FIRSTENERGY CORP
Form 10-Q
July 28, 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 June 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 JUNE 30, 2016
FirstEnergy Corp., $0.10 par value	425,198,228
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® online store. FirstEnergy also uses Twitter® and Facebook® as additional channels of distribution to reach public investors and as a supplemental means of disclosing material non-public information for complying with its disclosure obligations under SEC Regulation FD. Information contained on FirstEnergy's 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, related to continued depressed wholesale energy and capacity markets, including the potential need to deactivate or sell 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 certain older regulated and competitive fossil 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 material accounting policies.
- The ability to access the public securities and other capital and credit markets in accordance with our financial plans, the cost of such capital and overall condition of the capital and credit markets affecting us and our subsidiaries.
- Actions that may be taken by credit rating agencies that could negatively affect us and/or our subsidiaries' access to financing, increase the costs thereof, and increase requirements to post additional collateral to support outstanding commodity positions, LOCs and other financial guarantees.
- Changes in national and regional economic conditions affecting us, our subsidiaries and/or our major industrial and commercial customers, and other counterparties with which we do business, including fuel suppliers.
- The impact of any changes in tax laws or regulations or adverse tax audit results or rulings.
- Issues concerning the stability of domestic and foreign financial institutions and counterparties with which we do business.
- The risks associated with cyber-attacks 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 nuclear generating facilities
FES	FirstEnergy Solutions Corp., which provides energy-related products and services
FESC	FirstEnergy Service Company, which provides legal, financial and other corporate support services
FET	FirstEnergy Transmission, LLC, formerly known as Allegheny Energy Transmission, LLC which is the parent of ATSI, TrAIL and MAIT, and has a joint venture in PATH.
FEV	FirstEnergy Ventures Corp., which invests in certain unregulated enterprises and business ventures
FG	FirstEnergy Generation, LLC, a wholly owned subsidiary of FES, which owns and operates non-nuclear generating facilities
FirstEnergy	FirstEnergy Corp., together with its consolidated subsidiaries
Global Holding	Global Mining Holding Company, LLC, a joint venture between FEV, WMB Marketing Ventures, LLC and Pinesdale LLC
Global Rail	A subsidiary of Global Holding that owns coal transportation operations near Roundup, Montana
JCP&L	Jersey Central Power & Light Company, a New Jersey electric utility operating subsidiary
MAIT	Mid-Atlantic Interstate Transmission, LLC, a subsidiary of FET, formed to own and operate transmission facilities
ME	Metropolitan Edison Company, a Pennsylvania electric utility operating subsidiary
MP	Monongahela Power Company, a West Virginia electric utility operating subsidiary
NG	FirstEnergy Nuclear Generation, LLC, a subsidiary of FES, which owns nuclear generating facilities
OE	Ohio Edison Company, an Ohio electric utility operating subsidiary
Ohio Companies	CEI, OE and TE
PATH	Potomac-Appalachian Transmission Highline, LLC, a joint venture between FE and a subsidiary of AEP
PATH-Allegheny	PATH Allegheny Transmission Company, LLC
PATH-WV	PATH West Virginia Transmission Company, LLC
PE	The Potomac Edison Company, a Maryland 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.
ARO	Asset Retirement Obligation

GLOSSARY OF TERMS, Continued

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
DR	Demand Response
DSIC	Distribution System Improvement Charge
DSP	Default Service Plan
EDC	Electric Distribution Company
EE&C	Energy Efficiency and Conservation
EGS	Electric Generation Supplier
ELPC	Environmental Law & Policy Center
EmPOWER Maryland	EmPower Maryland Energy Efficiency Act
ENEC	Expanded Net Energy Cost
EPA	United States Environmental Protection Agency
ERO	Electric Reliability Organization
ESP	Electric Security Plan
ESP IV PPA	Unit Power Agreement entered into on April 1, 2016 by and between the Ohio Companies and FES
ESP IV PPA Facilities	100% of the output of the W. H. Sammis plant, 100% of the output of the Davis-Besse Nuclear Power Station and FES' 4.85% entitlement in OVEC
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
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
RGGI	Regional Greenhouse Gas Initiative
ROE	Return on Equity

GLOSSARY OF TERMS, Continued

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 June 30 2016	2015	For the Six Months Ended June 30 2016	2015
REVENUES:				
Regulated Distribution	$2,200	$2,239	$4,721	$4,801
Regulated Transmission	264	269	539	507
Unregulated businesses	937	957	2,010	2,054
Total revenues*	3,401	3,465	7,270	7,362
OPERATING EXPENSES:				
Fuel	438	383	819	896
Purchased power	889	989	2,013	2,102
Other operating expenses	964	900	1,882	1,957
Provision for depreciation	334	322	663	641
Amortization of regulatory assets, net	63	59	124	91
General taxes	241	242	521	511
Impairment of assets (Note 2)	1,447	16	1,447	16
Total operating expenses	4,376	2,911	7,469	6,214
OPERATING INCOME (LOSS)	(975)	554	(199)	1,148
OTHER INCOME (EXPENSE):				
Investment income (loss)	19	(3)	47	14
Interest expense	(289)	(282)	(577)	(561)
Capitalized financing costs	26	33	51	67
Total other expense	(244)	(252)	(479)	(480)
INCOME (LOSS) BEFORE INCOME TAXES (BENEFITS)	(1,219)	302	(678)	668
INCOME TAXES (BENEFITS)	(130)	115	83	259
NET INCOME (LOSS)	$(1,089)	$187	$(761)	$409
EARNINGS (LOSSES) PER SHARE OF COMMON STOCK:				
Basic	$(2.56)	$0.44	$(1.79)	$0.97
Diluted	$(2.56)	$0.44	$(1.79)	$0.97
WEIGHTED AVERAGE NUMBER OF SHARES OUTSTANDING:				
Basic	425	422	424	422

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

* Includes excise tax collections of $92 million and $96 million in the three months ended June 30, 2016 and 2015, respectively, and $199 million and $211 million in the six months ended June 30, 2016 and 2015, respectively.

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

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

	For the Three Months Ended June 30		For the Six Months Ended June 30	
(In millions)	2016	2015	2016	2015
NET INCOME (LOSS)	$(1,089)	$187	$(761)	$409
OTHER COMPREHENSIVE INCOME (LOSS):				
Pension and OPEB prior service costs	(18)	(32)	(36)	(63)
Amortized losses on derivative hedges	2	1	4	2
Change in unrealized gains on available-for-sale securities	35	(14)	63	(10)
Other comprehensive income (loss)	19	(45)	31	(71)
Income taxes (benefits) on other comprehensive income (loss)	7	(17)	11	(27)
Other comprehensive income (loss), net of tax	12	(28)	20	(44)
COMPREHENSIVE INCOME (LOSS)	$(1,077)	$159	$(741)	$365

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)	June 30, 2016	December 31, 2015
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$199	$ 131
Receivables-		
Customers, net of allowance for uncollectible accounts of $63 in 2016 and $69 in 2015	1,341	1,415
Other, net of allowance for uncollectible accounts of $3 in 2016 and $5 in 2015	153	180
Materials and supplies	759	785
Prepaid taxes	280	135
Derivatives	161	157
Collateral	20	70
Other	163	167
	3,076	3,040
PROPERTY, PLANT AND EQUIPMENT:		
In service	50,367	49,952
Less — Accumulated provision for depreciation	15,295	15,160
	35,072	34,792
Construction work in progress	2,389	2,422
	37,461	37,214
INVESTMENTS:		
Nuclear plant decommissioning trusts	2,456	2,282
Other	527	506
	2,983	2,788
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill (Note 2)	5,618	6,418
Regulatory assets	1,187	1,348
Other	1,076	1,286
	7,881	9,052
	$51,401	$ 52,094
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$1,327	$ 1,166
Short-term borrowings	2,925	1,708
Accounts payable	938	1,075
Accrued taxes	439	519
Accrued compensation and benefits	341	334
Derivatives	102	106
Other	687	694
	6,759	5,602
CAPITALIZATION:		
Common stockholders’ equity-		
Common stock, $0.10 par value, authorized 490,000,000 shares - 425,198,228 and 423,560,397 shares outstanding as of June 30, 2016 and December 31, 2015, respectively	42	42

Other paid-in capital	9,984	9,952
Accumulated other comprehensive income	191	171
Retained earnings	1,190	2,256
Total common stockholders’ equity	11,407	12,421
Noncontrolling interest	—	1
Total equity	11,407	12,422
Long-term debt and other long-term obligations	18,348	19,099
	29,755	31,521
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	6,888	6,773
Retirement benefits	4,177	4,245
Asset retirement obligations	1,448	1,410
Deferred gain on sale and leaseback transaction	774	791
Adverse power contract liability	181	197
Other	1,419	1,555
	14,887	14,971
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 12)		
	$51,401	$ 52,094

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

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FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	For the Six Months Ended June 30	
(In millions)	2016	2015
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income (loss)	$(761)	$409
Adjustments to reconcile net income (loss) to net cash from operating activities-		
Depreciation and amortization, including nuclear fuel, regulatory assets, net, and customer intangible asset amortization	922	869
Deferred purchased power and other costs	(33)	(45)
Deferred income taxes and investment tax credits, net	72	219
Impairment of assets (Note 2)	1,447	16
Investment impairments	10	24
Deferred costs on sale leaseback transaction, net	24	24
Retirement benefits	31	(16)
Pension trust contributions	(160)	(143)
Commodity derivative transactions, net (Note 9)	5	(7)
Lease payments on sale and leaseback transaction	(94)	(102)
Changes in current assets and liabilities-		
Receivables	101	8
Prepayments and other current assets	(91)	(116)
Accounts payable	(22)	(245)
Accrued taxes	(80)	(23)
Accrued compensation and benefits	(50)	12
Other current liabilities	17	2
Cash collateral, net	21	38
Other	101	66
Net cash provided from operating activities	1,460	990
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Long-term debt	—	200
Short-term borrowings, net	1,225	1,109
Redemptions and Repayments-		
Long-term debt	(581)	(292)
Common stock dividend payments	(305)	(303)
Other	36	(2)
Net cash provided from financing activities	375	712
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(1,492)	(1,486)
Nuclear fuel	(188)	(97)
Sales of investment securities held in trusts	1,024	819
Purchases of investment securities held in trusts	(1,073)	(881)
Asset removal costs	(63)	(67)
Other	25	19

Net cash used for investing activities	(1,767)	(1,693)
Net change in cash and cash equivalents	68	9
Cash and cash equivalents at beginning of period	131	85
Cash and cash equivalents at end of period	$199	$94

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

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

	For the Three Months Ended June 30		For the Six Months Ended June 30	
(In millions)	2016	2015	2016	2015
STATEMENTS OF OPERATIONS				
REVENUES:				
Electric sales to non-affiliates	$958	$914	$1,965	$1,989
Electric sales to affiliates	102	157	249	412
Other	42	48	87	95
Total revenues	1,102	1,119	2,301	2,496
OPERATING EXPENSES:				
Fuel	228	191	393	421
Purchased power from affiliates	167	77	249	147
Purchased power from non-affiliates	266	392	643	935
Other operating expenses	369	337	609	750
Provision for depreciation	84	81	167	161
General taxes	19	25	45	54
Impairment of assets (Note 2)	540	16	540	16
Total operating expenses	1,673	1,119	2,646	2,484
OPERATING INCOME (LOSS)	(571)	—	(345)	12
OTHER INCOME (EXPENSE):				
Investment income	19	1	32	14
Miscellaneous income	1	4	3	4
Interest expense — affiliates	(1)	(2)	(3)	(4)
Interest expense — other	(37)	(37)	(73)	(74)
Capitalized interest	8	9	18	18
Total other expense	(10)	(25)	(23)	(42)
LOSS BEFORE INCOME TAX BENEFITS	(581)	(25)	(368)	(30)
INCOME TAX BENEFITS	(143)	(4)	(61)	(6)
NET LOSS	$(438)	$(21)	$(307)	$(24)
STATEMENTS OF COMPREHENSIVE LOSS				
NET LOSS	$(438)	$(21)	$(307)	$(24)
OTHER COMPREHENSIVE INCOME (LOSS):				
Pension and OPEB prior service costs	(3)	(4)	(7)	(8)
Amortized gains on derivative hedges	(1)	(1)	(1)	(2)

Change in unrealized gains on available-for-sale securities	33	(12)	56	(9)
Other comprehensive income (loss)	29	(17)	48	(19)
Income taxes (benefits) on other comprehensive income (loss)	12	(6)	19	(7)
Other comprehensive income (loss), net of tax	17	(11)	29	(12)
COMPREHENSIVE LOSS	$(421)	$(32)	$(278)	$(36)

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)	June 30, 2016	December 31, 2015
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$2	$ 2
Receivables-		
Customers, net of allowance for uncollectible accounts of $7 in 2016 and $8 in 2015	225	275
Affiliated companies	411	451
Other, net of allowance for uncollectible accounts of $3 in 2016 and 2015	37	59
Notes receivable from affiliated companies	—	11
Materials and supplies	430	470
Derivatives	155	154
Collateral	20	70
Prepayments and other	81	66
	1,361	1,558
PROPERTY, PLANT AND EQUIPMENT:		
In service	13,992	14,311
Less — Accumulated provision for depreciation	5,706	5,765
	8,286	8,546
Construction work in progress	1,061	1,157
	9,347	9,703
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,510	1,327
Other	10	10
	1,520	1,337
DEFERRED CHARGES AND OTHER ASSETS:		
Customer intangibles	52	61
Goodwill (Note 2)	—	23
Property taxes	20	40
Derivatives	83	79
Other	377	367
	532	570
	$12,760	$ 13,168
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$439	$ 512
Short-term borrowings-		
Affiliated companies	210	—
Other	—	8
Accounts payable-		
Affiliated companies	360	542
Other	114	139
Accrued taxes	78	76
Derivatives	99	104
Other	173	181
	1,473	1,562

CAPITALIZATION:		
Common stockholder's equity-		
Common stock, without par value, authorized 750 shares - 7 shares outstanding as of June 30, 2016 and December 31, 2015	3,643	3,613
Accumulated other comprehensive income	75	46
Retained earnings	1,639	1,946
Total common stockholder's equity	5,357	5,605
Long-term debt and other long-term obligations	2,347	2,510
	7,704	8,115
NONCURRENT LIABILITIES:		
Deferred gain on sale and leaseback transaction	774	791
Accumulated deferred income taxes	627	600
Retirement benefits	344	332
Asset retirement obligations	877	831
Derivatives	46	38
Other	915	899
	3,583	3,491
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 12)		
	$12,760	$ 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)

	For the Six Months Ended June 30	
(In millions)	2016	2015
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$(307)	$(24)
Adjustments to reconcile net loss to net cash from operating activities-		
Depreciation and amortization, including nuclear fuel and customer intangible asset amortization	281	278
Deferred costs on sale and leaseback transaction, net	24	24
Deferred income taxes and investment tax credits, net	(16)	50
Investment impairments	9	22
Commodity derivative transactions, net (Note 9)	5	(7)
Lease payments on sale and leaseback transaction	(94)	(102)
Impairment of assets (Note 2)	540	16
Changes in current assets and liabilities-		
Receivables	110	277
Materials and supplies	12	(9)
Prepayments and other current assets	(13)	(9)
Accounts payable	(79)	(259)
Accrued taxes	2	(23)
Accrued compensation and benefits	(6)	1
Other current liabilities	22	17
Cash collateral, net	50	89
Other	16	2
Net cash provided from operating activities	556	343
CASH FLOWS FROM FINANCING ACTIVITIES:		
New financing-		
Short-term borrowings, net	210	124
Redemptions and repayments-		
Long-term debt	(245)	(69)
Other	(2)	(2)
Net cash (used for) provided from financing activities	(37)	53
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(335)	(264)
Nuclear fuel	(188)	(97)
Sales of investment securities held in trusts	441	376
Purchases of investment securities held in trusts	(467)	(404)
Cash investments	11	—
Loans to affiliated companies, net	11	(13)
Other	8	6
Net cash used for investing activities	(519)	(396)

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.

FirstEnergy and its subsidiaries are principally involved in the generation, transmission, and distribution of electricity. FirstEnergy’s ten utility operating companies comprise one of the nation’s largest investor-owned electric systems, based on serving six million customers in the Midwest and Mid-Atlantic regions. Its generation subsidiaries control nearly 17,000 MW of capacity from a diverse mix of non-emitting nuclear, scrubbed coal, natural gas, hydroelectric and other renewables. FirstEnergy’s transmission operations include approximately 24,000 miles of lines and 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 June 30, 2016 and 2015, Capitalized financing costs on FirstEnergy's Consolidated Statements of Income (Loss) include $9 million and $14 million, respectively, of allowance for equity funds used during construction and $17 million and $19 million, respectively, of capitalized interest. For the six months ended

June 30, 2016 and 2015, Capitalized financing costs on FirstEnergy's Consolidated Statements of Income (Loss) include $17 million and $30 million, respectively, of allowance for equity funds used during construction and $34 million and $37 million, respectively, of capitalized interest.

During the second quarter of 2015, FirstEnergy and FES recognized an impairment charge of $16 million associated with certain transportation equipment. 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.

New Accounting Pronouncements

In May 2014, the FASB issued, ASU 2014-09 "Revenue from Contracts with Customers", requiring entities to recognize revenue by applying a five-step model in accordance with the core principle to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In addition, the accounting for costs to obtain or fulfill a contract with a customer is specified and disclosure requirements for revenue recognition are expanded. In August 2015, the FASB issued a final ASU deferring the effective date until fiscal years beginning after December 15, 2017. Earlier application is permitted only as of annual reporting periods beginning after December 15, 2016, (the original effective date). In March 2016, the FASB issued ASU 2016-08, “Principal versus Agent Considerations (Reporting Revenue Gross versus Net)", clarifying the principal versus agent implementation guidance in the following areas: unit of account at which the principal/agent determination is made; applying the control principle to certain types of transactions and the control principle and principal/agent indicators. In April 2016, the FASB issued ASU 2016-10, “Identifying Performance Obligations and Licensing”, clarifying the identification of performance obligations and the licensing implementation guidance. In May 2016, the FASB issued ASU 2016-11, “Rescission of SEC Guidance Because of Accounting Standards Updates 2014-09 and 2014-16 Pursuant to Staff Announcements at the March 3, 2016 EITF Meeting", rescinding certain SEC Staff Observer comments that are codified in Topic 605, Revenue Recognition, and Topic 932, Extractive Activities-Oil and Gas, effective upon adoption of Topic 606. In May 2016, FASB issued ASU 2016-12 "Narrow-Scope Improvements and Practical Expedients", which is intended to not change the core principle of the guidance in Topic 606, but rather affect only the narrow aspects of Topic 606 by reducing the potential for diversity in practice at initial application and by reducing the cost and complexity of applying Topic 606 both at transition and on an ongoing basis. 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 FirstEnergy or its subsidiaries. See Note 7, Variable Interest Entities, for additional information.

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 will elect 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 for interim periods with 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.

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)",and
- ASU 2016-07, "Simplifying the Transition to the Equity Method of Accounting".

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 of these decisions, 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. Deactivation of these units is subject to review by PJM. 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.

Goodwill

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). The impairment is included within the caption Impairment of assets in the Consolidated Statement of Income (Loss).

The changes in the carrying amount of goodwill for the six months ended June 30, 2016 were as follows:

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 June 30, 2016	$5,092	$ 526	$ —	$ 5,618

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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 June 30		For the Six Months Ended June 30	
Reconciliation of Basic and Diluted Earnings per Share of Common Stock	2016	2015	2016	2015
Net income (loss)	$(1,089)	$187	$(761)	$409
Weighted average number of basic shares outstanding	425	422	424	422
Assumed exercise of dilutive stock options and awards(1)	—	1	—	1
Weighted average number of diluted shares outstanding	425	423	424	423
Basic earnings (losses) per share of common stock	$(2.56)	$0.44	$(1.79)	$0.97
Diluted earnings (losses) per share of common stock	$(2.56)	$0.44	$(1.79)	$0.97

(1) For both the three and six months ended June 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 both the three and six months ended June 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

In 2016, FirstEnergy has minimum required funding obligations of $381 million to its qualified pension plan, of which $245 million has been contributed through July 2016, including $85 million at FES in July of 2016. FirstEnergy expects to make future contributions to the qualified pension plan in 2016 to satisfy its remaining 2016 funding obligations, as well as address certain of its future funding obligations, with cash, up to $500 million of equity or a combination thereof, depending on, among other things, market conditions.

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 June 30	2016	2015	2016	2015
	(In millions)			
Service costs	$48	$48	$1	$1
Interest costs	99	96	8	7
Expected return on plan assets	(100)	(111)	(8)	(8)
Amortization of prior service costs (credits)	2	2	(20)	(34)
Net periodic costs (credits)	$49	$35	$(19)	$(34)

Components of Net Periodic Benefit Costs (Credits)	Pension		OPEB	
For the Six Months Ended June 30	2016	2015	2016	2015
	(In millions)			
Service costs	$96	$96	$2	$2

Interest costs	199	192	15	14
Expected return on plan assets	(197)	(222)	(16)	(16)
Amortization of prior service costs (credits)	4	4	(40)	(67)
Net periodic costs (credits)	$102	$70	$(39)	$(67)

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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 June 30	$6	$ 4	$(4)	$(5)
For the Six Months Ended June 30	12	8	(8)	(10)

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

Net Periodic Benefit Expense (Credit)	Pension		OPEB	
For the Three Months Ended June 30	2016	2015	2016	2015
	(In millions)			
FirstEnergy	$35	$ 24	$(15)	$(22)
FES	6	4	(4)	(4)

Net Periodic Benefit Expense (Credit)	Pension		OPEB	
For the Six Months Ended June 30	2016	2015	2016	2015
	(In millions)			
FirstEnergy	$72	$ 49	$(30)	$(45)
FES	12	8	(8)	(8)

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5. ACCUMULATED OTHER COMPREHENSIVE INCOME

The changes in AOCI, net of tax, in the three and six months ended June 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 April 1, 2016	$(32)	$ 36	$ 175	$179
Other comprehensive income before reclassifications	—	47	—	47
Amounts reclassified from AOCI	2	(12)	(18)	(28)
Other comprehensive income (loss)	2	35	(18)	19
Income taxes (benefits) on other comprehensive income (loss)	1	13	(7)	7
Other comprehensive income (loss), net of tax	1	22	(11)	12
AOCI Balance as of June 30, 2016	$(31)	$ 58	$ 164	$191
AOCI Balance as of April 1, 2015	$(36)	$ 28	$ 238	$230
Other comprehensive loss before reclassifications	—	(7)	—	(7)
Amounts reclassified from AOCI	1	(7)	(32)	(38)
Other comprehensive income (loss)	1	(14)	(32)	(45)
Income taxes (benefits) on other comprehensive income (loss)	1	(5)	(13)	(17)
Other comprehensive loss, net of tax	—	(9)	(19)	(28)
AOCI Balance as of June 30, 2015	$(36)	$ 19	$ 219	$202

	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	—	88	—	88
Amounts reclassified from AOCI	4	(25)	(36)	(57)
Other comprehensive income (loss)	4	63	(36)	31
Income taxes (benefits) on other comprehensive income (loss)	2	23	(14)	11
Other comprehensive income (loss), net of tax	2	40	(22)	20
AOCI Balance as of June 30, 2016	$(31)	$ 58	$ 164	$191

AOCI Balance as of January 1, 2015	$(37)	$ 25	$ 258	$246
Other comprehensive income before reclassifications	—	7	—	7
Amounts reclassified from AOCI	2	(17)	(63)	(78)
Other comprehensive income (loss)	2	(10)	(63)	(71)
Income taxes (benefits) on other comprehensive income (loss)	1	(4)	(24)	(27)
Other comprehensive income (loss), net of tax	1	(6)	(39)	(44)
AOCI Balance as of June 30, 2015	$(36)	$ 19	$ 219	$202

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

	For the Three Months Ended June 30		For the Six Months Ended June 30		Affected Line Item in Consolidated Statements of Income (Loss)
Reclassifications from AOCI[2]	2016	2015	2016	2015	
	(In millions)				
Gains & losses on cash flow hedges					
Commodity contracts	$—	$(1)	$—	$(2)	Other operating expenses
Long-term debt	2	2	4	4	Interest expense
	2	1	4	2	Total before taxes
	(1)	(1)	(2)	(1)	Income taxes (benefits)
	$1	$—	$2	$1	Net of tax
Unrealized gains on AFS securities					
Realized gains on sales of securities	$(12)	$(7)	$(25)	$(17)	Investment income (loss)
	4	2	9	6	Income taxes (benefits)
	$(8)	$(5)	$(16)	$(11)	Net of tax
Defined benefit pension and OPEB plans					
Prior-service costs	$(18)	$(32)	$(36)	$(63)	[1]
	7	13	14	24	Income taxes (benefits)
	$(11)	$(19)	$(22)	$(39)	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 six months ended June 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 April 1, 2016	$(9)	$ 30	$ 37	$58
Other comprehensive income before reclassifications	—	44	—	44
Amounts reclassified from AOCI	(1)	(11)	(3)	(15)
Other comprehensive income (loss)	(1)	33	(3)	29
Income taxes (benefits) on other comprehensive income (loss)	—	13	(1)	12
Other comprehensive income (loss), net of tax	(1)	20	(2)	17
AOCI Balance as of June 30, 2016	$(10)	$ 50	$ 35	$75
AOCI Balance as of April 1, 2015	$(8)	$ 24	$ 40	$56
Other comprehensive loss before reclassifications	—	(7)	—	(7)
Amounts reclassified from AOCI	(1)	(5)	(4)	(10)
Other comprehensive loss	(1)	(12)	(4)	(17)
Income tax benefits on other comprehensive loss	—	(4)	(2)	(6)
Other comprehensive loss, net of tax	(1)	(8)	(2)	(11)
AOCI Balance as of June 30, 2015	$(9)	$ 16	$ 38	$45

	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	—	80	—	80
Amounts reclassified from AOCI	(1)	(24)	(7)	(32)
Other comprehensive income (loss)	(1)	56	(7)	48
Income taxes (benefits) on other comprehensive income (loss)	—	22	(3)	19
Other comprehensive income (loss), net of tax	(1)	34	(4)	29
AOCI Balance as of June 30, 2016	$(10)	$ 50	$ 35	$75

AOCI Balance as of January 1, 2015	$(7)	$ 21	$ 43	$57
Other comprehensive income before reclassifications	—	6	—	6
Amounts reclassified from AOCI	(2)	(15)	(8)	(25)
Other comprehensive loss	(2)	(9)	(8)	(19)
Income tax benefits on other comprehensive loss	—	(4)	(3)	(7)
Other comprehensive loss, net of tax	(2)	(5)	(5)	(12)
AOCI Balance as of June 30, 2015	$(9)	$ 16	$ 38	$45

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

	For the Three Months Ended June 30		For the Six Months Ended June 30		Affected Line Item in Consolidated Statements of Operations
Reclassifications from AOCI[2]	2016	2015	2016	2015	
	(In millions)				
Gains & losses on cash flow hedges					
Commodity contracts	$(1)	$(1)	$(1)	$(2)	Other operating expenses
	—	—	—	—	Income tax benefits
	$(1)	$(1)	$(1)	$(2)	Net of tax
Unrealized gains on AFS securities					
Realized gains on sales of securities	$(11)	$(5)	$(24)	$(15)	Investment income
	4	2	9	6	Income tax benefits
	$(7)	$(3)	$(15)	$(9)	Net of tax
Defined benefit pension and OPEB plans					
Prior-service costs	$(3)	$(4)	$(7)	$(8)	[1]
	1	2	3	3	Income tax benefits
	$(2)	$(2)	$(4)	$(5)	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 June 30, 2016 and 2015 was 10.7% and 38.1%, respectively. FirstEnergy’s effective tax rate for the six months ended June 30, 2016 and 2015 was (12.2)% and 38.8%, respectively. The change in the effective tax rate for both periods is primarily due to the 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 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 in the second quarter of 2016 as well as certain statutory limitations on the utilization of state and local NOL carryforwards.

FES’ effective tax rate for the three months ended June 30, 2016 and 2015 was 24.6% and 16.0%, respectively. FES’ effective tax rate for the six months ended June 30, 2016 and 2015 was 16.6% and 20.0%, respectively. The change in the effective tax rate for both periods is primarily due to valuation allowances of $65 million recorded against state and local NOL carryforwards that management believes, more likely than not, will not be realized as described above as well as the impairment of goodwill, 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 June 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 June 30, 2016 and December 31, 2015, $350 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 June 30, 2016 and December 31, 2015, $108 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 June 30, 2016 and December 31, 2015, $418 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.
- Power Purchase Agreements - FirstEnergy evaluated its power purchase agreements and determined that certain NUG entities at its Regulated Distribution segment may be VIEs to the extent that they own a plant that sells substantially all of its output to the applicable utilities and the contract price for power is correlated with the plant's variable costs of production.

FirstEnergy maintains 14 long-term power purchase agreements with NUG entities that were entered into pursuant to PURPA. FirstEnergy was not involved in the creation of, and has no equity or debt invested in, any of these entities. FirstEnergy has determined that for all but one of these NUG entities, it does not have a variable interest in the entities or the entities do not meet the criteria to be considered a VIE. FirstEnergy may hold a variable interest in the remaining one entity; however, it applied the scope exception that exempts enterprises unable to obtain the necessary information to evaluate entities.

Because FirstEnergy has no equity or debt interests in the NUG entities, its maximum exposure to loss relates primarily to the above-market costs incurred for power. FirstEnergy expects any above-market costs incurred at its Regulated Distribution segment to be recovered from customers. Purchased power costs related to the contracts that may contain a variable interest during the three months ended June 30, 2016 and 2015 were $25 million and $27 million, respectively, and $56 million and $58 million during the six months ended June 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 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 June 30, 2016, FirstEnergy's leasehold interest was 2.60% of Beaver Valley Unit 2 and 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 units 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 June 30, 2016:

	Maximum	Net

	Exposure	Discounted Lease Payments, net	Exposure
	(In millions)		
FirstEnergy	$1,123	$ 880	$ 243
FES	1,094	872	222

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

FirstEnergy primarily applies the market approach for recurring fair value measurements using the best information available. Accordingly, FirstEnergy maximizes the use of observable inputs and minimizes the use of unobservable inputs. There were no changes in valuation methodologies used as of June 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 six months ended June 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	June 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	$—	$1,206	$—	$1,206	$—	$1,245	$—	$1,245
Derivative assets - commodity contracts	12	214	—	226	4	224	—	228
Derivative assets - FTRs	—	—	17	17	—	—	8	8
Derivative assets - NUG contracts[1]	—	—	1	1	—	—	1	1
Equity securities[2]	770	—	—	770	576	—	—	576
Foreign government debt securities	—	73	—	73	—	75	—	75
U.S. government debt securities	—	189	—	189	—	180	—	180
U.S. state debt securities	—	247	—	247	—	246	—	246
Other[3]	199	231	—	430	105	212	—	317
Total assets	$981	$2,160	$18	$3,159	$685	$2,182	$9	$2,876
Liabilities								
Derivative liabilities - commodity contracts	$(3)	$(137)	$—	$(140)	$(9)	$(122)	$—	$(131)
Derivative liabilities - FTRs	—	—	(8)	(8)	—	—	(13)	(13)
Derivative liabilities - NUG contracts[1]	—	—	(124)	(124)	—	—	(137)	(137)
Total liabilities	$(3)	$(137)	$(132)	$(272)	$(9)	$(122)	$(150)	$(281)
Net assets (liabilities)[4]	$978	$2,023	$(114)	$2,887	$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 $7 million as of June 30, 2016 and December 31, 2015, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

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Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG contracts and FTRs that are classified as Level 3 in the fair value hierarchy for the periods ended June 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 loss	—	(11)	(11)	—	(1)	(1)
Purchases	—	—	—	15	(7)	8
Settlements	—	24	24	(6)	13	7
June 30, 2016 Balance	$1	$ (124)	$(123)	$17	$ (8)	$9

(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 June 30, 2016:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$ 9	Model	RTO auction clearing prices	($2.60) to $6.60	$1.00	Dollars/MWH
NUG Contracts	$ (123)	Model	Generation	400 to 3,430,000	719,000	MWH
			Regional electricity prices	$33.80 to $33.90	$33.80	Dollars/MWH

FES

Recurring Fair Value Measurements	June 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	$—	$698	$—	$698	$—	$678	$—	$678
Derivative assets - commodity contracts	12	214	—	226	4	224	—	228
Derivative assets - FTRs	—	—	12	12	—	—	5	5
Equity securities[1]	495	—	—	495	378	—	—	378
Foreign government debt securities	—	57	—	57	—	59	—	59
U.S. government debt securities	—	60	—	60	—	23	—	23
U.S. state debt securities	—	4	—	4	—	4	—	4
Other[2]	—	192	—	192	—	184	—	184

Total assets	$507	$1,225	$12	$1,744	$382	$1,172	$5	$1,559
Liabilities								
Derivative liabilities - commodity contracts	$(3)	$(137)	$—	$(140)	$(9)	$(122)	$—	$(131)
Derivative liabilities - FTRs	—	—	(5)	(5)	—	—	(11)	(11)
Total liabilities	$(3)	$(137)	$(5)	$(145)	$(9)	$(122)	$(11)	$(142)
Net assets (liabilities)[(3)]	$504	$1,088	$7	$1,599	$373	$1,050	$(6)	$1,417

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(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 $4 million and $1 million as of June 30, 2016 and December 31, 2015, respectively, of receivables, payables, taxes and accrued income associated with the financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of FTRs held by FES and classified as Level 3 in the fair value hierarchy for the periods ended June 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 loss	—	(1)	(1)
Purchases	9	(4)	5
Settlements	(2)	11	9
June 30, 2016 Balance	$12	$ (5)	$ 7

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 June 30, 2016:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$ 7	Model	RTO auction clearing prices	($2.60) to $6.60	$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 June 30, 2016 and December 31, 2015:

	June 30, 2016[1]			December 31, 2015[2]		
	Cost Basis	Unrealized Gains	Fair Value	Cost Basis	Unrealized Gains	Fair Value
	(In millions)					
Debt securities						
FirstEnergy	$1,698	$ 62	$1,760	$1,778	$ 16	$1,794
FES	820	41	861	801	9	810
Equity securities						
FirstEnergy	$681	$ 89	$770	$542	$ 34	$576
FES	434	61	495	354	24	378

(1) Excludes short-term cash investments: FE Consolidated - $176 million; FES - $154 million.
(2) Excludes short-term cash investments: FE Consolidated - $157 million; FES - $139 million.

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 six months ended June 30, 2016 and 2015 were as follows:

For the Three Months Ended

June 30, 2016	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	$559	$ 34	$ (24)	$(2)	$ 25
FES	303	25	(15)	(2)	13

June 30, 2015	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	$448	$ 42	$ (39)	$(17)	$ 25
FES	187	32	(27)	(16)	15

For the Six Months Ended

June 30, 2016	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income

	(In millions)				
FirstEnergy	$1,024	$ 95	$ (73)	$(10)	$ 48
FES	441	67	(43)	(9)	26

June 30, 2015	Sale Proceeds	Realized Gains	Realized Losses	OTTI	Interest and Dividend Income
	(In millions)				
FirstEnergy	$819	$ 102	$ (89)	$(24)	$ 50
FES	376	70	(55)	(22)	29

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Held-To-Maturity Securities

Unrealized gains (there were no unrealized losses) and approximate fair values of investments in held-to-maturity securities as of June 30, 2016 and December 31, 2015 are immaterial to FirstEnergy. Investments in employee benefit trusts and equity method investments totaling $273 million as of June 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:

	June 30, 2016		December 31, 2015	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
FirstEnergy	$19,664	$21,627	$20,244	$21,519
FES	2,791	2,884	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 June 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 $12 million as of June 30, 2016 and $11 million as of 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 $37 million and $42 million as of June 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 six months ended June 30, 2016 and 2015.

As of June 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 June 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 $15 million and $20 million as of June 30, 2016 and December 31, 2015, respectively. During the next twelve months, approximately $9 million of unamortized gains are expected to be amortized to interest expense. Amortization of unamortized gains included in long-term debt totaled approximately $3 million during the three months ended June 30, 2016 and 2015. Amortization of unamortized gains included in long-term debt totaled approximately $6 million during the six months ended June 30, 2016 and 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 June 30, 2016, FirstEnergy's net asset position under commodity derivative contracts was $86 million, which related to FES positions. Under these commodity derivative contracts, FES posted $6 million of collateral and received $3 million of collateral. Certain commodity derivative contracts include credit risk related contingent features that would require FES to post $4 million of additional collateral if the credit rating for its debt were to fall below investment grade.

Based on commodity derivative contracts held as of June 30, 2016, an increase in commodity prices of 10% would decrease net income by approximately $33 million during the next twelve months.

NUGs

As of June 30, 2016, FirstEnergy's net liability position under NUG contracts was $123 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 June 30, 2016, FirstEnergy's and FES' FTR position was a $9 million and $7 million net asset, respectively, and FES posted $10 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 FirstEnergy’s utilities are recorded as regulatory assets or liabilities. Directly allocated FTRs are accounted for under the accrual method of accounting, and their effects are included in earnings at the time of contract performance.

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

Derivative Assets	Fair Value		Derivative Liabilities	Fair Value	
	June 30, 2016	December 31, 2015		June 30, 2016	December 31, 2015
	(In millions)			(In millions)	
Current Assets - Derivatives			Current Liabilities - Derivatives		
Commodity Contracts	$144	$ 150	Commodity Contracts	$(94)	$ (94)
FTRs	17	7	FTRs	(8)	(12)
	161	157		(102)	(106)
Deferred Charges and Other Assets - Other			Noncurrent Liabilities - Adverse Power Contract Liability		
			NUGs[(1)]	(124)	(137)
Commodity Contracts	82	78	Noncurrent Liabilities - Other		
FTRs	—	1	Commodity Contracts	(46)	(37)
NUGs[(1)]	1	1	FTRs	—	(1)
	83	80		(170)	(175)
Derivative Assets	$244	$ 237	Derivative Liabilities	$(272)	$ (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		
June 30, 2016	Fair Value	Derivative Instruments	Cash Collateral (Received)/Pledged	Net Fair Value
	(In millions)			
Derivative Assets				
Commodity contracts	$226	$(128)	$ (3)	$95
FTRs	17	(8)	—	9
NUG contracts	1	—	—	1
	$244	$(136)	$ (3)	$105
Derivative Liabilities				
Commodity contracts	$(140)	$128	$ 2	$(10)
FTRs	(8)	8	—	—

NUG contracts	(124)	—	—	(124)
	$(272)	$136	$ 2	$(134)

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December 31, 2015	Fair Value	Amounts Not Offset in Consolidated Balance Sheet		Net Fair Value
		Derivative Instruments	Cash Collateral (Received)/Pledged	
	(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 June 30, 2016:

	Purchases	Sales	Net	Units
	(In millions)			
Power Contracts	11	46	(35)	MWH
FTRs	55	—	55	MWH
NUGs	4	—	4	MWH
Natural Gas	61	—	61	mmBTU

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

	For the Three Months Ended June 30		
	Commodity Contracts	FTRs	Total
	(In millions)		
2016			
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense[1]	$(79)	$ 9	$(70)
Realized Gain (Loss) Reclassified to:			
Revenues[1]	$59	$ 1	$60
Purchased Power Expense[1]	(37)	—	(37)
Other Operating Expense[1]	—	(9)	(9)

[1] All amounts are associated with FES.

	For the Three Months Ended June 30		
	Commodity Contracts	FTRs	Total
	(In millions)		
2015			
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense[2]	$11	$ (2)	$9
Realized Gain (Loss) Reclassified to:			
Revenues[2]	$8	$ 8	$16
Purchased Power Expense[2]	(25)	—	(25)
Other Operating Expense[2]	—	(13)	(13)
Fuel Expense	(5)	—	(5)

[2] All amounts are associated with FES.

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2016	For the Six Months Ended June 30 Commodity Contracts	FTRs	Total
	(In millions)		
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense[1]	$(17)	$12	$(5)
Realized Gain (Loss) Reclassified to:			
Revenues[1]	$130	$3	$133
Purchased Power Expense[1]	(83)	—	(83)
Other Operating Expense[1]	—	(22)	(22)
Fuel Expense	(7)	—	(7)

[1] All amounts are associated with FES.

2015	For the Six Months Ended June 30 Commodity Contracts	FTRs	Total
	(In millions)		
Unrealized Gain (Loss) Recognized in:			
Other Operating Expense[2]	$22	$(15)	$7
Realized Gain (Loss) Reclassified to:			
Revenues[3]	$7	$45	$52
Purchased Power Expense[4]	(28)	—	(28)
Other Operating Expense[4]	—	(26)	(26)
Fuel Expense	(21)	—	(21)

[2] Includes $22 million for commodity contracts and $(14) million for FTRs associated with FES.
[3] Includes $7 million for commodity contracts and $44 million for FTRs associated with FES.
[4] All amounts are 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 six months ended June 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 June 30		
Derivatives Not in a Hedging Relationship with Regulatory Offset	NUGs	Regulated FTRs	Total
	(In millions)		
Outstanding net liability as of April 1, 2016	$(135)	$ (2)	$(137)
Purchases	—	4	4
Settlements	11	2	13
Outstanding net asset (liability) as of June 30, 2016	$(124)	$ 4	$(120)
Outstanding net asset (liability) as of April 1, 2015	$(148)	$ 1	$(147)
Unrealized loss	(8)	—	(8)
Purchases	—	12	12
Settlements	16	(1)	15
Outstanding net asset (liability) as of June 30, 2015	$(140)	$ 12	$(128)

	For the Six Months Ended June 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	(12)	—	(12)
Purchases	—	4	4
Settlements	24	(1)	23
Outstanding net asset (liability) as of June 30, 2016	$(124)	$ 4	$(120)
Outstanding net asset (liability) as of January 1, 2015	$(151)	$ 11	$(140)
Unrealized gain (loss)	(16)	1	(15)
Purchases	—	12	12
Settlements	27	(12)	15
Outstanding net asset (liability) as of June 30, 2015	$(140)	$ 12	$(128)

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. 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 June 30, 2016 and December 31, 2015 were as follows:

	2016	2015

	(In millions)	
FirstEnergy	$2,456	$2,282
FES	$1,510	$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	(13)	(12)
Liabilities incurred	4	32
Accretion	47	26
Balance, June 30, 2016	$1,448	$877

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 and related nuclear decommissioning trust 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.

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 for that three-year period, of which $32 million was incurred through June 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 is expected to complete its review in the third quarter of 2016.

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

On 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. JCP&L requested that the proposed new rates take effect in January 2017. On July 13, 2016, this matter was submitted to the Office of Administrative Law for hearing and the issuance of an Initial Decision. A procedural schedule has not yet been issued.

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. On July 18, 2016, the procedural schedule was set with evidentiary hearings in late October and early November of 2016. See Transfer of Transmission Assets to MAIT in FERC Matters below for further discussion of this transaction.

OHIO

The Ohio Companies operated under their ESP 3 plan which expired on May 31, 2016. On May 18, 2016, in response to previous appeals, the Supreme Court of Ohio issued its Opinion affirming in all respects the PUCO's ESP 3 Order.

The Ohio Companies filed an application with the PUCO on August 4, 2014 seeking approval of their ESP IV entitled Powering Ohio's Progress. The Ohio Companies filed a Stipulation and Recommendation on December 22, 2014, and supplemental stipulations and recommendations on May 28, 2015, and June 4, 2015. On December 1, 2015, the Ohio Companies filed a Third Supplemental Stipulation and Recommendation, which included PUCO Staff as a signatory party in addition to other signatories.

The material terms of ESP IV, as modified by the stipulations included:

- An eight-year term (June 1, 2016 - May 31, 2024);
- Contemplates continuing a base distribution rate freeze through May 31, 2024;
- An Economic Stability Program that flows through charges or credits through Rider RRS representing the net result of the price paid to FES through an eight-year FERC-jurisdictional PPA, referred to as the ESP IV PPA, for the output of the ESP IV PPA Facilities against the revenues received from selling such output into the PJM markets;
- Continuing to provide power to non-shopping customers at a market-based price set through an auction process;
- Continuing Rider DCR with increased revenue caps of approximately $30 million per year 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;
- A risk-sharing mechanism that would provide guaranteed credits under Rider RRS in years five through eight to customers as follows: $10 million in year five, $20 million in year six, $30 million in year seven and $40 million in year eight;

- A continuing commitment not to recover from retail customers certain costs related to transmission cost allocations for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of such costs avoided by customers for certain types of products totals $360 million, including such costs from MISO along with such costs from PJM, subject to the outcome of certain FERC proceedings;
- 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 by February 29, 2016, 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; and
- A contribution of $1 million per year ($8 million over the eight-year term) to establish a Customary Advisory Council to ensure preservation and growth of the competitive market in Ohio.

On March 31, 2016, the PUCO issued an Opinion and Order adopting and approving, with modifications, the Ohio Companies' ESP IV. Certain changes arising from the approval of ESP IV went into effect on June 1, 2016. The PUCO's modifications of ESP IV, among others, included:

- Limiting average customer bill amounts for the first two years of the plan, subject to certain exceptions, and permitting deferral for the second year;
- Prohibiting recovery of retirement costs of the ESP IV PPA Facilities through Rider RRS;
- Assigning the burden of capacity performance penalties incurred by the ESP IV PPA Facilities to the Ohio Companies, rather than customers, and to provide that all capacity performance bonuses earned by the ESP IV PPA Facilities be retained by the Ohio Companies, rather than customers; and
- Providing for the modification of the severability provision previously included in ESP IV, to also address potential future PJM Tariff or rule changes prohibiting the Ohio Companies from offering output of the ESP IV PPA Facilities into PJM auctions.

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 companies desired to transact under the agreement. Pursuant to FERC's directives in the order, FES and the Ohio Companies submitted required compliance filings. FES and the Ohio Companies did not file the ESP IV PPA for FERC review, but rather agreed to suspend the ESP IV PPA prior to transacting thereunder, pending the outcome of the PUCO and FERC proceedings.

On April 29, 2016 and May 2, 2016, applications for rehearing on the Ohio Companies ESP IV were filed with the PUCO by several parties, including the Ohio Companies. As part of the Ohio Companies' application for rehearing, the Ohio Companies proposed a modified Rider RRS. The PUCO issued an Entry on Rehearing on May 11, 2016 granting the applications for rehearing for the purpose of further consideration of the matters raised therein. On June 29, 2016, PUCO Staff filed testimony recommending that the Ohio Companies' modified Rider RRS proposal be denied, and instead recommended a new Distribution Modernization Rider providing for the collection of $131 million annually for three years with a possible extension for an additional two years. The hearing began on July 11, 2016 for the modified Rider RRS proposal. On July 25, 2016, the Ohio Companies filed testimony that continues to recommend that the PUCO approve the proposed modified Rider RRS and that the revenues and expenses of the proposed modified Rider RRS be excluded from the significantly excessive earnings test. The Ohio Companies' filing also provided testimony that a properly designed Distribution Modernization Rider would be valued at $558 million annually for 8 years, include an additional amount, as determined by the PUCO, that recognizes the value of the economic impact of FirstEnergy maintaining its headquarters in Ohio, and would also be excluded from the significantly excessive earnings test.

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

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 an order by May 1, 2016, so the revised rule could be in effect for the May 2016 BRA, and also 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. FERC took no action on the complaint prior to the BRA, and therefore the proposed MOPR was not in effect for the auction. Subsequently, certain municipal and industrial customers and a regulated utility, not affiliated with the Ohio Companies, filed a motion to dismiss the complaint as moot in light of FERC’s April 27, 2016 orders on, among other things, the ESP IV PPA and the resulting suspension of the ESP IV PPA. 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. A hearing in this matter has been scheduled for October 11, 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. The matter has been scheduled for oral argument on August 17, 2016.

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.

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.

On November 3, 2015, the Pennsylvania Companies filed their 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. A hearing was held on February 25, 2016. A Joint Petition for Settlement resolving all issues was filed on April 1, 2016 and was approved by the PPUC on May 19, 2016.

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 filed their Phase III EE&C plans for the June 2016 through May 2021 period on November 23, 2015, which are designed to achieve the targets established in the PPUC's Phase III Final Implementation Order. EDCs are permitted to recover costs for implementing their EE&C plans. On February 10, 2016, the Pennsylvania Companies and the parties intervening in the PPUC's Phase III proceeding filed a joint settlement resolving all issues, which was subject to PPUC approval. On March 10, 2016, the PPUC entered an Opinion and Order approving the settlement and directing that the Pennsylvania Companies modify certain cost recovery methodologies to describe the allocation of EE&C Phase III common costs among customer classes and to describe the recovery of remaining costs of their Phase II EE&C Plans. None of the parties to the joint settlement elected to withdraw from the joint settlement due to the modifications. On May 24, 2016, the PPUC issued a Secretarial Letter permitting the as filed EE&C rates for the Pennsylvania Companies to become effective on June 1, 2016.

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. A procedural schedule has been set with hearings commencing on September 6, 2016. The proposed new rates are expected to take effect in January 2017, pending regulatory approval.

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. A final order consistent with the Motion is expected in the near future. 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 $9.9 million and would be recovered through the existing energy efficiency rider which is reviewed in the fuel (ENEC) case each year. A hearing is scheduled to commence on August 18, 2016. MP and PE are requesting WVPSC approval by October 1, 2016 so MP and PE can implement the programs beginning January 1, 2017.

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, to which the settling parties, including ATSI and the Utilities, responded on July 15, 2016. On July 15, 2016, and July 25, 2016, the protesting parties filed 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 intend to submit responses to the motions to strike, and to the further comments of the protesting parties.

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 expects to intervene and 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. FirstEnergy and the other PJM TOs are evaluating whether to seek rehearing of FERC’s order.

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

The outcome of 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. If approved, JCP&L, ME, and PN will contribute their transmission assets at net book value and an allocated portion of goodwill in a tax-free exchange to MAIT, which will operate similar to FET's two existing stand-alone transmission subsidiaries, ATSI and TrAIL. MAIT's transmission facilities will remain under the functional control of PJM, and PJM will provide transmission service using these facilities under the PJM Tariff. FERC approved the transaction on February 18, 2016. The PPUC approved the transaction on July 21, 2016, subject to the entry of a final order. Upon receipt of all applicable regulatory approvals with respect to the transfer, MAIT expects to file a Section 204 application with FERC, and other necessary filings with the PPUC and the NJBPU, seeking authorization to issue equity to FET, JCP&L, PN and ME for their respective contributions, and to issue debt. MAIT will also make a Section 205 formula rate application with FERC to establish its transmission rate. See New Jersey and Pennsylvania in State Regulation above for further discussion of this transaction.

California Claims Litigation

In October 2006, several California governmental and utility parties presented AE Supply with a settlement proposal to resolve alleged overcharges for power sales by AE Supply to the California Energy Resource Scheduling division of the CDWR during 2001. The settlement proposal claims that CDWR is owed approximately $190 million for these alleged overcharges. This proposal was made in the context of mediation efforts by FERC and the Ninth Circuit in several pending proceedings to resolve all outstanding refund and other claims, including claims of alleged price manipulation in the California energy markets during 2000 and 2001. The Ninth Circuit had previously remanded one of those proceedings to FERC, which dismissed the claims of the California parties in May 2011. The California parties appealed FERC's decision back to the Ninth Circuit. AE Supply joined with other intervenors in the case and filed a brief in support of FERC's dismissal of the case. On April 29, 2015, the Ninth Circuit remanded the case to FERC for further proceedings. On November 3, 2015, FERC set for hearing and settlement procedures the remanded issue of whether any individual public utility seller’s violation of FERC’s market-based rate quarterly reporting requirement led to an unjust and unreasonable rate for that particular seller in California during the 2000-2001 period. Settlement discussions under a FERC-appointed settlement judge are ongoing. On March 1, 2016, FERC issued an order on rehearing clarifying the scope of the evidentiary hearing and the standard of review on remand. In particular, FERC clarified that certain bilateral transactions, including those of AE Supply to the California parties, are protected by the Mobile-Sierra standard, which requires a demonstration of harm to the public interest to determine liability and obligation to make refunds. The California parties requested rehearing of FERC’s March 1, 2016 order; FERC's order on rehearing remains pending. The California Parties also appealed FERC’s November 3, 2015, and March 1, 2016 orders to the Ninth Circuit, which has stayed its review pending the outcome of the ongoing proceeding discussed above.

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

The outcome of either of the above matters or estimate of loss or range of loss cannot be predicted at this time.

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 June 30, 2016, FirstEnergy's outstanding guarantees and other assurances aggregated approximately $3.5 billion, consisting of parental guarantees ($590 million), subsidiaries' guarantees ($2.0 billion), other guarantees ($300 million) and other assurances ($597 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 June 30, 2016, FES has posted collateral of $145 million.

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

Subsequent to the occurrence of a senior unsecured credit rating downgrade to below S&P's BBB- and Moody's Baa3, or a “material adverse event,” the immediate posting of collateral or accelerated payments may be required of FE or its subsidiaries. The following table discloses the additional credit contingent contractual obligations that may be required under certain events as of June 30, 2016:

Collateral Provisions	FES/ AE Supply (Tied to FE Corp. Rating) (In millions)	FES/ AE Supply (Tied to FES Rating)	Utilities	Total
Split Rating (One rating agency's rating below investment grade)	$ 25	$ 174	$ 44	$ 243
Non-Investment Grade Ratings (All Rating Agencies at or below BB+/Ba1)	$ 25	$ 187	$ 44	$ 256
Total Exposure from Contractual Obligations	$ 25	$ 310	$ 44	$ 379

Excluded from the preceding table are the potential collateral obligations due to affiliate transactions between the Regulated Distribution segment and CES segment. As of June 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 proposed a CSAPR update rule on November 16, 2015, that would reduce summertime NOx emissions from power plants in 23 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.

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 $253 million has been spent through June 30, 2016 ($108 million at CES and $145 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 that excuses FG's performance under its coal transportation contract with these parties. Specifically, the dispute arises from a contract for the transportation by BNSF and CSX of a minimum of 3.5 million tons of coal annually through 2025 to certain coal-fired power plants owned by FG that are located in Ohio. As a result of and in compliance with MATS, those plants were deactivated by April 16, 2015. In January 2012, FG notified BNSF and CSX that MATS constituted a force majeure event under the contract that excused FG's further performance. Separately, on August 4, 2015, BNSF and CSX submitted to the AAA office in Washington, D.C., a demand for arbitration and statement of claim against FG alleging that FG breached the contract and that FG's declaration of a force majeure under the contract is not valid and seeking damages 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 expected to begin in November 2016, and, if necessary, a damages hearing is expected to begin in May 2017. The decision on liability is expected to be issued within sixty days from the end of the liability hearings. FirstEnergy and FES continue to believe that MATS constitutes a force majeure event under the contract as it relates to the deactivated plants and that FG's performance under the contract is therefore excused. FirstEnergy and FES intend to vigorously assert their position in the arbitration proceedings. If, however, the arbitration panel rules in favor of BNSF and CSX, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. FirstEnergy and FES are unable to estimate the loss or range of loss.

FG is also a party to another coal transportation contract covering the delivery of 2.5 million tons annually through 2025, a portion of which is to be delivered to another coal-fired plant owned by FG that was deactivated as a result of MATS. FG has asserted a defense of force majeure in response to delivery shortfalls to such plant under this contract as well. If FirstEnergy and FES fail to reach a resolution with the applicable counterparties to the contract, and if it were ultimately determined that, contrary to FirstEnergy's and FES' belief, the force majeure provisions of that contract do not excuse the delivery shortfalls 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 of 2015-2025 remain in dispute.

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

In September 2007, AE received an NOV from the EPA alleging NSR and PSD violations under the CAA, as well as Pennsylvania and West Virginia state laws at the coal-fired Hatfield's Ferry and Armstrong plants in Pennsylvania and the coal-fired Fort Martin and Willow Island plants in West Virginia. The EPA's NOV alleges equipment replacements during maintenance outages triggered the pre-construction permitting requirements under the NSR and PSD programs. On June 29, 2012, January 31, 2013, and March 27, 2013, EPA issued CAA section 114 requests for the Harrison coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2007. On December 12, 2014, EPA issued a CAA section 114 request for the Fort Martin coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2009. FirstEnergy intends to comply with the CAA but, at this time, is unable to predict the outcome of this matter or estimate the 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, 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 must be ratified by at least 55 countries representing at least 55% of global GHG emissions before its non-binding obligations to limit global warming to well below two degrees Celsius become effective. 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 unexpected, changes in timing and closure plan requirements in the future could impact our asset retirement obligations significantly.

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 June 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 $124 million have been accrued through June 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 June 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. 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.

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 related to the Shield Building analysis in 2016.

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

The Condensed Consolidating Statements of Operations and Comprehensive Income (Loss) for the three and six months ended June 30, 2016 and 2015, Condensed Consolidating Balance Sheets as of June 30, 2016 and December 31, 2015, and Condensed Consolidating Statements of Cash Flows for the six months ended June 30, 2016 and 2015, for FES (parent and guarantor), FG and NG (non-guarantor) are presented below. These statements are provided as FES fully and unconditionally guarantees outstanding registered securities of FG as well as FG's obligations under the facility lease for the Bruce Mansfield sale and leaseback that underlie outstanding registered pass-through trust certificates. Investments in wholly owned subsidiaries are accounted for by FES using the equity method. Results of operations for FG and NG are, therefore, reflected in FES’ investment accounts and earnings as if operating lease treatment was achieved. The principal elimination entries eliminate investments in subsidiaries and intercompany balances and transactions and the entries required to reflect operating lease treatment associated with the 2007 Bruce Mansfield Unit 1 sale and leaseback transaction.

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

For the Three Months Ended June 30, 2016	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF OPERATIONS					
REVENUES	$1,061	$400	$473	$ (832)	$ 1,102
OPERATING EXPENSES:					
Fuel	—	181	47	—	228
Purchased power from affiliates	950	—	49	(832)	167
Purchased power from non-affiliates	266	—	—	—	266
Other operating expenses	119	88	148	14	369
Provision for depreciation	3	32	50	(1)	84
General taxes	7	6	6	—	19
Impairment of assets	23	517	—	—	540
Total operating expenses	1,368	824	300	(819)	1,673
OPERATING INCOME (LOSS)	(307)	(424)	173	(13)	(571)
OTHER INCOME (EXPENSE):					
Investment income, including net income (loss) from equity investees	(163)	7	22	153	19
Miscellaneous income	1	—	—	—	1
Interest expense — affiliates	(12)	(2)	—	13	(1)
Interest expense — other	(13)	(26)	(13)	15	(37)
Capitalized interest	—	2	6	—	8
Total other income (expense)	(187)	(19)	15	181	(10)
INCOME (LOSS) BEFORE INCOME TAXES (BENEFITS)	(494)	(443)	188	168	(581)
INCOME TAXES (BENEFITS)	(56)	(149)	61	1	(143)
NET INCOME (LOSS)	$(438)	$(294)	$127	$ 167	$ (438)
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)					
NET INCOME (LOSS)	$(438)	$(294)	$127	$ 167	$ (438)
OTHER COMPREHENSIVE INCOME (LOSS):					
Pension and OPEB prior service costs	(3)	(4)	—	4	(3)
Amortized gains on derivative hedges	(1)	—	—	—	(1)
Change in unrealized gains on available-for-sale securities	33	—	32	(32)	33
Other comprehensive income (loss)	29	(4)	32	(28)	29
Income taxes (benefits) on other comprehensive income (loss)	12	(2)	13	(11)	12
Other comprehensive income (loss), net of tax	17	(2)	19	(17)	17

COMPREHENSIVE INCOME (LOSS)	$(421)	$(296)	$146	$ 150	$ (421)

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

For the Six Months Ended June 30, 2016	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF OPERATIONS					
REVENUES	$2,216	$815	$1,004	$ (1,734)	$ 2,301
OPERATING EXPENSES:					
Fuel	—	300	93	—	393
Purchased power from affiliates	1,877	—	106	(1,734)	249
Purchased power from non-affiliates	643	—	—	—	643
Other operating expenses	123	159	301	26	609
Provision for depreciation	6	63	100	(2)	167
General taxes	15	16	14	—	45
Impairment of assets	23	517	—	—	540
Total operating expenses	2,687	1,055	614	(1,710)	2,646
OPERATING INCOME (LOSS)	(471)	(240)	390	(24)	(345)
OTHER INCOME (EXPENSE):					
Investment income, including net income (loss) from equity investees	86	13	39	(106)	32
Miscellaneous income	3	—	—	—	3
Interest expense — affiliates	(21)	(4)	(2)	24	(3)
Interest expense — other	(26)	(52)	(24)	29	(73)
Capitalized interest	—	4	14	—	18
Total other income (expense)	42	(39)	27	(53)	(23)
INCOME (LOSS) BEFORE INCOME TAXES (BENEFITS)	(429)	(279)	417	(77)	(368)
INCOME TAXES (BENEFITS)	(122)	(88)	147	2	(61)
NET INCOME (LOSS)	$(307)	$(191)	$270	$ (79)	$ (307)
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)					
NET INCOME (LOSS)	$(307)	$(191)	$270	$ (79)	$ (307)
OTHER COMPREHENSIVE INCOME (LOSS):					
Pensions and OPEB prior service costs	(7)	(7)	—	7	(7)
Amortized gains on derivative hedges	(1)	—	—	—	(1)
Change in unrealized gains on available-for-sale securities	56	—	55	(55)	56
Other comprehensive income (loss)	48	(7)	55	(48)	48
Income taxes (benefits) on other comprehensive income (loss)	19	(3)	21	(18)	19
Other comprehensive income (loss), net of tax	29	(4)	34	(30)	29

COMPREHENSIVE INCOME (LOSS)	$(278)	$(195)	$304	$ (109)	$ (278)

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

For the Three Months Ended June 30, 2015	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF OPERATIONS					
REVENUES	$1,074	$346	$456	$ (757)	$ 1,119
OPERATING EXPENSES:					
Fuel	—	150	41	—	191
Purchased power from affiliates	768	—	66	(757)	77
Purchased power from non-affiliates	392	—	—	—	392
Other operating expenses	86	75	164	12	337
Provision for depreciation	2	32	47	—	81
General taxes	11	7	7	—	25
Impairment of assets	16	—	—	—	16
Total operating expenses	1,275	264	325	(745)	1,119
OPERATING INCOME (LOSS)	(201)	82	131	(12)	—
OTHER INCOME (EXPENSE):					
Investment income, including net income from equity investees	119	5	3	(126)	1
Miscellaneous income	1	3	—	—	4
Interest expense — affiliates	(7)	(2)	(1)	8	(2)
Interest expense — other	(13)	(26)	(12)	14	(37)
Capitalized interest	—	2	7	—	9
Total other income (expense)	100	(18)	(3)	(104)	(25)
INCOME (LOSS) BEFORE INCOME TAXES (BENEFITS)	(101)	64	128	(116)	(25)
INCOME TAXES (BENEFITS)	(80)	28	47	1	(4)
NET INCOME (LOSS)	$(21)	$36	$81	$ (117)	$ (21)
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)					
NET INCOME (LOSS)	$(21)	$36	$81	$ (117)	$ (21)
OTHER COMPREHENSIVE INCOME (LOSS):					
Pension and OPEB prior service costs	(4)	(4)	—	4	(4)
Amortized gains on derivative hedges	(1)	—	—	—	(1)
Change in unrealized gains on available for sale securities	(12)	—	(12)	12	(12)
Other comprehensive loss	(17)	(4)	(12)	16	(17)
Income tax benefits on other comprehensive loss	(6)	(2)	(4)	6	(6)
Other comprehensive loss, net of tax	(11)	(2)	(8)	10	(11)
COMPREHENSIVE INCOME (LOSS)	$(32)	$34	$73	$ (107)	$ (32)

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

For the Six Months Ended June 30, 2015	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
STATEMENTS OF OPERATIONS					
REVENUES	$2,406	$839	$963	$ (1,712)	$ 2,496
OPERATING EXPENSES:					
Fuel	—	330	91	—	421
Purchased power from affiliates	1,725	—	134	(1,712)	147
Purchased power from non-affiliates	935	—	—	—	935
Other operating expenses	266	142	318	24	750
Provision for depreciation	5	62	95	(1)	161
General taxes	26	15	13	—	54
Impairment of assets	16	—	—	—	16
Total operating expenses	2,973	549	651	(1,689)	2,484
OPERATING INCOME (LOSS)	(567)	290	312	(23)	12
OTHER INCOME (EXPENSE):					
Investment income, including net income from equity investees	360	8	17	(371)	14
Miscellaneous income	1	3	—	—	4
Interest expense — affiliates	(13)	(4)	(2)	15	(4)
Interest expense — other	(26)	(52)	(25)	29	(74)
Capitalized interest	—	3	15	—	18
Total other income (expense)	322	(42)	5	(327)	(42)
INCOME (LOSS) BEFORE INCOME TAXES (BENEFITS)	(245)	248	317	(350)	(30)
INCOME TAXES (BENEFITS)	(221)	95	117	3	(6)
NET INCOME (LOSS)	$(24)	$153	$200	$ (353)	$ (24)
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)					
NET INCOME (LOSS)	$(24)	$153	$200	$ (353)	$ (24)
OTHER COMPREHENSIVE INCOME (LOSS):					
Pension and OPEB prior service costs	(8)	(8)	—	8	(8)
Amortized gains on derivative hedges	(2)	—	—	—	(2)
Change in unrealized gains on available-for-sale securities	(9)	—	(9)	9	(9)
Other comprehensive loss	(19)	(8)	(9)	17	(19)
Income tax benefits on other comprehensive loss	(7)	(3)	(3)	6	(7)
Other comprehensive loss, net of tax	(12)	(5)	(6)	11	(12)
COMPREHENSIVE INCOME (LOSS)	$(36)	$148	$194	$ (342)	$ (36)

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FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING BALANCE SHEETS

As of June 30, 2016	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$—	$2	$—	$ —	$ 2
Receivables-					
Customers	225	—	—	—	225
Affiliated companies	333	323	286	(531)	411
Other	28	2	7	—	37
Notes receivable from affiliated companies	385	1,467	768	(2,620)	—
Materials and supplies	48	165	217	—	430
Derivatives	155	—	—	—	155
Collateral	20	—	—	—	20
Prepayments and other	64	17	—	—	81
	1,258	1,976	1,278	(3,151)	1,361
PROPERTY, PLANT AND EQUIPMENT:					
In service	121	5,665	8,588	(382)	13,992
Less — Accumulated provision for depreciation	46	1,900	3,955	(195)	5,706
	75	3,765	4,633	(187)	8,286
Construction work in progress	3	269	789	—	1,061
	78	4,034	5,422	(187)	9,347
INVESTMENTS:					
Nuclear plant decommissioning trusts	—	—	1,510	—	1,510
Investment in affiliated companies	7,593	—	—	(7,593)	—
Other	—	10	—	—	10
	7,593	10	1,510	(7,593)	1,520
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income tax benefits	254	127	—	(381)	—
Customer intangibles	52	—	—	—	52
Property taxes	—	6	14	—	20
Derivatives	83	—	—	—	83
Other	22	336	—	19	377
	411	469	14	(362)	532
	$9,340	$6,489	$8,224	$ (11,293)	$ 12,760
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	$—	$396	$68	$ (25)	$ 439
Short-term borrowings-					
Affiliated companies	2,344	478	8	(2,620)	210
Accounts payable-					
Affiliated companies	633	172	155	(600)	360
Other	19	95	—	—	114
Accrued taxes	11	43	50	(26)	78
Derivatives	95	4	—	—	99

Other	70	61	9	33	173
	3,172	1,249	290	(3,238)	1,473
CAPITALIZATION:					
Total equity	5,357	2,751	4,807	(7,558)	5,357
Long-term debt and other long-term obligations	692	1,924	837	(1,106)	2,347
	6,049	4,675	5,644	(8,664)	7,704
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	—	—	—	774	774
Accumulated deferred income taxes	5	—	787	(165)	627
Retirement benefits	27	317	—	—	344
Asset retirement obligations	—	188	689	—	877
Derivatives	40	6	—	—	46
Other	47	54	814	—	915
	119	565	2,290	609	3,583
	$9,340	$6,489	$8,224	$ (11,293)	$ 12,760

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

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Six Months Ended June 30, 2016	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$(336)	$308	$596	$ (12)	$ 556
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Short-term borrowings, net	322	89	8	(209)	210
Redemptions and Repayments-					
Long-term debt	—	(12)	(245)	12	(245)
Other	—	(2)	—	—	(2)
Net cash provided from (used for) financing activities	322	75	(237)	(197)	(37)
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(27)	(126)	(182)	—	(335)
Nuclear fuel	—	—	(188)	—	(188)
Sales of investment securities held in trusts	—	—	441	—	441
Purchases of investment securities held in trusts	—	—	(467)	—	(467)
Cash investments	11	—	—	—	11
Loans to affiliated companies, net	22	(257)	37	209	11
Other	8	—	—	—	8
Net cash provided from (used for) investing activities	14	(383)	(359)	209	(519)
Net change in cash and cash equivalents	—	—	—	—	—
Cash and cash equivalents at beginning of period	—	2	—	—	2
Cash and cash equivalents at end of period	$—	$2	$—	$ —	$ 2

FIRSTENERGY SOLUTIONS CORP.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Six Months Ended June 30, 2015	FES	FG	NG	Eliminations	Consolidated
	(In millions)				
NET CASH PROVIDED FROM (USED FOR) OPERATING ACTIVITIES	$(600)	$275	$680	$ (12)	$ 343
CASH FLOWS FROM FINANCING ACTIVITIES:					
New Financing-					
Short-term borrowings, net	674	62	—	(612)	124
Redemptions and Repayments-					
Long-term debt	(17)	(12)	(52)	12	(69)
Short-term borrowings, net	—	—	(28)	28	—
Other	—	(2)	—	—	(2)
Net cash provided from (used for) financing activities	657	48	(80)	(572)	53
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(2)	(95)	(167)	—	(264)
Nuclear fuel	—	—	(97)	—	(97)
Sales of investment securities held in trusts	—	—	376	—	376
Purchases of investment securities held in trusts	—	—	(404)	—	(404)
Loans to affiliated companies, net	(55)	(234)	(308)	584	(13)
Other	—	6	—	—	6
Net cash used for investing activities	(57)	(323)	(600)	584	(396)
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 includes regulated electric generation facilities located primarily in West Virginia, Virginia and New Jersey that MP and JCP&L, respectively, own or contractually control. The segment's results reflect the commodity costs of securing electric generation and the deferral and amortization of certain fuel costs. As of June 30, 2016, this business segment controlled 3,790 MWs of generating capacity.

The Regulated Transmission segment transmits electricity through transmission facilities owned and operated by ATSI, TrAIL, and certain of FirstEnergy's utilities (JCP&L, ME, PN, MP, PE and WP). 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, subject to annual true-up. 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 June 30, 2016, this business segment controlled 13,162 MWs of 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.

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 June 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 $2.8 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)					
June 30, 2016						
External revenues	$2,200	$ 264	$ 1,008	$ (39)	$ (32)	$ 3,401
Internal revenues	—	—	108	—	(108)	—
Total revenues	2,200	264	1,116	(39)	(140)	3,401
Depreciation	170	44	103	17	—	334
Amortization of regulatory assets, net	61	2	—	—	—	63
Impairment of assets (Note 2)	—	—	1,447	—	—	1,447
Investment income	13	—	18	—	(12)	19
Interest expense	145	42	48	54	—	289
Income taxes (benefits)	84	42	(230)	(27)	1	(130)
Net income (loss)	146	71	(1,259)	(47)	—	(1,089)
Total assets	27,907	7,855	15,464	175	—	51,401
Total goodwill	5,092	526	—	—	—	5,618
Property additions	313	251	213	17	—	794
June 30, 2015						
External revenues	$2,239	$ 269	$ 1,034	$ (42)	$ (35)	$ 3,465
Internal revenues	—	—	162	—	(162)	—
Total revenues	2,239	269	1,196	(42)	(197)	3,465
Depreciation	170	38	99	15	—	322
Amortization of regulatory assets, net	57	2	—	—	—	59
Impairment of assets	—	—	16	—	—	16
Investment income (loss)	12	—	—	(5)	(10)	(3)
Interest expense	146	40	48	49	(1)	282
Income taxes (benefits)	91	52	(4)	(22)	(2)	115
Net income (loss)	156	89	(8)	(50)	—	187
Total assets	28,006	6,855	16,417	893	—	52,171
Total goodwill	5,092	526	800	—	—	6,418
Property additions	312	297	191	18	—	818
For the Six Months Ended						
June 30, 2016						
External revenues	$4,721	$ 539	$ 2,160	$ (81)	$ (69)	$ 7,270
Internal revenues	—	—	260	—	(260)	—
Total revenues	4,721	539	2,420	(81)	(329)	7,270
Depreciation	339	87	205	32	—	663
Amortization of regulatory assets, net	120	4	—	—	—	124
Impairment of assets (Note 2)	—	—	1,447	—	—	1,447
Investment income	24	—	33	11	(21)	47
Interest expense	292	85	95	105	—	577
Income taxes (benefits)	182	85	(145)	(40)	1	83

Net income (loss)	311	145	(1,115)	(102)	—	(761)
Property additions	575	509	382	26	—	1,492
June 30, 2015						
External revenues	$4,801	$ 507	$ 2,209	$ (84)	$ (71)	$ 7,362
Internal revenues	—	—	422	—	(422)	—
Total revenues	4,801	507	2,631	(84)	(493)	7,362
Depreciation	342	75	195	29	—	641
Amortization of regulatory assets, net	86	5	—	—	—	91
Impairment of assets	—	—	16	—	—	16
Investment income (loss)	25	—	12	(3)	(20)	14
Interest expense	290	79	96	96	—	561
Income taxes (benefits)	213	94	(8)	(40)	—	259
Net income (loss)	364	161	(16)	(100)	—	409
Property additions	592	551	317	26	—	1,486

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 includes regulated electric generation facilities located primarily in West Virginia, Virginia and New Jersey that MP and JCP&L, respectively, own or contractually control. The segment's results reflect the commodity costs of securing electric generation and the deferral and amortization of certain fuel costs. As of June 30, 2016, this business segment controlled 3,790 MWs of generating capacity.

The Regulated Transmission segment transmits electricity through transmission facilities owned and operated by ATSI, TrAIL, and certain of FirstEnergy's utilities (JCP&L, ME, PN, MP, PE and WP). 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, subject to annual true-up. 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 June 30, 2016, this business segment controlled 13,162 MWs of 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.

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 June 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 $2.8 billion was borrowed by FE under its revolving credit facility.

EXECUTIVE SUMMARY

While competitive markets continue to be challenged by depressed power and capacity prices, FirstEnergy is focused on capitalizing on investment opportunities available in its Regulated Transmission and Regulated Distribution businesses. FirstEnergy's regulated investment strategy focuses on delivering enhanced customer service and reliability, strengthening grid and cyber-security and adding resiliency and operating flexibility to its transmission and distribution infrastructure. Over time, FirstEnergy will work to reduce its exposure to competitive markets, and ultimately expects to operate as a fully regulated integrated utility company.

Regulated Transmission

The centerpiece of FirstEnergy's regulated investment strategy is the Energizing the Future transmission expansion plan. The initial phase of this plan includes $4.2 billion in investments from 2014 through 2017 to modernize FirstEnergy's transmission system. Through 2015, FirstEnergy's capital expenditures under this plan were $2.4 billion and in 2016 capital expenditures under this plan are projected to be approximately $1.05 billion.

Additionally, in June 2015, JCP&L, PN, ME, FET, and MAIT made filings with FERC, the NJBPU, and the PPUC requesting authorization for JCP&L, PN and ME to contribute their transmission assets to MAIT, which will operate similar to FET's two existing stand-alone transmission subsidiaries, ATSI and TrAIL. FERC approved the transaction in February 2016 and the PPUC adopted a Motion on July 21, 2016, approving the transaction, subject to the entry of a final order, which is expected in the near future. In February 2016, the NJBPU issued an Order concluding that MAIT does not satisfy the "electricity distribution" element necessary for "public utility" status and in April 2016, JCP&L and MAIT filed a supplemental petition and testimony seeking to include certain JCP&L distribution assets in the transfer to satisfy the "electricity distribution" element necessary for "public utility" status in accordance with the NJPBU's February 2016 order. Upon receipt of all applicable regulatory approvals with respect to the transfer, MAIT expects to file a Section 204 application with FERC, and other necessary filings with the PPUC and the NJBPU, seeking authorization to issue equity to FET, JCP&L, PN and ME for their respective contributions, and to issue debt. MAIT will also make a Section 205 formula rate application with FERC to establish its transmission rate.

Regulated Distribution

During the second quarter of 2016, FirstEnergy continued to pursue key regulatory initiatives across its utility footprint, focusing on providing significant benefits to customers while ensuring the timely and appropriate recovery of investments. These initiatives included:

- On February 11, 2016, the PPUC approved the Pennsylvania Companies' LTIIPs for infrastructure improvements over the 2016-2020 period totaling nearly $245 million. 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.

- The Ohio Companies' ESP IV, Powering Ohio's Progress, was approved by the PUCO on March 31, 2016, with certain modifications and included an Economic Stability Program that flows through charges or credits through Rider RRS representing the net result of the price paid to FES through an eight-year FERC-jurisdictional PPA, referred to as the ESP IV PPA, for the output of the ESP IV PPA Facilities against the revenues received from selling such output into the PJM markets. On April 1, 2016, the Ohio Companies and FES entered into the ESP IV PPA. However, on April 27, 2016, FERC issued an order prohibiting any transactions under the ESP IV PPA pending future authorization by FERC and directed FES to submit the ESP IV PPA for FERC review if the companies desired to transact under the agreement. FES did not file the ESP IV PPA for FERC review but rather agreed to suspend the ESP IV PPA prior to transacting thereunder, pending the outcome of the PUCO and FERC proceedings.

On April 29, 2016 and May 2, 2016, applications for rehearing on the Ohio Companies ESP IV were filed with the PUCO by several parties, including the Ohio Companies. As part of the Ohio Companies' application for rehearing, the Ohio Companies proposed a modified Rider RRS. The PUCO issued an Entry on Rehearing on May 11, 2016 granting the applications for rehearing for the purpose of further consideration of the matters raised therein. On June 29, 2016, PUCO Staff filed testimony recommending that the Ohio Companies' modified Rider RRS proposal be denied, and instead recommended a new Distribution Modernization Rider providing for the collection of $131 million annually for three years with a possible extension for an additional two years. The hearing began on July 11, 2016 for the modified Rider RRS proposal. On July 25, 2016, the Ohio Companies filed testimony that continues to recommend that the PUCO approve the proposed modified Rider RRS and that the revenues and expenses of the proposed modified Rider RRS be excluded from the significantly excessive earnings test. The Ohio Companies' filing also provided testimony that a properly designed Distribution Modernization Rider would be valued at $558 million annually for 8 years, include an additional amount, as determined by the PUCO, that recognizes the value of the economic impact of FirstEnergy maintaining its headquarters in Ohio, and would also be excluded from the significantly excessive earnings test.

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

- 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. JCP&L requested that the proposed new rates take effect in January 2017. On July 13, 2016, this matter was submitted to the Office of Administrative Law for hearing and the issuance of an Initial Decision. A procedural schedule has not yet been issued.

- 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 Act 40 of 2016, the Pennsylvania Companies submitted testimony on July 7, 2016, quantifying the value of the elimination of the CTA and outlined their plan for investing 50% of that amount in rate base eligible equipment as required by the new law. A procedural schedule has been set with hearings commencing on September 6, 2016. The proposed new rates are expected to take effect in January 2017, pending regulatory approval.

Competitive Energy Services

With the present forward market indicators, 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 going forward, 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 July 1, 2016 to December 31, 2016, CES' generation supply, including committed purchases, is 100% hedged against committed sales assuming normal weather conditions. Contractual sales obligations for the periods July 1, 2016 to December 31, 2016 and 2017 are approximately 31 million MWHs and 51 million MWHs, respectively.

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

During the second quarter of 2016 PJM conducted the BRA for the 2019/2020 delivery year. FirstEnergy's net competitive capacity position as a result of PJM's BRAs and Capacity Performance transition auctions is as follows:

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

	2018 - 2019*				2019 - 2020*			
	Base Generation		Capacity Performance		Base Generation		Capacity Performance	
	(MW)	($/MWD)	(MW)	($/MWD)	(MW)	($/MWD)	(MW)	($/MWD)
ATSI	—	$149.98	6,245	$164.77	—	$80.00	5,680	$100.00
RTO	240	$149.98	3,930	$164.77	245	$80.00	3,691	$100.00
All Other Zones	35	**	20	**	37	***	18	***
	275		10,195		282		9,389	

*Approximately 790 MWs, 130 MWs, 885 MWs and 667 MWs remain uncommitted for the delivery years 2016/2017, 2017/2018, 2018/2019 and 2019/2020, respectively.
**Base Generation: 10 MWs cleared at $200.21/MWD and 25 MWs cleared at $149.98/MWD. Capacity Performance: 5 MWs cleared at $215.00/MWD and 15 MWs cleared at $164.77/MWD.
***Base Generation: 13 MWs cleared at $182.77/MWD and 24 MWs cleared at $80.00/MWD. Capacity Performance: 5 MWs cleared at $100.00/MWD and 13 MWs cleared at $202.77/MWD.

Projected Capacity Revenue* (In millions)

	2016	2017	2018	2019	2020 (through 5/31)
CES	$815	$590	$620	$465	$147
FES	$695	$470	$475	$355	$115

*Includes revenues from the results of incremental/transitional capacity auctions, bilateral transactions and capacity transfer rights.

Current market dynamics continue to challenge FirstEnergy's competitive generation fleet, including FES, and CES continues to evaluate its overall generation business, including plant operations, capital investments, and operation and maintenance expenses, in light of the continued pressure on energy and capacity prices.

On July 22, 2016, FirstEnergy announced its intent to exit the Bay Shore Unit 1 generating station (136 MW) by October 1, 2020 either through sale or deactivation, and to deactivate Units 1-4 of the W. H. Sammis generating station (720 MW) by May 31, 2020. These decisions resulted in impairment charges to write-off assets of $150 million and $497 million, respectively, in the second quarter of 2016. While FirstEnergy and FES made the decision to sell or deactivate the unit at Bay Shore and deactivate Sammis Units 1-4, deactivation is subject to review by PJM.

Additionally, as a result of low capacity prices associated with the 2019/2020 PJM Base Residual Auction as well as an update to CES’ fundamental long-term capacity and energy price forecast, FE recognized a goodwill impairment charge of $800 million, representing the total amount of goodwill at CES as well as valuation allowances against state and local NOL carryforwards of $159 million that management believes, more likely than not, will not be realized based primarily on projected taxable income reflecting CES’ updated fundamental long-term pricing model and certain statutory limitations on the utilization of state and local NOL carryforwards.

FirstEnergy believes that a combination of distribution, transmission and generation assets in a regulated model is the best way to serve customers, and continues to evaluate alternative options that would de-risk the competitive generation fleet and convert MWs from competitive markets to a regulated or regulated-like construct. In particular, FirstEnergy will monitor legislative efforts aimed at maintaining important baseload generation in various states, including Ohio and New York. FirstEnergy also plans to work with the WVPSC as they address the generation shortfall included in Mon Power’s IRP.

At the same time, FirstEnergy will continue to advocate for reforms that ensure competitive wholesale markets adequately value baseload generation, which is essential to maintaining grid reliability. If these options are not possible, are only possible for a portion of the CES fleet or market conditions continue to be depressed, FirstEnergy may consider other options, including the sale or deactivation of generating plants. No assurance can be given, however, that any such options will be realized.

CES, including FES, will continue to review the economics of all generating units on an ongoing basis, and is expected to be cash flow positive 2016 through 2018 each year, with the ability to reinvest in its own business and cover currently anticipated capital expenditures during that time. FirstEnergy does not intend to infuse additional equity into CES, including FES, in order to support that segment’s credit ratings. CES identified additional fuel savings for 2017 and 2018 of $80 million each year, beyond those announced as part of the CFIP initiative. Furthermore, CES, including FES, delayed its Beaver Valley Unit 2 steam generator replacement project from 2020 to 2023. CES, including FES, will continue to invest in its nuclear units in order to maintain safe and reliable operations in accordance with nuclear industry standards. Market conditions will continue to impact capital investments in the fossil fleet, with current conditions favoring limited investments.

Competitive markets continue to challenge coal and nuclear baseload generation within FirstEnergy’s footprint. Because CES, including FES, is subject to wholesale market prices and capacity auction prices, which continue to be depressed, FirstEnergy and CES', including FES', future results of operations and financial condition could be negatively and materially impacted.

FINANCIAL OVERVIEW

(In millions, except per share amounts)	For the Three Months Ended June 30				For the Six Months Ended June 30			
	2016	2015	Change		2016	2015	Change	
REVENUES:	$3,401	$3,465	$(64)	(2)%	$7,270	$7,362	$(92)	(1)%
OPERATING EXPENSES:								
Fuel	438	383	55	14 %	819	896	(77)	(9)%
Purchased power	889	989	(100)	(10)%	2,013	2,102	(89)	(4)%
Other operating expenses	964	900	64	7 %	1,882	1,957	(75)	(4)%
Provision for depreciation	334	322	12	4 %	663	641	22	3 %
Amortization of regulatory assets, net	63	59	4	7 %	124	91	33	36 %
General taxes	241	242	(1)	— %	521	511	10	2 %
Impairment of assets	1,447	16	1,431	NM	1,447	16	1,431	NM
Total operating expenses	4,376	2,911	1,465	50 %	7,469	6,214	1,255	20 %
OPERATING INCOME (LOSS)	(975)	554	(1,529)	NM	(199)	1,148	(1,347)	NM
OTHER INCOME (EXPENSE):								
Investment income (loss)	19	(3)	22	NM	47	14	33	NM
Interest expense	(289)	(282)	(7)	2 %	(577)	(561)	(16)	3 %
Capitalized financing costs	26	33	(7)	(21)%	51	67	(16)	(24)%
Total other expense	(244)	(252)	8	(3)%	(479)	(480)	1	— %
INCOME (LOSS) BEFORE INCOME TAXES (BENEFITS)	(1,219)	302	(1,521)	NM	(678)	668	(1,346)	NM
INCOME TAXES (BENEFITS)	(130)	115	(245)	NM	83	259	(176)	(68)%
NET INCOME (LOSS)	$(1,089)	$187	$(1,276)	NM	$(761)	$409	$(1,170)	NM
EARNINGS (LOSSES) PER SHARE OF COMMON STOCK:								
Basic	$(2.56)	$0.44	$(3.00)	NM	$(1.79)	$0.97	$(2.76)	NM
Diluted	$(2.56)	$0.44	$(3.00)	NM	$(1.79)	$0.97	$(2.76)	NM

NM - Not Meaningful

For the Three Months Ended June 30, 2016

FirstEnergy’s net loss in the second quarter of 2016 was $(1,089) million, or a basic and diluted loss of $(2.56) per share of common stock, compared with net income of $187 million, or basic and diluted earnings of $0.44 per share of common stock in the second quarter of 2015.

As further discussed below, FirstEnergy’s second quarter 2016 operating results decreased $1,276 million as compared to the second quarter of 2015, primarily resulting from asset impairment and plant exit costs consisting of:

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

During the second quarter of 2016, FirstEnergy’s revenues decreased $64 million as compared to the same period in 2015, resulting from an $80 million decrease at CES, a $39 million decrease at Regulated Distribution, and a $5 million decrease at Regulated Transmission.

- The decrease in revenue at CES resulted from a 4 million MWHs 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 and increased capacity revenue associated with higher capacity auction prices.
- The decrease in revenue at Regulated Distribution resulted from lower regulated generation sales volumes due to increased customer shopping as well as lower industrial usage in West Virginia. The declines in regulated generation sales volumes were partially offset by the impact of rate increases at the Pennsylvania companies implemented in May of 2015 as a result of approved rate cases.
- The decrease in revenue at Regulated Transmission primarily reflected 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, partially offset by higher recovery of incremental operating expenses and a higher asset base at ATSI and TrAIL.

Operating expenses increased $1,465 million in the second quarter of 2016 as compared to the second quarter of 2015, reflecting an increase at CES of $1,414 million and Regulated Transmission of $17 million, partially offset by a decrease at Regulated Distribution of $22 million. Changes in certain operating expenses include the following:

- Fuel expense increased $55 million primarily resulting from settlement and termination costs on coal contracts recognized in the second quarter of 2016 at CES as well as higher generation at CES' and Regulated Distribution.
- Purchased power decreased $100 million due to lower required volumes at Regulated Distribution as a result of higher customer shopping as well as lower volumes at CES associated with lower contract sales.
- Other operating expenses increased $64 million, primarily reflecting an increase of $42 million at Regulated Distribution associated with higher transmission expenses and retirement benefit costs and an increase at CES due to mark-to-market losses on commodity contract positions.
- Impairment of assets increased $1,431 million due to impairment charges at CES associated with goodwill ($800 million) and the announcement to exit operations of Units 1-4 of the W. H. Sammis generating station ($497 million) and the Bay Shore Unit 1 generating station ($150 million).

FirstEnergy’s effective tax rate was 10.7% for the three months ended June 30, 2016 compared to 38.1% for the same period in 2015. The change in the effective tax rate resulted from an $800 million goodwill impairment, of which $433 million is non-deductible for tax purposes, as well as valuation allowances recorded in the second quarter of 2016 relating to 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 fundamental long-term pricing model for energy and capacity in the second quarter of 2016 as well as certain statutory limitations on the utilization of state and local NOL carryforwards.

For the Six Months Ended June 30, 2016

For the six months ended June 30, 2016, FirstEnergy's net loss was $(761) million, or a basic and diluted loss of $(1.79) per share of common stock, compared to net income of $409 million, or basic and diluted earnings of $0.97 per share of common stock for the six months ended June 30, 2015.

FirstEnergy's 2016 year-to-date earnings decreased $1,170 million as compared to the same period of 2015 primarily reflecting asset impairment and plant exit costs discussed above.

During the first six months of 2016, FirstEnergy’s revenues decreased $92 million as compared to the same period in 2015, resulting from a $211 million decrease at CES and a $80 million decrease at Regulated Distribution, partially offset by an increase of $32 million at Regulated Transmission.

- The decrease in revenue at CES resulted from an 11 million MWHs 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 and increased capacity revenue associated with higher capacity auction prices.
- The decrease in revenue at Regulated Distribution resulted from lower distribution deliveries to residential and commercial customers resulting from decreased weather-related usage and lower average customer usage associated with more energy efficient products and services as well as lower deliveries to industrial customers. Regulated generation sales volumes were also lower year-over-year due to increased customer shopping and lower industrial usage in West Virginia. These declines were partially offset by the impact of net rate increases implemented in the first six months of 2015 as a result of approved rate cases at certain operating companies.
- The increase in revenue at Regulated Transmission primarily reflected higher 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 $1,255 million during the first six months of 2016 as compared to 2015, reflecting an increase at CES of $1,047 million and Regulated Transmission of $40 million. Changes in certain operating expenses include the following:

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- Fuel expense decreased $77 million resulting from lower generation at CES associated with outages and economic dispatch of fossil units.
- Purchased power decreased $89 million due to lower volumes.
- Other operating expenses decreased $75 million, reflecting a decrease of $177 million at CES resulting from lower transmission expenses and higher mark-to-market gains on commodity contract positions, partially offset by an increase of $93 million at Regulated Distribution 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 Company's ESP IV as well as higher retirement costs.
- Impairment of assets increased $1,431 million as further described above.

FirstEnergy's effective tax rate was (12.2)% for the six months ended June 30, 2016 compared to 38.8% for the same period in 2015. The decline in the effective tax rate resulted from the $800 million goodwill impairment, of which $433 million is non-deductible for tax purposes, as well as valuation allowances against state and local NOL carryforwards recorded in the second quarter of 2016 as further described above.

2016 Full Year Outlook

For 2016, FirstEnergy's financial results will be significantly impacted by asset impairment and plant exit costs at its competitive business primarily associated with the impairment of goodwill, the impairment of Bay Shore Unit 1 and W. H. Sammis Units 1-4, and other costs associated with the deactivation of certain power plants as well as valuation allowances against state and local NOL carryforwards, all of which were recognized in the second quarter of 2016 and are discussed above. The below represents a summary of the key assumptions and drivers that management expects will impact full year 2016 results of operations, by segment. However, no assurances can be made that such assumptions and drivers will materialize and actual results may vary. See the "Forward-Looking Statements" section above.

Regulated Transmission

- Increased transmission revenue associated with increased investments at ATSI and TrAIL, partially offset by a lower ROE at ATSI. The lower ROE at ATSI is the result of its FERC-approved comprehensive settlement related to the implementation of its forward-looking rate. The ROE at ATSI for 2016 is 10.38% and compares to 12.38% for the period January 1, 2015 to June 30, 2015 and 11.06% from July 1, 2015 to December 31, 2015.
- As part of FirstEnergy's Energizing the Future transmission expansion plan, 2016 forecasted capital expenditures are $1.05 billion of which approximately $715 million will be within ATSI and TrAIL and subject to their forward-looking rates with the remaining capital expenditures of $335 million to be within the Utilities' transmission system.

Regulated Distribution

- Distribution deliveries of 146.4 million MWH in 2016 (assumes normal weather) versus 148.4 million MWH in 2015, resulting from lower weather-related usage and declining average customer usage associated with more energy efficient products and services.
- Increased revenues from the full year impact of approved distribution rate increases for the Pennsylvania Companies (effective May 3, 2015) and higher DCR revenues at the Ohio Companies in connection with their ESP IV, partially offset by the full year impact of an approved distribution rate decrease at JCP&L (effective April 1, 2015).
- Lower operation and maintenance expenses as the business continues its focus on cost management.
- Increased depreciation and property taxes as a result of a higher asset base.
- Increased Pension/OPEB expense primarily due to lower amortization of prior service credits and higher pension financing costs.
- Increased regulatory charges primarily reflecting the Ohio Companies' recognition of economic development and energy efficiency obligations in accordance with the PUCO's March 31 Opinion and Order adopting and approving, with modifications, their ESP IV.
- Capital expenditures for 2016 are forecasted to be approximately $1.3 billion primarily associated with reliability improvements.

Competitive Energy Services

- Lower CES capacity revenue resulting from lower capacity rates as discussed above.
- Decreased operation and maintenance expenses primarily resulting from two nuclear refueling outages in 2016 versus three in 2015 and lower retail related costs.
- Increased Pension/OPEB expense primarily due to lower amortization of prior service credits and higher pension financing costs.
-

- Asset impairment and plant exit costs as a result of an impairment of goodwill ($800 million pre-tax), the impairment of Bay Shore Unit 1 and W. H. Sammis Units 1-4 generating stations ($647 million pre-tax), and other costs associated with the deactivation of certain power plants.
- Lower tax benefits on forecasted pre-tax losses associated with valuation allowances against state and local NOL carryforwards of $159 million and the impact of the impairment of goodwill of which $433 million was non-deductible for tax purposes.
- Capital expenditures for 2016 are forecasted to be $545 million.

Corporate / Other

- Higher net financing costs primarily due to higher interest expense.
- Reduced tax benefits on uncertain tax positions.
- Capital expenditures for 2016 are forecasted to be $85 million.

Additionally, in 2015, the Regulated Distribution and CES segments recognized pre-tax pension and OPEB mark-to-market charges associated with changes in the fair value of plan assets and net actuarial gains and losses of $179 million and $60 million, respectively. At this time, FirstEnergy is unable to determine or project the mark-to-market adjustment that may be recorded as of December 31, 2016.

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 — Second Quarter 2016 Compared with Second Quarter 2015

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

Second Quarter 2016 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$2,147	$ 264	$ 963	$ (43)	$ 3,331
Other	53	—	45	(28)	70
Internal	—	—	108	(108)	—
Total Revenues	2,200	264	1,116	(179)	3,401
Operating Expenses:					
Fuel	141	—	297	—	438
Purchased power	721	—	276	(108)	889
Other operating expenses	580	36	432	(84)	964
Provision for depreciation	170	44	103	17	334
Amortization of regulatory assets, net	61	2	—	—	63
General taxes	170	36	29	6	241
Impairment of assets	—	—	1,447	—	1,447
Total Operating Expenses	1,843	118	2,584	(169)	4,376
Operating Income (Loss)	357	146	(1,468)	(10)	(975)
Other Income (Expense):					
Investment income	13	—	18	(12)	19
Interest expense	(145)	(42)	(48)	(54)	(289)
Capitalized financing costs	5	9	9	3	26
Total Other Expense	(127)	(33)	(21)	(63)	(244)
Income (Loss) Before Income Taxes (Benefits)	230	113	(1,489)	(73)	(1,219)
Income taxes (benefits)	84	42	(230)	(26)	(130)
Net Income (Loss)	$146	$ 71	$ (1,259)	$ (47)	$ (1,089)

Second Quarter 2015 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$2,189	$ 269	$ 980	$ (43)	$ 3,395
Other	50	—	54	(34)	70
Internal	—	—	162	(162)	—
Total Revenues	2,239	269	1,196	(239)	3,465
Operating Expenses:					
Fuel	120	—	263	—	383
Purchased power	806	—	345	(162)	989
Other operating expenses	538	35	411	(84)	900
Provision for depreciation	170	38	99	15	322
Amortization of regulatory assets, net	57	2	—	—	59
General taxes	174	26	36	6	242
Impairment of assets	—	—	16	—	16
Total Operating Expenses	1,865	101	1,170	(225)	2,911
Operating Income	374	168	26	(14)	554
Other Income (Expense):					
Investment income	12	—	—	(15)	(3)
Interest expense	(146)	(40)	(48)	(48)	(282)
Capitalized financing costs	7	13	10	3	33
Total Other Expense	(127)	(27)	(38)	(60)	(252)
Income (Loss) Before Income Taxes (Benefits)	247	141	(12)	(74)	302
Income taxes (benefits)	91	52	(4)	(24)	115
Net Income (Loss)	$156	$ 89	$ (8)	$ (50)	$ 187

Changes Between Second Quarter 2016 and Second Quarter 2015 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$(42)	$ (5)	$ (17)	$ —	$ (64)
Other	3	—	(9)	6	—
Internal	—	—	(54)	54	—
Total Revenues	(39)	(5)	(80)	60	(64)
Operating Expenses:					
Fuel	21	—	34	—	55
Purchased power	(85)	—	(69)	54	(100)
Other operating expenses	42	1	21	—	64
Provision for depreciation	—	6	4	2	12
Amortization of regulatory assets, net	4	—	—	—	4
General taxes	(4)	10	(7)	—	(1)
Impairment of assets	—	—	1,431	—	1,431
Total Operating Expenses	(22)	17	1,414	56	1,465
Operating Income (Loss)	(17)	(22)	(1,494)	4	(1,529)
Other Income (Expense):					
Investment income	1	—	18	3	22
Interest expense	1	(2)	—	(6)	(7)
Capitalized financing costs	(2)	(4)	(1)	—	(7)
Total Other Expense	—	(6)	17	(3)	8
Income (Loss) Before Income Taxes (Benefits)	(17)	(28)	(1,477)	1	(1,521)
Income taxes (benefits)	(7)	(10)	(226)	(2)	(245)
Net Income (Loss)	$(10)	$ (18)	$ (1,251)	$ 3	$ (1,276)

Regulated Distribution — Second Quarter 2016 Compared with Second Quarter 2015

Regulated Distribution's net income decreased $10 million in the second quarter of 2016 as compared to the same period of 2015, reflecting increasing retirement benefit costs and lower distribution deliveries associated with a decline in average customer usage. Partially offsetting the decrease were rate increases implemented in May of 2015 as a result of approved rate cases at the Pennsylvania operating companies.

Revenues —

The $39 million decrease in total revenues resulted from the following sources:

Revenues by Type of Service	For the Three Months Ended June 30 2016	2015	Increase (Decrease)
	(In millions)		
Distribution services	$1,105	$1,089	$ 16
Generation sales:			
Retail	922	970	(48)
Wholesale	120	130	(10)
Total generation sales	1,042	1,100	(58)
Other	53	50	3
Total Revenues	$2,200	$2,239	$ (39)

Distribution services revenues increased $16 million primarily resulting from an increase associated with approved base distribution rate increases in Pennsylvania, effective May 2015, partially offset by a decline in MWH deliveries, 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 Three Months Ended June 30 2016	2015	(Decrease)
	(In thousands)		
Residential	11,656	11,839	(1.5)%
Commercial	10,349	10,411	(0.6)%
Industrial	12,346	12,688	(2.7)%
Other	145	145	— %
Total Electric Distribution MWH Deliveries	34,496	35,083	(1.7)%

Lower distribution deliveries to residential and commercial customers primarily reflect declining average customer usage associated with more energy efficient products and services. Weather-related usage was flat as decreased usage resulting from cooling degree days that were 13% below 2015, and 11% above normal, was offset by heating degree days that were 32% above 2015, and 8% above normal. Deliveries to industrial customers continue to decline 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 $58 million decrease in generation revenues for the second quarter 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	$ (61)
Change in prices	13
	(48)
Wholesale:	
Effect of increase in sales volumes	17
Change in prices	(27)
	(10)
Decrease in Generation Revenues	$ (58)

The decrease in retail generation sales volumes was primarily due to increased customer shopping in Ohio, Pennsylvania, and New Jersey as well as lower 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 69% from 67% for the Pennsylvania Companies, and to 54% from 52% for JCP&L. The increase in retail generation prices primarily resulted from an ENEC rate increase in West Virginia, effective January 1, 2016.

The decrease in wholesale generation revenues of $10 million in the second quarter of 2016, as compared to the same period in 2015, reflects 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.

Operating Expenses —

Total operating expenses decreased $22 million primarily due to the following:

- Fuel expense increased $21 million in the second quarter of 2016, as compared to the same period in 2015, primarily related to higher generation.

- Purchased power costs were $85 million lower in the second quarter of 2016, as compared to the same period in 2015, primarily due to decreased volumes reflecting increased customer shopping, as described above.

Source of Change in Purchased Power	Increase(Decrease)
	(In millions)
Purchases from non-affiliates:	
Change due to increased unit costs	$ 11
Change due to decreased volumes	(29)
	(18)
Purchases from affiliates:	
Change due to increased unit costs	4
Change due to decreased volumes	(59)
	(55)
Capacity Expense	(3)
Amortization of deferred costs	(9)

Decrease in Purchased Power Costs	$	(85)

- Other operating expenses increased $42 million primarily due to:
- Higher transmission expenses of $22 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 increased $4 million primarily due to recovery of storm costs in Pennsylvania and vegetation management program costs in West Virginia, partially offset by higher deferral of Ohio network transmission expenses.

Income Taxes —

Regulated Distribution’s effective tax rate was 36.5% and 36.8% for the quarter ended June 30, 2016 and 2015, respectively.

Regulated Transmission — Second Quarter 2016 Compared with Second Quarter 2015

Net income decreased $18 million in the second quarter of 2016 compared to the same period of 2015 reflecting lower transmission revenues, as described below, and increased net financing costs.

Revenues —

Total revenues decreased $5 million principally due to 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, partially offset by higher recovery of incremental operating expenses and a higher rate base at ATSI and TrAIL.

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

	For the Three Months Ended June 30		
Revenues by Transmission Asset Owner	2016	2015	Increase (Decrease)
	(In millions)		
ATSI	$128	$127	$ 1
TrAIL	59	65	(6)
PATH	3	3	—
Utilities	74	74	—
Total Revenues	$264	$269	$ (5)

Operating Expenses —

Total operating expenses increased $17 million principally due to higher property taxes and depreciation expense at ATSI, which are recovered through ATSI's formula rate.

Other Expense —

Total other expense increased $6 million in the second quarter of 2016 as compared to the same period of 2015 primarily due to lower capitalized financing costs of $4 million 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 37.2% and 36.9% for the quarter ended June 30, 2016 and 2015, respectively.

CES — Second Quarter 2016 Compared with Second Quarter 2015

Operating results decreased $1,251 million in the second quarter of 2016, compared to the same period of 2015, primarily resulting from charges associated with the impairments of goodwill, Units 1-4 of the W. H. Sammis generating station and the Bay Shore Unit 1 generating station as discussed above, higher net mark-to-market losses on commodity contract positions and termination and settlement costs on coal contracts, as discussed below. Operating results were also impacted by higher capacity revenues from higher capacity auction prices, lower unit prices for fuel and lower purchased power, partially offset by lower sales volumes.

Revenues —

Total revenues decreased $80 million in the second quarter of 2016, compared to the same period of 2015, primarily due to lower sales volumes resulting from the continuation of CES' strategy to more effectively hedge its generation. Revenues were also impacted by higher capacity revenues and higher 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 June 30 2016	2015	Increase (Decrease)
	(In millions)		
Contract Sales:			
Direct	$196	$324	$ (128)
Governmental Aggregation	191	218	(27)
Mass Market	37	61	(24)
POLR	125	169	(44)
Structured Sales	115	126	(11)
Total Contract Sales	664	898	(234)
Wholesale	389	216	173
Transmission	18	28	(10)
Other	45	54	(9)
Total Revenues	$1,116	$1,196	$ (80)

MWH Sales by Channel	For the Three Months Ended June 30 2016	2015	Increase (Decrease)
	(In thousands)		
Contract Sales:			
Direct	3,684	6,070	(39.3)%
Governmental Aggregation	2,991	3,453	(13.4)%
Mass Market	536	905	(40.8)%
POLR	2,081	2,920	(28.7)%
Structured Sales	2,842	2,808	1.2 %
Total Contract Sales	12,134	16,156	(24.9)%
Wholesale	3,577	804	NM
Total MWH Sales	15,711	16,960	(7.4)%

NM - Not Meaningful

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

	Source of Change in Revenues Increase (Decrease)				
MWH Sales Channel:	Sales Volumes	Prices	Gain on Settled Contracts	Capacity Revenue	Total
	(In millions)				
Direct	$(127)	$(1)	$—	$—	$(128)
Governmental Aggregation	(29)	2	—	—	(27)
Mass Market	(25)	1	—	—	(24)
POLR	(48)	4	—	—	(44)
Structured Sales	2	(13)	—	—	(11)
Wholesale	88	(24)	51	58	173

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 1.5 million as of June 30, 2016, compared to 1.9 million as of June 30, 2015.

The decrease in POLR sales of $44 million was due to lower volumes, partially offset by higher rates associated with recent POLR auctions. Structured Sales decreased $11 million primarily due to the impact of lower market prices, partially offset by higher structured transaction volumes.

Wholesale revenues increased $173 million, primarily due to an increase in capacity revenue from higher capacity auction prices, gains on financially settled contracts and an increase in short-term (net hourly position) transactions, 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 $10 million primarily due to lower congestion.

Other revenue decreased $9 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 $1,414 million in the second quarter of 2016 due to the following:

- Fuel costs increased $34 million, primarily due to a pre-tax charge of $58 million from settlement and termination costs on coal contracts recognized in the second quarter of 2016 and higher nuclear generation, partially offset by 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 $69 million due to lower volumes ($76 million) and lower capacity expense ($19 million), partially offset by higher losses on financially settled contracts ($13 million) and higher unit prices ($13 million). Lower volumes and capacity expense primarily resulted from lower contract sales as discussed above, partially offset by economic purchases, resulting from the low wholesale spot market price environment. Higher losses on financially settled contracts were due to lower wholesale spot market prices in the second quarter of 2016

compared to the second quarter of 2015. Higher unit prices were primarily due to a higher proportion of purchases coming from purchased power agreements for wind, solar and CES' entitlement in OVEC, partially offset by the lower wholesale spot prices.

- Fossil operating costs increased $13 million, primarily due to increased outage costs.
- Nuclear operating costs decreased $22 million, primarily due to lower refueling outage costs. There was one refueling outage during the second quarter of 2016, as compared to two refueling outages during the same period of 2015.
- Retirement benefit costs increased $8 million.
- Transmission expenses decreased $32 million, due to lower congestion and market-based ancillary costs, primarily resulting from lower sales.

- Other operating expenses increased $54 million, primarily due to a $79 million increase in mark-to-market losses on commodity contract positions, partially offset by lower lease expense as a result of the expiration of a nuclear sale-leaseback agreement and lower retail-related costs.

- General taxes decreased $7 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, resulting in an impairment of $647 million.

Other Expense —

Total other expense decreased $17 million in the second 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 15.4% and 33.3% for the second quarter 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 further described above as well as the impairment of goodwill, of which, $433 million is non-deductible for tax purposes.

Corporate / Other — Second Quarter 2016 Compared with Second 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 nominal $3 million increase in earnings in the second quarter of 2016, compared to the same period of 2015.

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

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

First Six Months 2016 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$4,589	$ 539	$ 2,064	$ (89)	$ 7,103
Other	132	—	96	(61)	167
Internal	—	—	260	(260)	—
Total Revenues	4,721	539	2,420	(410)	7,270
Operating Expenses:					
Fuel	280	—	539	—	819
Purchased power	1,647	—	626	(260)	2,013
Other operating expenses	1,228	72	753	(171)	1,882
Provision for depreciation	339	87	205	32	663
Amortization of regulatory assets, net	120	4	—	—	124
General taxes	355	77	68	21	521
Impairment of assets	—	—	1,447	—	1,447
Total Operating Expenses	3,969	240	3,638	(378)	7,469
Operating Income (Loss)	752	299	(1,218)	(32)	(199)
Other Income (Expense):					
Investment income	24	—	33	(10)	47
Interest expense	(292)	(85)	(95)	(105)	(577)
Capitalized financing costs	9	16	20	6	51
Total Other Expense	(259)	(69)	(42)	(109)	(479)
Income (Loss) Before Income Taxes (Benefits)	493	230	(1,260)	(141)	(678)
Income taxes (benefits)	182	85	(145)	(39)	83
Net Income (Loss)	$311	$ 145	$ (1,115)	$ (102)	$ (761)

First Six Months 2015 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$4,706	$ 507	$ 2,105	$ (88)	$ 7,230
Other	95	—	104	(67)	132
Internal	—	—	422	(422)	—
Total Revenues	4,801	507	2,631	(577)	7,362
Operating Expenses:					
Fuel	266	—	630	—	896
Purchased power	1,781	—	743	(422)	2,102
Other operating expenses	1,135	70	930	(178)	1,957
Provision for depreciation	342	75	195	29	641
Amortization of regulatory assets, net	86	5	—	—	91
General taxes	364	50	77	20	511
Impairment of assets	—	—	16	—	16
Total Operating Expenses	3,974	200	2,591	(551)	6,214
Operating Income	827	307	40	(26)	1,148
Other Income (Expense):					
Investment income	25	—	12	(23)	14
Interest expense	(290)	(79)	(96)	(96)	(561)
Capitalized financing costs	15	27	20	5	67
Total Other Expense	(250)	(52)	(64)	(114)	(480)
Income (Loss) Before Income Taxes (Benefits)	577	255	(24)	(140)	668
Income taxes (benefits)	213	94	(8)	(40)	259
Net Income (Loss)	$364	$ 161	$ (16)	$ (100)	$ 409

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Changes Between First Six Months 2016 and First Six Months 2015 Financial Results	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	$(117)	$ 32	$ (41)	$ (1)	$ (127)
Other	37	—	(8)	6	35
Internal	—	—	(162)	162	—
Total Revenues	(80)	32	(211)	167	(92)
Operating Expenses:					
Fuel	14	—	(91)	—	(77)
Purchased power	(134)	—	(117)	162	(89)
Other operating expenses	93	2	(177)	7	(75)
Provision for depreciation	(3)	12	10	3	22
Amortization of regulatory assets, net	34	(1)	—	—	33
General taxes	(9)	27	(9)	1	10
Impairment of assets	—	—	1,431	—	1,431
Total Operating Expenses	(5)	40	1,047	173	1,255
Operating Income (Loss)	(75)	(8)	(1,258)	(6)	(1,347)
Other Income (Expense):					
Investment income	(1)	—	21	13	33
Interest expense	(2)	(6)	1	(9)	(16)
Capitalized financing costs	(6)	(11)	—	1	(16)
Total Other Expense	(9)	(17)	22	5	1
Income (Loss) Before Income Taxes (Benefits)	(84)	(25)	(1,236)	(1)	(1,346)
Income taxes (benefits)	(31)	(9)	(137)	1	(176)
Net Income (Loss)	$(53)	$ (16)	$ (1,099)	$ (2)	$ (1,170)

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

Regulated Distribution's net income decreased $53 million in the first six months of 2016 as compared to the same period of 2015, reflecting increasing retirement benefit costs and lower distribution deliveries, primarily resulting from 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. Additionally, the Ohio Companies recognized $51 million in regulatory charges resulting from the PUCO's March 31 Opinion and Order adopting and approving, with modifications, the Ohio Companies' ESP IV.

Revenues —

The $80 million decrease in total revenues resulted from the following sources:

Revenues by Type of Service	For the Six Months Ended June 30 2016	2015	Increase (Decrease)
	(In millions)		
Distribution services	$2,290	$2,256	$ 34
Generation sales:			
Retail	2,057	2,150	(93)
Wholesale	242	300	(58)
Total generation sales	2,299	2,450	(151)
Other	132	95	37
Total Revenues	$4,721	$4,801	$ (80)

Distribution services revenues increased $34 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 weather-related usage as well as 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 Six Months Ended June 30 2016	2015	(Decrease)
	(In thousands)		
Residential	25,992	28,401	(8.5)%
Commercial	20,908	21,543	(2.9)%
Industrial	24,724	25,428	(2.8)%
Other	292	292	— %
Total Electric Distribution MWH Deliveries	71,916	75,664	(5.0)%

Lower distribution deliveries to residential and commercial customers primarily reflect decreased weather-related usage resulting from heating degree days that were 17% below 2015, and 8% below normal and cooling degree days that were 12% below 2015, and 11% above normal. Additionally, distribution deliveries to residential and commercial customers reflect declining average customer usage associated with more energy efficient products and services. Deliveries to industrial customers continue to decline as the increase from shale customer usage was more than offset by a decrease from steel and mining customer usage.

The following table summarizes the price and volume factors contributing to the $151 million decrease in generation revenues for the first six 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	$ (200)
Change in prices	107
	(93)
Wholesale:	
Effect of increase in sales volumes	31
Change in prices	(98)
Capacity Revenue	9
	(58)
Decrease in Generation Revenues	$ (151)

The decrease in retail generation sales volumes was primarily due to increased customer shopping in Ohio, Pennsylvania, and New Jersey as well as lower weather-related usage and industrial usage in West Virginia, as described above. Total generation provided by alternative suppliers as a percentage of total MWH deliveries increased to 81% from 79% for the Ohio Companies, to 67% from 64% for the Pennsylvania Companies and to 52% from 51% for JCP&L. The increase in retail generation prices primarily resulted from higher default service auction prices for the Pennsylvania Companies and an ENEC rate increase in West Virginia, effective January 1, 2016.

Wholesale generation revenues decreased $58 million in the first six 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 and higher capacity revenues. 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 decreased $5 million primarily due to the following:

- Fuel expense increased $14 million in the first six months of 2016, as compared to the same period of 2015, primarily related to higher generation.

- Purchased power costs decreased $134 million during the first six months of 2016, as compared to the same period of 2015 primarily due to decreased volumes reflecting lower weather-related usage and increased customer shopping, as described above.

Source of Change in Purchased Power	Increase (Decrease) (In millions)
Purchases from non-affiliates:	
Change due to decreased unit costs	$ (1)
Change due to volumes	8
	7

Purchases from affiliates:	
Change due to increased unit costs	16
Change due to volumes	(179)
	(163)
Capacity Expense	10
Amortization of deferred costs	12
Decrease in Purchased Power Costs	$ (134)

- Other operating expenses increased $93 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 retirement benefit costs of $25 million.
  - Higher transmission expenses of $11 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 $34 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 ($27 million), partially offset by
  - Higher deferral of Ohio network transmission expenses ($26 million).

- General taxes decreased $9 million primarily due to lower property taxes in Ohio, partially offset by higher revenue-related taxes in Pennsylvania.

Other Expense —

Other expense increased $9 million in the first six months of 2016 primarily due to lower capitalized financing costs as well as higher interest expense related to long-term debt issuances in 2015 at JCPL and WPP, the proceeds of which, in part, paid off short-term borrowings.

Income Taxes —

Regulated Distribution’s effective tax rate was 36.9% for the first six months of 2016 and 2015.

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

Net income decreased $16 million in the first six 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.

Revenues —

Total revenues increased $32 million principally due to higher 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 Six Months Ended June 30		Increase
	2016	2015	(Decrease)
	(In millions)		
ATSI	$262	$223	$ 39

TrAIL	120	126	(6)
PATH	6	7	(1)
Utilities	151	151	—
Total Revenues	$539	$507	$ 32

Operating Expenses —

Total operating expenses increased $40 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 $17 million in the first six 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 37.0% and 36.9% for the first six months of 2016 and 2015, respectively.

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

Operating results decreased $1,099 million in the first six months of 2016, compared to the same period of 2015, primarily resulting from charges associated with the 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, partially offset by net mark-to-market gains on commodity contract positions. Excluding these items, operating results were impacted by higher capacity revenues from higher capacity auction prices, lower fuel costs and lower purchased power, partially offset by lower sales volumes.

Revenues —

Total revenues decreased $211 million in the first six months of 2016, compared to the same period of 2015, primarily due to lower sales volumes resulting from the continuation of CES' strategy to more effectively hedge its generation. Revenues were also impacted 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 Six Months Ended June 30 2016	2015	Increase (Decrease)
	(In millions)		
Contract Sales:			
Direct	$403	$717	$ (314)
Governmental Aggregation	432	506	(74)
Mass Market	85	160	(75)
POLR	282	445	(163)
Structured Sales	277	259	18
Total Contract Sales	1,479	2,087	(608)
Wholesale	806	347	459
Transmission	39	93	(54)
Other	96	104	(8)
Total Revenues	$2,420	$2,631	$ (211)

MWH Sales by Channel	For the Six Months Ended June 30 2016	2015	Increase (Decrease)
	(In thousands)		
Contract Sales:			
Direct	7,478	13,319	(43.9)%
Governmental Aggregation	6,560	8,052	(18.5)%
Mass Market	1,239	2,340	(47.1)%
POLR	4,633	7,742	(40.2)%
Structured Sales	6,738	5,897	14.3 %
Total Contract Sales	26,648	37,350	(28.7)%
Wholesale	5,490	867	NM
Total MWH Sales	32,138	38,217	(15.9)%

NM - Not Meaningful

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	$(314)	$ —	$ —	$ —	$(314)
Governmental Aggregation	(94)	20	—	—	(74)
Mass Market	(76)	1	—	—	(75)
POLR	(179)	16	—	—	(163)
Structured Sales	37	(19)	—	—	18
Wholesale	149	(30)	121	219	459

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 1.5 million as of June 30, 2016, compared to 1.9 million as of June 30, 2015. Although unit pricing was higher year-over-year in the Government Aggregation and Mass Market channels, the increase was primarily attributable to higher capacity expense as discussed below, which is a component of the retail price.

The decrease in POLR sales of $163 million was due to lower volumes, partially offset by higher rates associated with recent POLR auctions. Structured Sales increased $18 million, primarily due to higher volumes, partially offset by the impact of lower market prices.

Wholesale revenues increased $459 million, primarily due to an increase in capacity revenue from higher capacity auction prices, an increase in short-term (net hourly position) transactions and 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 $54 million in the first six months of 2016, as compared to the same period of 2015, primarily due to lower congestion revenue associated with less volatile market conditions.

Other revenue decreased $8 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 $1,047 million in the first six months of 2016 due to the following:

- Fuel costs decreased $91 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 a pre-tax charge of $58 million from settlement and termination costs on coal contracts in the second quarter of 2016.
- Purchased power costs decreased $117 million due to lower volumes ($193 million) and lower unit prices ($3 million), partially offset by higher losses on financial settled contracts ($54 million) and higher capacity expenses ($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. Lower unit prices and higher losses on financially settled contracts were both due to lower wholesale spot market prices in the first six months of 2016, compared to the same period of 2015. The increase in capacity expense, which is a component of CES' retail price, was primarily the result of higher capacity rates associated with CES' retail sales obligations.

- Fossil operating costs increased $21 million, primarily due to increased outage costs.

- Nuclear operating costs decreased $33 million as a result of lower refueling outage costs. There was one refueling outage during the first six months of 2016 as compared to two refueling outages during the same period of 2015.

- Retirement benefit costs increased $16 million.

- Transmission expenses decreased $151 million, primarily due to lower congestion and market-based ancillary costs associated with less volatile market conditions as compared to the first six months of 2015, as well as lower load requirements.

- Other operating expenses decreased $30 million, primarily due to a $14 million increase in mark-to-market gains on commodity contract positions, lower lease expense as a result of the expiration of a nuclear sale-leaseback agreement and lower retail-related costs.
- Depreciation expense increased $10 million as a result of a higher asset base.
- General taxes decreased $9 million 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, resulting in an impairment of $647 million.

Other Expense —

Total other expense decreased $22 million in the first six 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 11.5% and 33.3% for the first six 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 Six Months of 2016 Compared with First Six Months of 2015

Financial results from the Corporate/Other operating segment and reconciling items resulted in a nominal $2 million decrease in net income in the first six months of 2016 compared to the same period of 2015.

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 June 30, 2016 and December 31, 2015, and the changes during the six months ended June 30, 2016:

Regulatory Assets (Liabilities) by Source	June 30, 2016	December 31, 2015	Increase (Decrease)
	(In millions)		
Regulatory transition costs	$143	$ 185	$ (42)
Customer receivables for future income taxes	424	355	69
Nuclear decommissioning and spent fuel disposal costs	(306)	(272)	(34)
Asset removal costs	(462)	(372)	(90)
Deferred transmission costs	136	115	21
Deferred generation costs	243	243	—
Deferred distribution costs	315	335	(20)
Contract valuations	179	186	(7)
Storm-related costs	375	403	(28)
Other	140	170	(30)
Net Regulatory Assets included on the Consolidated Balance Sheets	$1,187	$ 1,348	$ (161)

Regulatory assets that do not earn a current return totaled approximately $140 million and $148 million as of June 30, 2016 and December 31, 2015, respectively, primarily related to storm damage costs.

As of June 30, 2016 and December 31, 2015, FirstEnergy had approximately $114 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 may be met through the issuance of long-term debt and/or equity. FirstEnergy expects that borrowing capacity under credit facilities will continue to be available to manage working capital requirements along with continued access to long-term capital markets. FirstEnergy also expects to both issue long-term debt at certain Utilities and certain other subsidiaries to, among other things, refinance short-term and maturing debt in the ordinary course, and remarket PCRB's currently held by FG and NG, in each case, subject to market and other conditions.

Additionally, in 2016, FirstEnergy has minimum required funding obligations of $381 million to its qualified pension plan, of which$245 million has been contributed through July 2016, including $85 million at FES in July of 2016. FirstEnergy expects to make future contributions to the qualified pension plan in 2016 to satisfy its remaining 2016 funding obligations, as well as address certain of its future funding obligations, with cash, up to $500 million of equity or a combination thereof, depending on, among other things, market conditions.

Capital expenditures through June 30, 2016 as well as planned capital expenditures for 2016 by reportable segment are included below:

Reportable Segment	Capital Expenditures Accrued - First six months of 2016	Capital Expenditures Forecast 2016
	(In millions)	
Regulated Distribution	$619	$ 1,270
Regulated Transmission	514	1,050
Competitive Energy Services	314	545
Corporate/Other	42	85
Total	$1,489	$ 2,950

FirstEnergy's strategy is to focus on investments in its regulated operations. The centerpiece of this strategy is a $4.2 billion Energizing the Future investment plan that began in 2014 and will continue through 2017 to upgrade and expand FirstEnergy's transmission system. 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 $1.05 billion. In total, FirstEnergy has identified at least $15 billion in transmission investment opportunities across the 24,000 mile transmission system, making this a continuing platform for investment in the years beyond 2017.

In 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.

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

Currently Payable Long-Term Debt	(In millions)
PCRBs supported by bank LOCs[1]	$ 92
Unsecured notes	380
FMBs	395
Unsecured PCRBs[1]	325
Collateralized lease obligation bonds	8
Sinking fund requirements	89
Other notes	38
	$ 1,327

(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 $2,925 million and $1,708 million of short-term borrowings as of June 30, 2016 and December 31, 2015, respectively. FirstEnergy's and FES' available liquidity as of June 30, 2016, was as follows:

Borrower(s)	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy[1]	Revolving	March 2019	$3,500	$ 719
FES / AE Supply	Revolving	March 2019	1,500	1,499
FET[2]	Revolving	March 2019	1,000	850
		Subtotal	$6,000	$ 3,068
		Cash	—	199
		Total	$6,000	$ 3,267

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

Revolving Credit Facilities

FirstEnergy, FES/AE Supply and FET Facilities

FE and certain of its subsidiaries participate in three five-year syndicated revolving credit facilities with aggregate commitments of $6.0 billion (Facilities) expiring on March 31, 2019.

Generally, borrowings under each of the Facilities are available to each borrower separately and mature on the earlier of 364 days from the date of borrowing or the commitment termination date, as the same may be extended. Each of the Facilities contains financial covenants requiring each borrower to maintain a consolidated debt to total capitalization ratio (as defined under each of the Facilities, as amended) of no more than 65%, and 75% for FET, measured at the end of each fiscal quarter.

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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 June 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	—	1,500	—	—	(2)
AE Supply	—	1,000	—	—	(2)
FET	—	—	1,000	—	(1)
OE	500	—	—	500	(3)
CEI	500	—	—	500	(3)
TE	500	—	—	500	(3)
JCP&L	600	—	—	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 June 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 June 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 the holding company to meet their short-term working capital requirements. A similar but separate arrangement exists among FirstEnergy’s unregulated companies. FESC administers these two money pools and tracks surplus funds of FirstEnergy and the respective regulated and unregulated subsidiaries, as well as proceeds available from bank borrowings. Companies receiving a loan under the money pool agreements must repay the principal amount of the loan, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from their respective pool and is based on the average cost of funds available through the pool. The average interest rates for borrowings in the first six months of 2016 were 0.73% per annum for the regulated companies’ money pool and 1.83% per annum for the unregulated companies’ money pool.

Pollution Control Revenue Bonds

As of June 30, 2016, FirstEnergy’s currently payable long-term debt included approximately $92 million (all applicable to FES) of variable interest rate PCRBs, the bondholders of which are entitled to the benefit of irrevocable direct pay bank LOCs. The interest rates on the PCRBs are reset daily or weekly. Bondholders can tender their PCRBs for mandatory purchase prior to maturity with the purchase price payable from remarketing proceeds or, if the PCRBs are not successfully remarketed, by drawings on the irrevocable direct pay LOCs. The subsidiary obligor is required to reimburse the applicable LOC bank for any such drawings or, if the LOC bank fails to honor its LOC for any reason, must itself pay the purchase price. The LOCs for FirstEnergy's variable interest rate PCRBs outstanding as of June 30, 2016 were issued by the following bank:

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

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

Long-Term Debt Capacity

FE's and its subsidiaries' access to capital markets and costs of financing are influenced by the credit ratings of their securities. 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 June 30, 2016:

	Senior Secured		Senior Unsecured		
Issuer	S&P	Moody’s	S&P	Moody’s	Fitch
FE	—	—	BB+	Baa3	BB+
FES	BBB-	—	BBB-	Baa3	—
AE Supply	BBB-	—	BBB-	Baa3	—
AGC	—	—	BBB-	Baa3	—
ATSI	—	—	BBB-	Baa2	—
CEI	BBB+	Baa1	BBB-	Baa3	—
FET	—	—	BB+	Baa3	—
JCP&L	—	—	BBB-	Baa2	—
ME	—	—	BBB-	Baa1	—

MP	BBB+	A3	—	—	—
OE	BBB+	A2	BBB-	Baa1	—
PN	—	—	BBB-	Baa2	—
Penn	—	A2	—	—	—
PE	BBB+	A3	—	—	—
TE	BBB+	Baa1	—	—	—
TrAIL	—	—	BBB-	A3	—
WP	BBB+	A2	—	—	—

On July 22, 2016, S&P placed FES, AE Supply, and AGC on CreditWatch with negative implications, which could result in a downgrade to non-investment grade in the near-term.

Debt capacity is subject to the consolidated debt to total capitalization limits in the Facilities previously discussed. As of June 30, 2016, FE and its subsidiaries could issue additional debt of approximately $3.9 billion and remain within the limitations of the financial covenants required by the Facilities. As of June 30, 2016, FES' incremental debt capacity under its consolidated debt to total capitalization financial covenant is also $3.9 billion given FE's consolidated debt to total capitalization ratio under its Facility.

Changes in Cash Position

As of June 30, 2016, FirstEnergy had $199 million of cash and cash equivalents compared to $131 million of cash and cash equivalents as of December 31, 2015. As of June 30, 2016 and December 31, 2015, FirstEnergy had approximately $65 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 $1,460 million during the first six months of 2016 compared with $990 million provided from operating activities during the first six months of 2015. Cash flows from operations increased $470 million in the first six 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 associated with lower weather-related 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 six months of 2016, cash provided from financing activities was $375 million compared to $712 million of cash provided from financing activities during the first six months of 2015. The following table summarizes redemptions, repayments, short-term borrowings and dividends:

Securities Issued or Redeemed / Repaid	For the Six Months Ended June 30 2016	2015
	(In millions)	
New Issues		
Term Loan	$—	$200
	$—	$200
Redemptions / Repayments		
Term Loan	$—	$(200)
Unsecured notes	(356)	—
Senior secured notes	(225)	(92)

	$(581)	$(292)
Short-term borrowings, net	$1,225	$1,109
Common stock dividend payments	$(305)	$(303)

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. NG is currently holding these PCRBs for future remarketing in 2016 subject to market and other conditions as further described above.

On July 11, 2016, Penn issued $50 million of its 4.24% FMBs due July 11, 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.

Cash Flows From Investing Activities

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

Cash Used for Investing Activities	For the Six Months Ended June 30 2016	2015	Increase (Decrease)
	(In millions)		
Property Additions:			
Regulated Distribution	$575	$592	$ (17)
Regulated Transmission	509	551	(42)
Competitive Energy Services	382	317	65
Corporate / Other	26	26	—
Nuclear fuel	188	97	91
Investments	49	62	(13)
Asset removal costs	63	67	(4)
Other	(25)	(19)	(6)
	$1,767	$1,693	$ 74

Cash used for investing activities for the first six months of 2016 increased $74 million, compared to the same period of 2015, primarily due to increases in nuclear fuel and property additions. 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 June 30, 2016, was approximately $3.5 billion, as summarized below:

Guarantees and Other Assurances	Maximum Exposure (In millions)
FE's Guarantees on Behalf of its Subsidiaries	
Energy and Energy-Related Contracts(1)	$ 33
Deferred compensation arrangements	544
Other(2)	13
	590
Subsidiaries’ Guarantees	
Energy and Energy-Related Contracts(3)	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	383
Surety Bonds	22
FES' LOC (long-term tax-exempt debt)(4)	93
LOCs(5)	99
	597
Total Guarantees and Other Assurances	$ 3,526

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

(2) Includes guarantees of $4 million for nuclear decommissioning funding assurances, $5 million for railcar leases and $4 million for various leases.

(3) Includes energy and energy-related contracts associated with FES of approximately $248 million.

(4) Reflects the $1 million of interest coverage portion of LOCs issued in support of floating rate PCRBs with various maturities and the principal amount of floating-rate PCRBs of $92 million, all of which is reflected in currently payable long-term debt on FirstEnergy's consolidated balance sheets.

(5) Includes $7 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, $1 million issued in connection with railcar leases 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 June 30, 2016, FES has posted collateral of $145 million.

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

Subsequent to the occurrence of a senior unsecured credit rating downgrade to below S&P's BBB- and Moody's Baa3, or a “material adverse event,” the immediate posting of collateral or accelerated payments may be required of FE or its subsidiaries. The following table discloses the additional credit contingent contractual obligations that may be required under certain events as of June 30, 2016:

Collateral Provisions	FES/ AE Supply (Tied to FE Corp. Rating) (In millions)	FES/ AE Supply (Tied to FES Rating)	Utilities	Total
Split Rating (One rating agency's rating below investment grade)	$ 25	$ 174	$ 44	$ 243
Non-Investment Grade Ratings (All Rating Agencies at or below BB+/Ba1)	$ 25	$ 187	$ 44	$ 256
Total Exposure from Contractual Obligations	$ 25	$ 310	$ 44	$ 379

Excluded from the preceding table are the potential collateral obligations due to affiliate transactions between the Regulated Distribution segment and CES segment. As of June 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 $880 million as of June 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 June 30, 2016, FirstEnergy's leasehold interest was 2.60% of Beaver Valley Unit 2 and 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 June 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	$ 5	$—	$—	$—	$ —	$9
Other external sources[2]	12	5	(22)	(29)	—	—	(34)
Prices based on models	5	2	—	—	(10)	—	(3)
Total[3]	$21	$ 12	$(22)	$(29)	$(10)	$ —	$(28)

(1) Represents exchange traded New York Mercantile Exchange futures and options.
(2) Primarily represents contracts based on broker and ICE quotes.
(3) Includes $(123) 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 June 30, 2016, not subject to regulatory accounting, an increase in commodity prices of 10% would decrease net income by approximately $33 million during the next 12 months.

Equity Price Risk

As of June 30, 2016, the FirstEnergy pension plan assets were allocated approximately as follows: 41% in equity securities, 35% in fixed income securities, 8% in absolute return strategies, 10% in real estate and 6% 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 six months ended June 30, 2016, FirstEnergy made a $160 million contribution to its qualified pension plan. Additionally, in July 2016 FirstEnergy contributed $85 million to its qualified pension plan at FES. 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 June 30, 2016, FirstEnergy's pension plan assets earned approximately 8.1% 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 June 30, 2016, approximately 62% of the funds were invested in fixed income securities, 31% of the funds were invested in equity securities and 7% 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 $1,516 million, $770 million and $163 million for fixed income securities, equity securities and short-term investments, respectively, as of June 30, 2016, excluding $7 million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $77 million reduction in fair value as of June 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 six months ended June 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. At this time, FirstEnergy is unable to determine or project the mark-to-market adjustment that may be recorded as of December 31, 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 for that three-year period, of which $32 million was incurred through June 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 is expected to complete its review in the third quarter of 2016.

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

On 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. JCP&L requested that the proposed new rates take effect in January 2017. On July 13, 2016, this matter was submitted to the Office of Administrative Law for hearing and the issuance of an Initial Decision. A procedural schedule has not yet been issued.

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. On July 18, 2016, the procedural schedule was set with evidentiary hearings in late October and early November of 2016. See Transfer of Transmission Assets to MAIT in FERC Matters below for further discussion of this transaction.

OHIO

The Ohio Companies operated under their ESP 3 plan which expired on May 31, 2016. On May 18, 2016, in response to previous appeals, the Supreme Court of Ohio issued its Opinion affirming in all respects the PUCO's ESP 3 Order.

The Ohio Companies filed an application with the PUCO on August 4, 2014 seeking approval of their ESP IV entitled Powering Ohio's Progress. The Ohio Companies filed a Stipulation and Recommendation on December 22, 2014, and supplemental stipulations and recommendations on May 28, 2015, and June 4, 2015. On December 1, 2015, the Ohio Companies filed a Third Supplemental Stipulation and Recommendation, which included PUCO Staff as a signatory party in addition to other signatories.

The material terms of ESP IV, as modified by the stipulations included:

- An eight-year term (June 1, 2016 - May 31, 2024);
- Contemplates continuing a base distribution rate freeze through May 31, 2024;
- An Economic Stability Program that flows through charges or credits through Rider RRS representing the net result of the price paid to FES through an eight-year FERC-jurisdictional PPA, referred to as the ESP IV PPA, for the output of the ESP IV PPA Facilities against the revenues received from selling such output into the PJM markets;
- Continuing to provide power to non-shopping customers at a market-based price set through an auction process;
- Continuing Rider DCR with increased revenue caps of approximately $30 million per year 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;
- A risk-sharing mechanism that would provide guaranteed credits under Rider RRS in years five through eight to customers as follows: $10 million in year five, $20 million in year six, $30 million in year seven and $40 million in year eight;
- A continuing commitment not to recover from retail customers certain costs related to transmission cost allocations for the longer of the five-year period from June 1, 2011 through May 31, 2016 or when the amount of such costs avoided by customers for certain types of products totals $360 million, including such costs from MISO along with such costs from PJM, subject to the outcome of certain FERC proceedings;
- 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 by February 29, 2016, 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; and
- A contribution of $1 million per year ($8 million over the eight-year term) to establish a Customary Advisory Council to ensure preservation and growth of the competitive market in Ohio.

On March 31, 2016, the PUCO issued an Opinion and Order adopting and approving, with modifications, the Ohio Companies’ ESP IV. Certain changes arising from the approval of ESP IV went into effect on June 1, 2016. The PUCO’s modifications of ESP IV, among others, included:

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- Limiting average customer bill amounts for the first two years of the plan, subject to certain exceptions, and permitting deferral for the second year;
- Prohibiting recovery of retirement costs of the ESP IV PPA Facilities through Rider RRS;
- Assigning the burden of capacity performance penalties incurred by the ESP IV PPA Facilities to the Ohio Companies, rather than customers, and to provide that all capacity performance bonuses earned by the ESP IV PPA Facilities be retained by the Ohio Companies, rather than customers; and
- Providing for the modification of the severability provision previously included in ESP IV, to also address potential future PJM Tariff or rule changes prohibiting the Ohio Companies from offering output of the ESP IV PPA Facilities into PJM auctions.

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 companies desired to transact under the agreement. Pursuant to FERC's directives in the order, FES and the Ohio Companies submitted required compliance filings. FES and the Ohio Companies did not file the ESP IV PPA for FERC review, but rather agreed to suspend the ESP IV PPA prior to transacting thereunder, pending the outcome of the PUCO and FERC proceedings.

On April 29, 2016 and May 2, 2016, applications for rehearing on the Ohio Companies ESP IV were filed with the PUCO by several parties, including the Ohio Companies. As part of the Ohio Companies’ application for rehearing, the Ohio Companies proposed a modified Rider RRS. The PUCO issued an Entry on Rehearing on May 11, 2016 granting the applications for rehearing for the purpose of further consideration of the matters raised therein. On June 29, 2016, PUCO Staff filed testimony recommending that the Ohio Companies’ modified Rider RRS proposal be denied, and instead recommended a new Distribution Modernization Rider providing for the collection of $131 million annually for three years with a possible extension for an additional two years. The hearing began on July 11, 2016 for the modified Rider RRS proposal. On July 25, 2016, the Ohio Companies filed testimony that continues to recommend that the PUCO approve the proposed modified Rider RRS and that the revenues and expenses of the proposed modified Rider RRS be excluded from the significantly excessive earnings test. The Ohio Companies' filing also provided testimony that a properly designed Distribution Modernization Rider would be valued at $558 million annually for 8 years, include an additional amount, as determined by the PUCO, that recognizes the value of the economic impact of FirstEnergy maintaining its headquarters in Ohio, and would also be excluded from the significantly excessive earnings test.

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

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 an order by May 1, 2016, so the revised rule could be in effect for the May 2016 BRA, and also 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. FERC took no action on the complaint prior to the BRA, and therefore the proposed MOPR was not in effect for the auction. Subsequently, certain municipal and industrial customers and a regulated utility, not affiliated with the Ohio Companies, filed a motion to dismiss the complaint as moot in light of FERC’s April 27, 2016 orders on, among other things, the ESP IV PPA and the resulting suspension of the ESP IV PPA. 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. A hearing in this matter has been scheduled for October 11, 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. The matter has been scheduled for oral argument on August 17, 2016.

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.

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.

On November 3, 2015, the Pennsylvania Companies filed their 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. A hearing was held on February 25, 2016. A Joint Petition for Settlement resolving all issues was filed on April 1, 2016 and was approved by the PPUC on May 19, 2016.

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 filed their Phase III

EE&C plans for the June 2016 through May 2021 period on November 23, 2015, which are designed to achieve the targets established in the PPUC's Phase III Final Implementation Order. EDCs are permitted to recover costs for implementing their EE&C plans. On February 10, 2016, the Pennsylvania Companies and the parties intervening in the PPUC's Phase III proceeding filed a joint settlement resolving all issues, which was subject to PPUC approval. On March 10, 2016, the PPUC entered an Opinion and Order approving the settlement and directing that the Pennsylvania Companies modify certain cost recovery methodologies to describe the allocation of EE&C Phase III common costs among customer classes and to describe the recovery of remaining costs of their Phase II EE&C Plans. None of the parties to the joint settlement elected to withdraw from the joint settlement due to the modifications. On May 24, 2016, the PPUC issued a Secretarial Letter permitting the as filed EE&C rates for the Pennsylvania Companies to become effective on June 1, 2016.

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. A procedural schedule has been set with hearings commencing on September 6, 2016. The proposed new rates are expected to take effect in January 2017, pending regulatory approval.

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. A final order consistent with the Motion is expected in the near future. 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 $9.9 million and would be recovered through the existing energy efficiency rider which is reviewed in the fuel (ENEC) case each year. A hearing is scheduled to commence on August 18, 2016. MP and PE are requesting WVPSC approval by October 1, 2016 so MP and PE can implement the programs beginning January 1, 2017.

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, to which the settling parties, including ATSI and the Utilities, responded on July 15, 2016. On July 15, 2016, and July 25, 2016, the protesting parties filed 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 intend to submit responses to the motions to strike, and to the further comments of the protesting parties.

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 expects to intervene and 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. FirstEnergy and the other PJM TOs are evaluating whether to seek rehearing of FERC’s order.

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

The outcome of 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. If approved, JCP&L, ME, and PN will contribute their transmission assets at net book value and an allocated portion of goodwill in a tax-free exchange to MAIT, which will operate similar to FET's two existing stand-alone transmission subsidiaries, ATSI and TrAIL. MAIT's transmission facilities will remain under the functional control of PJM, and PJM will provide transmission service using these facilities under the PJM Tariff. FERC approved the transaction on February 18, 2016. The PPUC approved the transaction on July 21, 2016, subject to the entry of a final order. Upon receipt of all applicable regulatory approvals with respect to the transfer, MAIT expects to file a Section 204 application with FERC, and other necessary filings with the PPUC and the NJBPU, seeking authorization to issue equity to FET, JCP&L, PN and ME for their respective contributions, and to issue debt. MAIT will also make a Section 205 formula rate application with FERC to establish its transmission rate. See New Jersey and Pennsylvania in State Regulation above for further discussion of this transaction.

California Claims Litigation

In October 2006, several California governmental and utility parties presented AE Supply with a settlement proposal to resolve alleged overcharges for power sales by AE Supply to the California Energy Resource Scheduling division of the CDWR during 2001. The settlement proposal claims that CDWR is owed approximately $190 million for these alleged overcharges. This proposal was made in the context of mediation efforts by FERC and the Ninth Circuit in several pending proceedings to resolve all outstanding refund and other claims, including claims of alleged price manipulation in the California energy markets during 2000 and 2001. The Ninth Circuit had previously remanded one of those proceedings to FERC, which dismissed the claims of the California parties in May 2011. The California parties appealed FERC's decision back to the Ninth Circuit. AE Supply joined with other intervenors in the case and filed a brief in support of FERC's dismissal of the case. On April 29, 2015, the Ninth Circuit remanded the case to FERC for further proceedings. On November 3, 2015, FERC set for hearing and settlement procedures the remanded issue of whether any individual public utility seller’s violation of FERC’s market-based rate quarterly reporting requirement led to an unjust and unreasonable rate for that particular seller in California during the 2000-2001 period. Settlement discussions under a FERC-appointed settlement judge are ongoing. On March 1, 2016, FERC issued an order on rehearing clarifying the scope of the evidentiary hearing and the standard of review on remand. In particular, FERC clarified that certain bilateral transactions, including those of AE Supply to the California parties, are protected by the Mobile-Sierra standard, which requires a demonstration of harm to the public interest to determine liability and obligation to make refunds. The California parties requested rehearing of FERC’s March 1, 2016 order; FERC's order on rehearing remains pending. The California Parties also appealed FERC’s November 3, 2015, and March 1, 2016 orders to the Ninth Circuit, which has stayed its review pending the outcome of the ongoing proceeding discussed above.

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

The outcome of either of the above matters or estimate of loss or range of loss cannot be predicted at this time.

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 proposed a CSAPR update rule on November 16, 2015, that would reduce summertime NOx emissions from power plants in 23 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.

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 $253 million has been spent through June 30, 2016 ($108 million at CES and $145 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 that excuses FG's performance under its coal transportation contract with these parties. Specifically, the dispute arises from a contract for the transportation by BNSF and CSX of a minimum of 3.5 million tons of coal annually through 2025 to certain coal-fired power plants owned by FG that are located in Ohio. As a result of and in compliance with MATS, those plants were deactivated by April 16, 2015. In January 2012, FG notified BNSF and CSX that MATS constituted a force majeure event under the contract that excused FG's further performance. Separately, on August 4, 2015, BNSF and CSX submitted to the AAA office in Washington, D.C., a demand for arbitration and statement of claim against FG alleging that FG breached the contract and that FG's declaration of a force majeure under the contract is not valid and seeking damages 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 expected to begin in November 2016, and, if necessary, a damages hearing is expected to begin in May 2017. The decision on liability is expected to be issued within sixty days from the end of the liability hearings. FirstEnergy and FES continue to believe that MATS constitutes a force majeure event under the contract as it relates to the deactivated plants and that FG's performance under the contract is therefore excused. FirstEnergy and FES intend to vigorously assert their position in the arbitration proceedings. If, however, the arbitration panel rules in favor of BNSF and CSX, the results of operations and financial condition of both FirstEnergy and FES could be materially adversely impacted. FirstEnergy and FES are unable to estimate the loss or range of loss.

FG is also a party to another coal transportation contract covering the delivery of 2.5 million tons annually through 2025, a portion of which is to be delivered to another coal-fired plant owned by FG that was deactivated as a result of MATS. FG has asserted a defense of force majeure in response to delivery shortfalls to such plant under this contract as well. If FirstEnergy and FES fail to reach a resolution with the applicable counterparties to the contract, and if it were ultimately determined that, contrary to FirstEnergy's and FES' belief, the force majeure provisions of that contract do not excuse the delivery shortfalls 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 of 2015-2025 remain in dispute.

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

In September 2007, AE received an NOV from the EPA alleging NSR and PSD violations under the CAA, as well as Pennsylvania and West Virginia state laws at the coal-fired Hatfield's Ferry and Armstrong plants in Pennsylvania and the coal-fired Fort Martin and Willow Island plants in West Virginia. The EPA's NOV alleges equipment replacements during maintenance outages triggered the pre-construction permitting requirements under the NSR and PSD programs. On June 29, 2012, January 31, 2013, and March 27, 2013, EPA issued CAA section 114 requests for the Harrison coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2007. On December 12, 2014, EPA issued a CAA section 114 request for the Fort Martin coal-fired plant seeking information and documentation relevant to its operation and maintenance, including capital projects undertaken since 2009. FirstEnergy intends to comply with the CAA but, at this time, is unable to predict the outcome of this matter or estimate the 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, 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 must be ratified by at least 55 countries representing at least 55% of global GHG emissions before its non-binding obligations to limit global warming to well below two degrees Celsius become effective. 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 unexpected, changes in timing and closure plan requirements in the future could impact our asset retirement obligations significantly.

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 June 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 $124 million have been accrued through June 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 June 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. 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.

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 related to the Shield Building analysis in 2016.

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.

NEW ACCOUNTING PRONOUNCEMENTS

In May 2014, the FASB issued, ASU 2014-09 "Revenue from Contracts with Customers", requiring entities to recognize revenue by applying a five-step model in accordance with the core principle to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In addition, the accounting for costs to obtain or fulfill a contract with a customer is specified and disclosure requirements for revenue recognition are expanded. In August 2015, the FASB issued a final ASU deferring the effective date until fiscal years beginning after December 15, 2017. Earlier application is permitted only as of annual reporting periods beginning after December 15, 2016, (the original effective date). In March 2016, the FASB issued ASU 2016-08, “Principal versus Agent Considerations (Reporting Revenue Gross versus Net)", clarifying the principal versus agent implementation guidance in the following areas: unit of account at which the principal/agent determination is made; applying the control principle to certain types of transactions and the control principle and principal/agent indicators. In April 2016, the FASB issued ASU 2016-10, “Identifying Performance Obligations and Licensing”, clarifying the identification of performance obligations and the licensing implementation guidance. In May 2016, the FASB issued ASU 2016-11, “Rescission of SEC Guidance Because of Accounting Standards Updates 2014-09 and 2014-16 Pursuant
to Staff Announcements at the March 3, 2016 EITF Meeting”, rescinding certain SEC Staff Observer comments that are codified in Topic 605, Revenue Recognition, and Topic 932, Extractive Activities-Oil and Gas, effective upon adoption of Topic 606. In May 2016, FASB issued ASU 2016-12 "Narrow-Scope Improvements and Practical Expedients", which is intended to not change the core principle of the guidance in Topic 606, but rather affect only the narrow aspects of Topic 606 by reducing the potential for diversity in practice at initial application and by reducing the cost and complexity of applying Topic 606 both at transition and on an ongoing basis. 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 FirstEnergy or its subsidiaries. See Note 7, Variable Interest Entities, for additional information.

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 will elect 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 for interim periods with 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.

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)",and
- ASU 2016-07, “Simplifying the Transition to the Equity Method of Accounting”.

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

FIRSTENERGY SOLUTIONS CORP.

MANAGEMENT’S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

FES is a wholly owned subsidiary of FE. FES provides energy-related products and services to retail and wholesale customers, and through its principal subsidiaries, FG and NG, owns or leases, operates and maintains FirstEnergy’s fossil and hydroelectric generation facilities (excluding AE Supply and MP), and owns, through its subsidiary, NG, FirstEnergy’s nuclear generation facilities. FENOC, a wholly owned subsidiary of FE, operates and maintains the nuclear generating facilities. FES purchases the entire output of the generation facilities owned by FG, NG and AE Supply, as well as the output relating to leasehold interests of OE and TE in Beaver Valley Unit 2 which remains subject to sale and leaseback arrangements, and pursuant to full output, cost-of-service PSAs.

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

The ESP IV, as modified and approved by the PUCO in March 2016, included an Economic Stability Program that relied upon a PPA between the Ohio Companies and FES, referred to as the ESP IV PPA, which was the subject of a complaint before FERC. FES and the Ohio Companies entered into the ESP IV PPA on April 1, 2016. On April 27, 2016, FERC issued an Order rescinding the existing affiliate waiver between the Ohio Companies and FES as it applies to the ESP IV PPA, precluding implementation of the ESP IV PPA without prior authorization from FERC. FES and the Ohio Companies did not file the ESP IV PPA for FERC review, but rather agreed to suspend the ESP IV PPA prior to transacting thereunder, pending the outcome of the PUCO and FERC proceedings. Several parties filed protests and comments to the compliance filings. The compliance filings and responses thereto are pending before FERC. As the ESP IV PPA is suspended, FES will not realize the revenues originally intended by the arrangement, which could have further material and adverse impacts to the credit ratings, results of operations and financial condition of FES. Also, in response to the Ohio Companies' filing of the modified Rider RRS proposal with the PUCO, several parties filed protests and comments with FERC, alleging, among other things, that the modified Rider RRS constitutes a "virtual PPA". The filings and responses thereto are pending before FERC.

Current market dynamics continue to challenge FES. FES will continue to review the economics of all generating units on an ongoing basis, and is expected to be cash flow positive 2016 through 2018 each year, with the ability to reinvest in its own business and cover currently anticipated capital expenditures during that time. FirstEnergy does not intend to infuse additional equity into FES in order to support their credit ratings. Furthermore, FES delayed its Beaver Valley Unit 2 steam generator replacement project from 2020 to 2023. FES will continue to invest in its nuclear units in order to maintain safe and reliable operations in accordance with nuclear industry standards. Market conditions will continue to impact capital investments in the fossil fleet, with current conditions favoring limited investments.

Competitive markets continue to challenge coal and nuclear baseload generation within FirstEnergy’s footprint. Because FES is subject to wholesale market prices and capacity auction prices, which continue to be depressed, FirstEnergy and FES' future results of operations and financial condition could be negatively and materially impacted.

Further, as FirstEnergy continues to advocate for reforms that ensure competitive wholesale markets adequately value baseload generation, which is essential to maintaining grid reliability, if FES determines that these options are not possible or are only possible for a portion of its fleet and market conditions continue to be depressed, FES may consider other options, including the sale or deactivation of generating plants. No assurance can be given, however, that any such options will be realized.

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

As a result of low capacity prices associated with the 2019/2020 BRA in May 2016, as well as an update to its fundamental long-term capacity and energy price forecast, FES recorded a pre-tax charge of approximately $23 million associated with an impairment of goodwill. Additionally on July 19, 2016, FirstEnergy and FES committed to exit operations of Units 1-4 of the W. H. Sammis generating station (720 MW) by May 31, 2020 and the Bay Shore Unit 1 generating station (136 MW) by October 1, 2020, resulting in non-cash pre-tax impairment charges of $517 million. While FirstEnergy and FES made the decision to sell or deactivate the unit at Bay Shore and deactivate Sammis Units 1-4, deactivation is subject to review by PJM.

Through its own facilities and purchased power agreements with affiliates described above, based upon present forward market indicators it is anticipated that FES 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 FES' entitlement in OVEC. In 2017 and going forward, FES expects to hedge 75% - 85% of its generation output by targeting approximately 50 to 65 million MWHs in annual retail and wholesale contract sales and maintaining up to 25 million MWHs as reserve margin. For the period July 1, 2016 to December 31, 2016, FES' generation supply, including committed purchases, is 100% hedged against committed sales, assuming normal weather conditions. Contractual sales obligations for the periods July 1, 2016 to December 31, 2016 and 2017 are approximately 31 million MWHs and 51 million MWHs, respectively.

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

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

Results of Operations

Operating results decreased $283 million in the first six months of 2016, compared to the same period of 2015, primarily from higher capacity revenue resulting from higher capacity auction prices. Additionally, operating results were impacted by charges associated with the impairments of goodwill, Units 1-4 of the W. H. Sammis generating station, and the Bay Shore Unit 1 generating station, settlement and termination costs associated with coal contracts, partially offset by higher net mark-to-market gains on commodity contract positions. Furthermore, lower sales volumes were offset by lower fuel, purchased power and transmission expenses.

Revenues -

Total revenues decreased $195 million, in the first six months of 2016, compared to the same period of 2015, primarily due to lower sales volumes resulting from the continuation of FES' strategy to more effectively hedge its generation. Revenues were also impacted by higher capacity revenues and higher 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 Six Months Ended June 30 2016	2015	Increase (Decrease)
	(In millions)		
Contract Sales:			
Direct	$402	$717	$ (315)
Governmental Aggregation	431	506	(75)
Mass Market	85	160	(75)
POLR	282	445	(163)
Structured Sales	265	246	19
Total Contract Sales	1,465	2,074	(609)

Wholesale	712	244	468
Transmission	37	83	(46)
Other	87	95	(8)
Total Revenues	$2,301	$2,496	$ (195)

MWH Sales by Channel	For the Six Months Ended June 30 2016	2015	Increase (Decrease)
	(In thousands)		
Contract Sales:			
Direct	7,478	13,319	(43.9)%
Governmental Aggregation	6,560	8,052	(18.5)%
Mass Market	1,239	2,340	(47.1)%
POLR	4,632	7,742	(40.2)%
Structured Sales	6,534	5,673	15.2 %
Wholesale	3,959	161	NM
Total MWH Sales	30,402	37,287	(18.5)%

NM - Not Meaningful

The following table summarizes the price and volume factors contributing to changes in revenues in the first six months of 2016 compared with the same period of 2015:

MWH Sales Channel:	Source of Change in Revenues Increase (Decrease) Sales Volumes	Prices	Gain on Settled Contracts	Capacity Revenue	Total
	(In millions)				
Direct	$(315)	$ —	$ —	$ —	$(315)
Governmental Aggregation	(94)	19	—	—	(75)
Mass Market	(76)	1	—	—	(75)
POLR	(179)	16	—	—	(163)
Structured Sales	37	(18)	—	—	19
Wholesale	66	31	122	249	468

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 1.5 million as of June 30, 2016, compared to 1.9 million as of June 30, 2015. Although unit pricing was higher year-over-year in the Governmental Aggregation and Mass Market channels, the increase was primarily attributable to higher capacity expense as discussed below, which is a component of the retail price.

The decrease in POLR sales of $163 million was due to lower volumes, partially offset by higher rates associated with recent POLR auctions. Structured Sales increased $19 million primarily due to higher volumes, partially offset by the impact of lower market prices.

Wholesale revenues increased $468 million, primarily due to an increase in capacity revenue from higher capacity auction prices, higher net gains on financially settled contracts and an increase in short-term (net hourly position) transactions at higher rates. 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 $46 million in the first six months of 2016, as compared to the same period of 2015, primarily due to lower congestion revenues associated with less volatile market conditions.

Other revenues decreased $8 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 $162 million in the first six months of 2016 compared to the same period of 2015.

The following table summarizes the factors contributing to the changes in fuel and purchased power costs in the first six months of 2016 compared with the same period of 2015:

	Source of Change Increase (Decrease)				
Operating Expense	Volumes	Prices	Loss on Settled Contracts	Capacity Expense	Total
	(In millions)				
Fossil Fuel	$(78)	$(22)	$ 70	$ —	$(30)
Nuclear Fuel	3	(1)	—	—	2
Affiliated Purchased Power	12	(39)	129	—	102
Non-affiliated Purchased Power	(340)	(31)	55	24	(292)

Fossil and nuclear fuel costs decreased $28 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 fuel contracts. Additionally, fuel costs were impacted by $58 million in settlement and termination costs on coal contracts recognized in the second quarter of 2016.

Affiliated purchased power costs increased $102 million, primarily associated with net losses on settled contracts with AE Supply resulting from lower wholesale spot market prices in the first six months of 2016, as compared to the same period of 2015.

Non-affiliated purchased power costs decreased $292 million due to lower volumes ($340 million) and lower prices ($31 million), partially offset by higher capacity expenses ($24 million) and higher losses on financially settled purchased power contracts ($55 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. Lower unit prices and higher losses on financially settled contracts were both due to lower wholesale spot market prices in the first six months of 2016, as compared to the same period of 2015. The increase in capacity expense, which is a component of FES' retail price, was primarily the result of higher capacity rates associated with FES' retail sales obligations.

Other operating expenses decreased $141 million in the first six months of 2016, compared to the same period of 2015, primarily due to the following:

- Fossil operating costs increased $10 million primarily due to increased outage costs.

- Nuclear operating costs decreased $33 million as a result of lower planned refueling outage costs. There was one planned refueling outage during the first six months of 2016 as compared to two planned refueling outages during the same period of 2015.

- Retirement benefit costs increased $15 million.

- Transmission expenses decreased $129 million, primarily due to lower congestion and market-based ancillary costs associated with less volatile market conditions as compared to the first six months of 2015, as well as lower load requirements.

- Other operating expenses decreased $4 million, primarily due to a $14 million increase in mark-to-market gains on commodity contract positions, lower lease expense as a result of the expiration of a nuclear sale-leaseback agreement and lower retail-related costs.

Depreciation expense increased $6 million as a result of a higher asset base.

General taxes decreased $9 million, primarily due to lower gross receipts taxes associated with decreased retail sales.

Impairment of assets increased $524 million due to the 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, resulting in an impairment of $517 million.

Other Expense —

Total other income (expense) decreased $19 million in the first six months of 2016, compared to the same period of 2015, primarily due to lower OTTI on NDT investments.

Income Tax Benefits —

FES' effective tax rate for the six months ended June 30, 2016 and 2015 was 16.6% and 20.0%, respectively. The decrease in the effective tax rate is primarily due to valuation allowances of $65 million recorded against state and local NOL carryforwards that management believes, more likely than not, will not be realized as well as the impairment of goodwill which is non-deductible for tax purposes.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

ITEM 4. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

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

(b) Changes in Internal Control over Financial Reporting

During the quarter ended June 30, 2016, there were no changes in internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, FE's and FES' internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Information required for Part II, Item 1 is incorporated by reference to the discussions in Note 11, Regulatory Matters, and Note 12, Commitments, Guarantees and Contingencies, of the Combined Notes to the Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q.

ITEM 1A. RISK FACTORS

In addition to the other information set forth in this report including, without limitation, the first below revised and updated risk factor and the new additional risk factor, the reader should carefully consider the factors discussed in "Item 1A. Risk Factors" in the Registrants' Annual Report on Form 10-K for the year ended December 31, 2015, which could materially affect the Registrants' business, financial condition or future results.

Should there be a Denial of the Modified RRS Proposal associated with the Ohio Companies' ESP IV, then there may be a Material and Adverse Impact to the Credit Ratings, Results of Operations and Financial Condition of FE

The Ohio Companies’ modified Rider RRS proposal is currently under consideration by the PUCO in connection with the rehearings for the Ohio Companies’ ESP IV. Additionally, several parties have filed protests at FERC alleging, among other things, that the modified Rider RRS constitutes a "virtual PPA" in lieu of the ESP IV PPA. On June 29, 2016, PUCO Staff filed testimony in connection with the ESP IV rehearing recommending that the Ohio Companies' modified Rider RRS proposal be denied, and instead recommended a new Distribution Modernization Rider providing for the collection of $131 million annually for three years with a possible extension for an additional two years. On July 25, 2016, the Ohio Companies filed rebuttal testimony that, among other things, continues to recommend that the PUCO approve the proposed modified Rider RRS, while also properly valuing the Distribution Modernization Rider by the PUCO's Staff. Any denial, invalidation or modification of the Ohio Companies' modified RRS approach, or the PUCO's adoption of the recommended Distribution Modernization Rider without the Ohio Companies' proposed modifications, could impose significant risks on our operations and materially and adversely impact the credit ratings, results of operations and financial condition of FE.

Continued depressed prices in the wholesale energy and capacity markets may further negatively and materially impact the future results of operations and financial condition of FE and FES and could result in FE and FES exploring business alternatives, including the sale or deactivation of additional generating units, which may have a further material adverse effect on the results of operations and financial condition of FE and FES

As the ESP IV PPA is suspended, FES will not realize the revenues originally intended by the arrangement, which could have further material and adverse impacts to the credit ratings, results of operations and financial condition of FES. Further, depressed prices in the wholesale energy and capacity markets continue to challenge the coal and nuclear baseload generating units within the CES business segment, including those of FES. The continued depression of these markets may further negatively and materially impact the credit ratings, future results of operations and financial condition of FE and FES.

FE does not intend to infuse additional equity into CES, including FES, in order to support their credit ratings. However, FE continues to evaluate alternative options that would de-risk the competitive generation fleet and convert MWs from competitive markets to a regulated or regulated-like construct. Market conditions will continue to impact capital investments in the fossil fleet, with current conditions involving favoring limited investments. No assurance can be given, however, that such expectations will not change or that the alternatives for CES, including FES, such as those discussed in “Management’s Discussion and Analysis of Registrant and Subsidiaries – Executive Summary”, are viable or will be achieved or sufficiently realized. If options that retain the current fleet cannot be implemented, can only be implemented for a portion of the CES fleet, including FES, or market conditions continue to be depressed, we may consider other options, including the sale or deactivation of additional generating units within CES, including FES, which may have a further material adverse effect on the results of operations and financial condition of FE and FES.

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

None

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable

ITEM 5. OTHER INFORMATION

None

ITEM 6. EXHIBITS

Exhibit Number	
FirstEnergy	
(A) 10.1	Unit Power Agreement, dated as of April 1, 2016, by and among FirstEnergy Solutions Corp., and Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company.
(A) 12	Fixed charge ratio
(A) 31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a)
(A) 31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a)
(A) 32	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350
101	The following materials from the Quarterly Report on Form 10-Q of FirstEnergy Corp. for the period ended June 30, 2016, formatted in XBRL (Extensible Business Reporting Language): (i) Consolidated Statements of Income (Loss) and Consolidated Statements of Comprehensive Income (Loss), (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Cash Flows, (iv) related notes to these financial statements and (v) document and entity information.
FES	
(A) 10.1	Unit Power Agreement, dated as of April 1, 2016, by and among FirstEnergy Solutions Corp., and Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company. (Incorporated by reference to FE's Form 10-Q, Exhibit 10.1 filed herewith, File No. 333-21011.)
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(A) Provided herein in electronic format as an exhibit.

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

SIGNATURES

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

July 28, 2016

FIRSTENERGY CORP.
Registrant

FIRSTENERGY SOLUTIONS CORP.
Registrant

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

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