beaver Valley Unit 2 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, 2016, FES has posted collateral of $193 million and AE Supply has posted collateral of $4 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.

As a result of the downgrades by Moody's and S&P on July 29, 2016 and August 1, 2016, CES posted additional collateral of $53 million. Additionally, on November 4, 2016, Moody's and S&P further downgraded FES. Given the downgrades, CES has further potential collateral posting obligations totaling $81 million for which counterparties have not exercised their right to require CES to post collateral. Subsequent to the occurrence of a senior unsecured credit rating downgrade below S&P's and Moody's current ratings, or a “material adverse event,” the immediate posting of collateral or accelerated payments may be required of FirstEnergy. The following table discloses the additional credit contingent contractual obligations that may be required under certain events as of November 4, 2016:

Potential Collateral Obligations	CES	Regulated	Total
	(in millions)		
Contractual Obligations for Additional Collateral			
At Current Credit Rating	$81	$ —	$81
Upon Further Downgrade	—	48	48
Upon Material Adverse Event	10	—	10
Surety Bonds (Collateralized Amount)	264	96	360
Total Exposure from Contractual Obligations	$355	$ 144	$499

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, 2016, neither FES nor AE Supply had any collateral posted with their affiliates.

Other Commitments and Contingencies

FE 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 FE, Signal Peak, Global Rail, Global Mining Group, LLC and Global Coal Sales Group, LLC, each being a direct or indirect subsidiary of Global Holding, 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.

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 $895 million as of September 30, 2016, 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, 2016, FirstEnergy's leasehold interest was 2.60% of Beaver Valley Unit 2 and FES' leasehold interest was 93.83% of Bruce Mansfield Unit 1.

On May 23, 2016, NG completed the purchase of the 3.75% lessor equity interests of the remaining non-affiliated leasehold interest in Perry Unit 1 for $50 million. In addition, the Perry Unit 1 leases expired in accordance with their terms on May 30, 2016, resulting in NG being the sole owner of Perry Unit 1 and entitled to 100% of the unit's output.

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 assets and liabilities as of September 30, 2016 are summarized by year in the following table:

Source of Information- Fair Value by Contract Year	2016	2017	2018	2019	2020	Thereafter	Total
	(In millions)						
Prices actively quoted[1]	$(4)	$(1)	$—	$—	$—	$—	$(5)
Other external sources[2]	11	27	(5)	(30)	—	—	3
Prices based on models	(1)	5	—	—	(11)	—	(7)
Total[3]	$6	$31	$(5)	$(30)	$(11)	$—	$(9)

[1] Represents exchange traded New York Mercantile Exchange futures and options.
[2] Primarily represents contracts based on broker and ICE quotes.
[3] Includes $(118) million in non-hedge derivative contracts that are primarily related to NUG contracts at certain of the Utilities. 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, 2016, not subject to regulatory accounting, an increase in commodity prices of 10% would decrease net income by approximately $37 million during the next 12 months.

Equity Price Risk

As of September 30, 2016, the FirstEnergy pension plan assets were allocated approximately as follows: 42% in equity securities, 35% in fixed income securities, 9% 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, 2016, FirstEnergy made a $297 million contribution to its qualified pension plan. Additionally, in October 2016 FirstEnergy contributed $85 million to its qualified pension plan, including $50 million at FENOC. 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, 2016, FirstEnergy's pension plan assets earned approximately 11.5% as compared to an annual expected return on plan assets of 7.5%.

As of September 30, 2016, FirstEnergy's OPEB plans were invested in fixed income and equity securities. Through September 30, 2016 FirstEnergy's OPEB plans have earned approximately 5.8% as compared to an annual expected return on plan assets of 7.5%.

NDT funds have been established to satisfy NG’s and other FirstEnergy subsidiaries' nuclear decommissioning obligations. As of September 30, 2016, approximately 62% of the funds were invested in fixed income securities, 36% of the funds were invested in equity securities and 2% 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 $1,546 million, $908 million and $56 million for fixed income securities, equity securities and short-term investments, respectively, as of September 30, 2016, excluding $(8) million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $91 million reduction in fair value as of September 30, 2016. 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, 2016, FirstEnergy contributed approximately $2 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. FirstEnergy would anticipate a pre-tax mark-to-market loss (net of amounts capitalized) to be in the range of approximately \$300 million to \$525 million assuming a discount rate of approximately 4.00% to 3.75% for the pension plans and 3.75% to 3.50% for the OPEB plans, respectively, and a return on the pension and OPEB plans' assets of 11% based on actual investment performance through September 30, 2016.

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 CES' 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 and demand 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 $68 million, of which $38 million was incurred through September 30, 2016. 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.

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.

Pursuant to the NJBPU's March 26, 2015 final order in JCP&L's 2012 rate case proceeding directing that certain studies be completed, on July 22, 2015, the NJBPU approved the NJBPU staff's recommendation to implement such studies, which include operational and financial components. The independent consultant conducting the review issued a final report on July 27, 2016, recognizing that JCP&L is meeting the NJBPU requirements and making various operational and financial recommendations. The NJBPU issued an Order on August 24, 2016, that accepted the independent consultant’s final report and directed JCP&L, the Division of Rate Counsel, and other interested parties to address the recommendations.

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. The oral argument was held on October 25, 2016.

On April 28, 2016, JCP&L filed tariffs with the NJBPU proposing a general rate increase associated with its distribution operations that seeks to improve service and benefit customers by supporting equipment maintenance, tree trimming, and inspections of lines, poles and substations, while also compensating for other business and operating expenses. The filing requested approval to increase annual operating revenues by approximately $142.1 million based upon a hybrid test year for the twelve months ending June 30, 2016. On July 13, 2016, this matter was submitted to the Office of Administrative Law for hearing and the issuance of an Initial Decision. On September 30, 2016, JCP&L filed an update to its filing, which includes actual data for the twelve months ended June 30, 2016, requesting an increase to annual operating revenues by approximately $146.6 million. On October 19, 2016, an order was received approving the agreed upon procedural schedule. Hearings are scheduled to occur in January 2017 through March 2017. On November 2, 2016, JCP&L achieved a settlement-in-principle with all the intervening parties providing for an annual $80 million distribution revenue increase, which will take effect on January 1, 2017, subject to finalization, execution and NJBPU approval of a Stipulation of Settlement.

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. The procedural schedule was suspended while the NJBPU considered a motion on a legal issue regarding whether MAIT can be designated as a "public utility" in New Jersey. On February 24, 2016, the NJBPU issued an Order concluding that MAIT does not satisfy the “electricity distribution” element necessary for “public utility” status because MAIT would not own any electric distribution assets in New Jersey. On April 22, 2016, JCP&L and MAIT filed a supplemental petition and testimony seeking to include certain JCP&L distributions assets in the transfer to satisfy the "electricity distribution" element necessary for "public utility" status in accordance with the NJBPU’s February 24, 2016 order. In order to allow MAIT to file its formula transmission rate with an effective date of January 1, 2017, on September 8, 2016, JCP&L and MAIT submitted a letter to the NJBPU to withdraw their petition to transfer JCP&L assets into MAIT. The NJBPU administratively closed the matter on September 30, 2016. See Transfer of Transmission Assets to MAIT in FERC Matters below for further discussion of this transaction.

OHIO

On August 4, 2014, the Ohio Companies filed an application with the PUCO seeking approval of their ESP IV entitled Powering Ohio's Progress. ESP IV included a proposed Rider RRS, which would flow through to customers either charges or credits representing the net result of the price paid to FES through an eight-year FERC-jurisdictional PPA, referred to as the ESP IV PPA, against the revenues received from selling such output into the PJM markets. The Ohio Companies entered into stipulations which modified ESP IV and which included PUCO Staff as a signatory party, in addition to other signatories. On March 31, 2016, the PUCO issued an Opinion and Order adopting and approving the Ohio Companies’ stipulated ESP IV with modifications. FES and the Ohio Companies entered into the ESP IV PPA on April 1, 2016.

On January 27, 2016, certain parties filed a complaint with FERC against FES and the Ohio Companies requesting FERC review the ESP IV PPA under Section 205 of the FPA. On April 27, 2016, FERC issued an order granting the complaint, prohibiting any transactions under the ESP IV PPA pending future authorization by FERC, and directing FES to submit the ESP IV PPA for FERC review if the parties desired to transact under the agreement. FES and the Ohio Companies did not file the ESP IV PPA for FERC review but rather agreed to suspend the ESP IV PPA. FES and the Ohio Companies subsequently advised FERC of this course of action.

On April 29, 2016 and May 2, 2016, several parties, including the Ohio Companies, filed applications for rehearing on the Ohio Companies’ ESP IV with the PUCO. The Ohio Companies’ Application for Rehearing included a modified Rider RRS proposal but did not include a FERC-jurisdictional PPA. The PUCO accepted the applications for rehearing for further consideration and provided parties an opportunity to comment on the Ohio Companies’ Application for Rehearing and file an alternative proposal. PUCO Staff recommended that the PUCO deny the Ohio Companies’ modified Rider RRS proposal and recommended a new Rider DMR providing for the collection of $204 million annually (grossed up for income taxes) for three years with a possible extension for an additional two years. The Ohio Companies recommended that the PUCO approve the proposed modified Rider RRS and that a properly designed Rider DMR would be valued at $558 million annually for 8 years, and include an additional amount that recognizes the value of the economic impact of FirstEnergy maintaining its headquarters in Ohio.

Several parties subsequently filed protests and comments with FERC alleging, among other things, that the modified Rider RRS constitutes a "virtual PPA". The filings and FirstEnergy’s responses thereto are pending before FERC.

On September 6, 2016, while the applications for rehearing were still pending before the PUCO, the OCC and NOAC filed a notice of appeal with the Ohio Supreme Court appealing various PUCO and Attorney Examiner Entries on the parties’ applications for rehearing. On September 16, 2016, the Ohio Companies intervened and filed a motion to dismiss the appeal. The appeal remains pending before the Ohio Supreme Court.

On October 12, 2016, the PUCO issued an opinion and order ruling on the parties’ applications for rehearing and further modified ESP IV. The PUCO order denied the Ohio Companies’ modified Rider RRS proposal, and instead approved a Rider DMR proposed by PUCO Staff, with modifications.

As a result of the stipulations, the PUCO’s March 31, 2016 Opinion and Order and the PUCO’s October 12, 2016 order, the material terms of ESP IV include:

- An eight-year term (June 1, 2016 - May 31, 2024).
- The Rider DMR which provides for the Ohio Companies to collect $132.5 million annually for three years, with the possibility of a two-year extension. The Rider DMR will be grossed up for taxes, resulting in an approved amount of approximately $204 million annually. Revenues from the Rider DMR will be excluded from the significantly excessive earnings test for the initial three-year term but the exclusion will be reconsidered upon application for a potential two-year extension.
- Three conditions for continued recovery under the Rider DMR: (1) retention of the corporate headquarters and nexus of operations in Akron, Ohio; (2) no change in control of the Ohio Companies; and (3) a demonstration of sufficient progress in the implementation of grid modernization programs approved by the PUCO.
- No restrictions on the Ohio Companies’ use of funds collected under the Rider DMR. However, the PUCO directed the PUCO Staff to periodically review how the Ohio Companies and FE use the funds to ensure the funds are used, directly or indirectly, in support of grid modernization. Uses of funds to indirectly support grid modernization could include, e.g., reducing outstanding pension obligations or reducing debt.
- Continuation of a base distribution rate freeze through May 31, 2024.
- Continuation of the supply of power to non-shopping customers at a market-based price set through an auction process.
- Continuation of Rider DCR with increased revenue caps of approximately $30 million per year from June 1, 2016 through May 31, 2019; $20 million per year from June 1, 2019 through May 31, 2022; and $15 million per year from June 1, 2022 through May 31, 2024 that supports continued investment related to the distribution system for the benefit of customers.

- Collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs.
- Continuation of 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.
- Potential procurement of 100 MW of new Ohio wind or solar resources subject to a demonstrated need to procure new renewable energy resources as part of a strategy to further diversify Ohio's energy portfolio.
- An agreement to file a case with the PUCO by April 3, 2017, seeking to transition to decoupled base rates for residential customers.
- An agreement to file a Grid Modernization Business Plan for PUCO consideration and approval (which filing was made on February 29, 2016).
- A goal across FirstEnergy to reduce CO_2 emissions by 90% below 2005 levels by 2045.
- A contribution of $3 million per year ($24 million over the eight-year term) to fund energy conservation programs, economic development and job retention in the Ohio Companies service territory.
- Contributions of $2.4 million per year ($19 million over the eight-year term) to fund a fuel-fund in each of the Ohio Companies service territories to assist low-income customers.
- A contribution of $1 million per year ($8 million over the eight-year term) to establish a Customer Advisory Council to ensure preservation and growth of the competitive market in Ohio.

Finally, on March 21, 2016, a number of generation owners filed with FERC a complaint against PJM requesting that FERC expand the MOPR in the PJM Tariff to prevent the alleged artificial suppression of prices in the PJM capacity markets by state-subsidized generation, in particular alleged price suppression that could result from the ESP IV PPA and other similar agreements. The complaint requested that FERC direct PJM to initiate a stakeholder process to develop a long-term MOPR reform for existing resources that receive out-of-market revenue. This proceeding remains pending before FERC.

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 legislative amendments to the energy efficiency standards discussed below. 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 legislative amendments to the peak demand reduction standards discussed below.

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 the energy policy of the state. Legislation was introduced to address issues raised in the Energy Mandates Study Committee report, namely SB320 and HB554. SB320 proposes to freeze energy efficiency and renewable energy requirements for an additional four years at 2014 levels, as well as addressing net metering issues. HB554 proposes to freeze energy efficiency and renewable energy requirements through 2027 at 2014 levels.

On September 24, 2014, the Ohio Companies filed an amendment to their energy efficiency 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 and the matter remains pending before the PUCO.

On April 15, 2016, the Ohio Companies filed an application for approval of their three-year energy efficiency portfolio plans for the period from January 1, 2017 through December 31, 2019. The plans as proposed comply with benchmarks contemplated by SB310 and provisions of the ESP IV, and include a portfolio of energy efficiency programs targeted to a variety of customer segments, including residential customers, low income customers, small commercial customers, large commercial and industrial customers and governmental entities. The Ohio Companies anticipate the cost of the plans will be approximately $323 million over the life of the portfolio plans and such costs are expected to be recovered through the Ohio Companies' existing rate mechanisms. The hearing is scheduled for November 21-23, 2016.

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 was denied. On August 9, 2016, upon a Joint Application for Dismissal filed by the Ohio Companies, PUCO and the ELPC, the Ohio Supreme Court dismissed the appeal.

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 legislative amendments discussed above, 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 certain purchases arising from one auction and directed 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. On November 18, 2015, the PUCO ruled that on a going-forward basis, pass-through clauses may not be included in fixed-price contracts for all customer classes. On December 18, 2015, FES filed an Application for Rehearing seeking to change the ruling or have it only apply to residential and small commercial customers. On January 13, 2016, the PUCO granted reconsideration for further consideration of the matters specified in the applications for rehearing.

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. Following the expiration of the current DSPs, the Pennsylvania Companies will operate under new DSPs for the June 1, 2017 through May 31, 2019 delivery period, which would provide for the competitive procurement of generation supply for customers who do not choose an alternative EGS or for customers of alternative EGSs that fail to provide the contracted service. Under the programs, the supply would be provided by wholesale suppliers through a mix of 12 and 24-month energy contracts, as well as one RFP for 2-year SREC contracts for ME, PN and Penn. In addition, the plan includes modifications to the Pennsylvania Companies’ existing POR programs in order to reduce the level of uncollectible expense the Pennsylvania Companies experience associated with alternative EGS charges.

Pursuant to Pennsylvania's EE&C legislation (Act 129 of 2008) and PPUC orders, Pennsylvania EDCs implement energy efficiency and peak demand reduction programs. The Pennsylvania Companies' Phase II EE&C Plans were effective through May 31, 2016. Total Phase II costs of these plans were expected to be approximately $175 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' Phase III EE&C plans for the June 2016 through May 2021 period, which were approved in March 2016, are designed to achieve the targets established in the PPUC's Phase III Final Implementation Order without recovery to implement the 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. On February 11, 2016, the PPUC approved the Pennsylvania Companies' LTIIPs. On February 16, 2016, the Pennsylvania Companies filed DSIC riders for PPUC approval for quarterly cost recovery associated with the capital projects approved in the LTIIPs. On June 9, 2016, the PPUC approved the Pennsylvania Companies’ DSIC riders to be effective July 1, 2016, subject to hearings and refund or reallocation among customers.

On April 28, 2016, each of the Pennsylvania Companies filed tariffs with the PPUC proposing general rate increases associated with their distribution operations that will benefit customers by modernizing the grid with smart technologies, increasing vegetation management activities, and continuing other customer service enhancements. The filings request approval to increase annual operating revenues by approximately $140.2 million at ME, $158.8 million at PN, $42.0 million at Penn, and $98.2 million at WP, based upon fully projected future test years for the twelve months ending December 31, 2017 at each of the Pennsylvania Companies. As a result of the enactment of Act 40 of 2016 that terminated the practice of making a CTA when calculating a utility’s federal income taxes for ratemaking purposes, the Pennsylvania Companies submitted supplemental testimony on July 7, 2016, that quantified the value of the elimination of the CTA and outlined their plan for investing 50 percent of that amount in rate base eligible equipment as required by the new law. Formal settlement agreements for each of the Pennsylvania Companies were filed on October 14, 2016, which provide increases in annual operating revenues of approximately $96 million at ME, $100 million at PN, $29 million at Penn, and $66 million at WP, and are subject to PPUC approval. One item related to the calculation of DSIC rates was reserved for briefing, with briefs filed by two parties. The proposed new rates are expected to take effect in January 2017 pending regulatory approval, which is expected no later than January 26, 2017.

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. On March 4, 2016, a Joint Petition for Full Settlement was submitted to the PPUC for consideration and approval. On April 18, 2016, the ALJs issued an Initial Decision approving the Joint Petition for Full Settlement without modifications. On July 21, 2016, the PPUC adopted a Motion approving the Joint Petition for Full Settlement with minor modifications. On August 24, 2016, the PPUC issued a Final Order approving the Joint Settlement consistent with the July 21, 2016 Motion. See Transfer of Transmission Assets to MAIT in FERC Matters below for further discussion of this transaction.

WEST VIRGINIA

MP and PE provide electric service to all customers through traditional cost-based, regulated utility ratemaking. MP and PE recover net power supply costs, including fuel costs, purchased power costs and related expenses, net of related market sales revenue through the ENEC. MP's and PE's ENEC rate is updated annually.

MP and PE filed with the WVPSC on March 31, 2016 their Phase II energy efficiency program proposal for approval. MP and PE are proposing three energy efficiency programs to meet their Phase II requirement of energy efficiency reductions of 0.5% of 2013 distribution sales for the January 1, 2017 through May 31, 2018 period, as agreed to by MP and PE, and approved by the WVPSC in the 2012 proceeding approving the transfer of ownership of Harrison Power Station to MP. The costs for the program are expected to be $10.4 million and will be eligible for recovery through the existing energy efficiency rider which is reviewed in the fuel (ENEC) case each year. A unanimous settlement was reached by the parties on all issues and presented to the WVPSC on August 18, 2016. An order approving the settlement in full without modification was issued by the WVPSC on September 23, 2016. Under the order, the programs may begin as of the date of such order, but no later than January 1, 2017.

The Staff of the WVPSC and the Consumer Advocate Division filed a Show Cause petition on August 5, 2016, requesting the WVPSC order MP and PE to file and implement RFPs for all future capacity and energy requirements above 100 MWs and that they comply with an RFP settlement provision from the Harrison asset acquisition. MP and PE filed a timely response to the petition arguing for dismissal on September 7, 2016. On October 17, 2016, the WVPSC denied the petition filed by the Staff of the WVPSC and the Consumer Advocate Division and dismissed the case.

On August 16, 2016, MP and PE filed their annual ENEC case proposing an approximate $65 million annual increase in rates effective January 1, 2017, which is a 4.7% overall increase over existing rates. The $65 million increase is comprised of $119 million under-recovered balance as of June 30, 2016, and a projected $54 million over-recovery for the 2017 rate effective period. A hearing has been set for November 9 and 10, 2016 with an order expected to be issued in the fourth quarter of 2016.

On August 22, 2016, MP and PE filed an application for approval of a modernization and improvement plan for coal-fired boilers at electric power plants and cost-recovery surcharge proposing an approximate $6.9 million annual increase in rates proposed to be effective May 1, 2017, which is a 0.5% overall increase over existing rates. The filing is in response to recent legislation by the West Virginia Legislature session permitting accelerated recovery of costs related to modernizing and improving coal-fired boilers, including costs related to meeting environmental requirements and reducing emissions. The filing was supplemented on September 28, 2016, to add two additional projects, resulting in an approximate $7.4 million annual increase in rates. The Staff of the WVPSC has filed a motion to dismiss the case arguing the new statute was not meant to recover these types of projects, but the WVPSC has set the case for hearing for February 21-23, 2017.

On December 30, 2015, MP filed an IRP identifying a capacity shortfall starting in 2016 and exceeding 700 MW by 2020 and 850 MW by 2027. On June 3, 2016, the WVPSC accepted the IRP finding that IRPs are informational and that it must not approve or disapprove the IRP. MP Plans to issue a RFP to address its generation shortfall identified in the IRP by the end of the year.

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

Ohio ESP IV PPA

For information regarding matters before FERC related to the ESP IV PPA between FES and the Ohio Companies, see “Regulatory Matters - Ohio” above.

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. On June 15, 2016 various parties, including ATSI and the Utilities, filed a settlement agreement at FERC agreeing to apply a combined usage based/socialization approach to cost allocation for charges to transmission customers in the PJM region for transmission projects operating at or above 500 kV. Certain parties in the proceeding did not agree to the settlement and filed protests to the settlement seeking, among other issues, to strike certain of the evidence advanced by FirstEnergy and certain of the other settling parties in support of the settlement, as well as provided further comments in opposition to the settlement. The PJM TOs responded to the protesting parties' various pleadings and motions. The settlement is pending before FERC.

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 appealed these rulings to the U.S. Court of Appeals for the D.C. Circuit which, in a July 1, 2016 opinion, ruled that the PJM transmission owners failed to preserve their arguments in the legal proceedings before FERC and, on that basis, denied the appeal. In a related case brought by the Southwest Power Pool transmission owners and issued on the same day, the court ruled that the Mobile-Sierra standard does not protect transmission owners’ rights of first refusal that may be provided for in RTO tariffs because, according to the court, the tariff language is designed to block competition. The Mobile-Sierra standard presumes that rates negotiated by private parties at arm’s length are just and reasonable and prohibits FERC from modifying such rates unless the public interest requires.

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 transfer to PJM. 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. On March 17, 2016, FERC denied FirstEnergy's request for rehearing of FERC's earlier order rejecting the settlement agreement and affirmed its prior ruling that ATSI must submit the cost/benefit analysis.

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. On October 29, 2015, FERC issued an order finding that ATSI and the ATSI zone do not have to pay MISO MVP charges for the Michigan Thumb transmission project. MISO and the MISO TOs filed a request for rehearing, which FERC denied on May 19, 2016. On July 15, 2016, the MISO TOs filed an appeal of FERC's orders with the Sixth Circuit. FirstEnergy intervened in the proceedings and intends to participate in the appeal. 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 July 13, 2016, FERC issued its order finding it appropriate for MISO to assess an MVP usage charge for transmission exports from MISO to PJM. Various parties, including FirstEnergy and the PJM TOs, requested rehearing or clarification of FERC’s order. These parties' request for rehearing remains pending before FERC.

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 the proceedings that address the remaining open issues related to costs for the "Michigan Thumb" transmission project and "legacy RTEP" transmission projects cannot be predicted at this time.

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 law; (iv) MAIT's participation in FE's regulated companies' money pool; and (v) certain affiliated interest agreements. As initially proposed, it was expected that JCP&L, ME, and PN would contribute their transmission assets at net book value and an allocated portion of goodwill in a tax-free exchange to MAIT, which would 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. FERC approved the transaction on February 18, 2016. On August 24, 2016, the PPUC issued a Final Order approving the transaction. In order to allow MAIT to file its formula transmission rate with an effective date of January 1, 2017, on September 8, 2016, JCP&L and MAIT submitted a letter to the NJBPU to withdraw their petition to transfer JCP&L assets to MAIT. The NJBPU administratively closed the matter on September 30, 2016. See New Jersey and Pennsylvania in State Regulation above for further discussion of this transaction.

On October 14 and 28, 2016, MAIT submitted applications to FERC requesting authorization to issue equity, short-term debt, and long-term debt. MAIT intends to issue membership interests to FET, PN, and ME in exchange for their respective cash and asset contributions. MAIT is expected to issue short-term debt and participate in the FirstEnergy Utility Money Pool for working capital, to fund day-to-day operations, and for other general corporate purposes. Over the long-term, MAIT is expected to issue long-term debt to support capital investment and to establish an actual capital structure for ratemaking purposes. On October 28, 2016, MAIT submitted an application to FERC requesting authorization to implement a formula transmission rate to recover and earn a return on transmission costs effective January 1, 2017. On October 28, 2016, MAIT and PJM submitted joint applications to FERC requesting authorization for (i) ME and PN to withdraw from the PJM Consolidated Transmission Owners Agreement as TOs, and (ii) MAIT to become a participating PJM TO. Acceptance of MAIT as a PJM TO would grant PJM functional control over MAIT’s transmission assets, and would permit PJM to implement MAIT’s formula rate on MAIT’s behalf.

JCP&L Transmission Formula Rate

Given that JCP&L will not be transferring its transmission assets to MAIT, there is a need for JCP&L to update its transmission rate. Accordingly, on October 28, 2016, JCP&L submitted an application to FERC requesting authorization to implement a formula transmission rate to recover and earn a return on transmission costs effective January 1, 2017.

California Claims Litigation

Since 2002, AE Supply has been involved in litigation and claims based on its power sales to the California Energy Resource Scheduling division of the CDWR during 2001-2003. This litigation and claims are related to litigation and claims advanced by the California Attorney General and certain California utilities regarding alleged market manipulation of the wholesale energy markets in California during the 2000-2001 period. AE Supply negotiated a settlement with the California Attorney General and the California utilities and, on August 24, 2016, filed the settlement agreement for FERC approval. The settlement calls for AE Supply to pay, without admission of any liability, $3.6 million in settlement in principle of all remaining claims that are based on AE Supply's power sales in the western energy markets during the 2001-2003 time period. On October 27, 2016 FERC approved this settlement.

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, 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. On September 14, 2015, the ALJ issued his initial decision, disallowing recovery of certain costs. The initial decision and exceptions thereto remain 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, and on March 3, 2015, FERC issued Opinion No. 531-B affirming its prior rulings. Appeals of Opinion Nos. 531, 531-A and 531-B are pending before the U.S. Court of Appeals for the D.C. Circuit.

MISO Capacity Portability

On June 11, 2012, in response to certain arguments advanced by MISO, FERC requested comments regarding whether existing rules on transfer capability act as barriers to the delivery of capacity between MISO and PJM. FirstEnergy and other parties submitted filings arguing that MISO's concerns largely are without foundation, FERC did not mandate a solution in response to MISO's concerns. At FERC's direction, in May, 2015, PJM, MISO, and their respective independent market monitors provided additional information on their various joint issues surrounding the PJM/MISO seam to assist 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 remain 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.

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. The U.S. Court of Appeals for the D.C. Circuit ordered the EPA on July 28, 2015, to reconsider the CSAPR 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 CSAPR, but questioning whether EPA required upwind states to reduce emissions by more than their contribution to air pollution in downwind states. EPA issued a CSAPR update rule on September 7, 2016, reducing summertime NOx emissions from power plants in 22 states in the eastern U.S., including Ohio, Pennsylvania and West Virginia, beginning in 2017. Depending on how the EPA and the states implement CSAPR, the future cost of compliance may be material 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 EPA will designate those 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 material and changes to FirstEnergy’s and FES’ operations may result. In August 2016, the State of Delaware filed a CAA Section 126 petition with the EPA alleging that the Harrison generating facility's NOx emissions significantly contribute to Delaware's inability to attain the ozone NAAQS. The petition seeks a short term NOx emission rate limit of 0.125 lb/mmBTU over an averaging period of no more than 24 hours. On September 27, 2016, EPA extended the time frame for acting on the CAA Section 126 petition by six months to April 7, 2017. FirstEnergy is unable to predict the outcome of this matter or estimate the loss or range of loss.

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. FirstEnergy's total capital cost for compliance (over the 2012 to 2018 time period) is currently expected to be approximately $345 million (CES segment of $168 million and Regulated Distribution segment of $177 million), of which $267 million has been spent through September 30, 2016 ($117 million at CES and $150 million at Regulated Distribution).

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 event 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, all plants covered by this contract 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 under the contract through 2025. On May 31, 2016, the parties agreed to a stipulation that if FG’s force majeure defense is determined to be wholly or partially invalid, liquidated damages are the sole remedy available to BNSF and CSX. The arbitration panel has determined to consolidate the claims with a liability hearing scheduled to begin on November 28, 2016, and, if necessary, a damages hearing scheduled to begin on May 8, 2017. The decision on liability is expected to be issued within sixty days from the end of the liability hearing proceedings, which are scheduled to conclude February 24, 2017. 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. FG intends to vigorously assert its 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. Refer to the Strategic Review of Competitive Operations section of Note 1, Organization and Basis of Presentation, for possible actions that may be taken by FES in the event of an adverse outcome, including, without limitation, seeking protection under the bankruptcy laws. 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 FG fails 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 to the deactivated plant, 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, FG paid approximately $70 million in the aggregate in liquidated damages to settle delivery shortfalls in 2014 related to its deactivated plants, which approximated full liquidated damages under the agreements for such year related to the plant deactivations. Liquidated damages for the period 2015-2025 remain in dispute.

As to a specific coal supply agreement, AE Supply has asserted termination rights effective in 2015. In response to notification of the termination, the coal supplier commenced litigation alleging AE Supply does not have sufficient justification to terminate the agreement. AE Supply has filed an answer denying any liability related to the termination. This matter is currently in the discovery phase of litigation and no trial date has been established. There are approximately 5.5 million tons remaining under the contract for delivery. At this time, AE Supply 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, March 27, 2013 and October 18, 2017, 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 loss or range of loss.

Climate Change

FirstEnergy has established a goal to reduce CO_2 emissions by 90% below 2005 levels by 2045. 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.

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 (which have been stayed by the U.S. Supreme Court), 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 two-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. Numerous states and private parties filed appeals and motions to sta