FIRSTENERGY CORP
Form 10-Q
July 31, 2018

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, 2018

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

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

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
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and "emerging growth company" in Rule 12b-2 of the Exchange Act.
Large Accelerated Filer þ

Accelerated Filer o

Non-accelerated Filer (Do not check
if a smaller reporting company) o

Smaller Reporting Company o

Emerging Growth Company o

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standard provided pursuant to Section 13(a) of the Exchange Act. o
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
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 JULY 27, 2018
FirstEnergy Corp., $0.10 par value	486,021,499

FirstEnergy Web Site and Other Social Media Sites and Applications

FirstEnergy's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, amendments to those reports and all other documents filed with or furnished to the SEC pursuant to Section 13(a) of the Securities Exchange Act of 1934 are made available free of charge on or through the "Investors" page of FirstEnergy's web site at www.firstenergycorp.com. The public may also read and copy any reports or other information that FirstEnergy files with the SEC at the SEC's public reference room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the SEC's public reference room by calling the SEC at 1-800-SEC-0330. These documents are also available to the public from commercial document retrieval services and the website maintained by the SEC at www.sec.gov.

These SEC filings are posted on the web site as soon as reasonably practicable after they are electronically filed with or furnished to the SEC. Additionally, FirstEnergy routinely posts additional important information, including press releases, investor presentations and notices of upcoming events under the "Investors" section of FirstEnergy's web site and recognizes 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 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. 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 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.

Forward-Looking Statements: This Form 10-Q includes forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 based on information currently available to management. Such statements are subject to certain risks and uncertainties and readers are cautioned not to place undue reliance on these forward-looking statements. 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 (see Glossary of Terms for definitions of capitalized terms):

- The ability to successfully execute an exit of commodity-based generation that minimizes cash outflows and associated liabilities, including, without limitation, the losses, guarantees, claims and other obligations of FirstEnergy as such relate to the entities previously consolidated into FirstEnergy, including FES and FENOC, which have filed for bankruptcy protection.
- The potential for litigation and payment demands against FirstEnergy by FES, FENOC or their creditors, and the ability to successfully execute a definitive settlement agreement and obtain approvals from the Bankruptcy Court and others necessary for the comprehensive settlement as agreed to in principle.
- The risks associated with the bankruptcy cases of FES and FENOC, including, but not limited to, third-party motions in the cases that could adversely affect FirstEnergy, its liquidity or results of operations.
- The ability to experience growth in the Regulated Distribution and Regulated Transmission segments and the effectiveness of our strategy to operate as a fully regulated business.
- The accomplishment of our regulatory and operational goals in connection with our transmission and distribution investment plans.
- Changes in assumptions regarding economic conditions within our territories, assessment of the reliability of our transmission and distribution system, or the availability of capital or other resources supporting identified transmission and distribution investment opportunities.
- The ability to accomplish or realize anticipated benefits from strategic and financial goals, including, but not limited to, the ability to grow earnings in our regulated businesses, continue to reduce costs through FE Tomorrow and other initiatives and to successfully execute our financial plans designed to improve our credit metrics and strengthen our balance sheet.
- The risks and uncertainties associated with litigation, arbitration, mediation and like proceedings.
- The uncertainties associated with the deactivation of our remaining commodity-based generating units, including the impact on vendor commitments, and as it relates to the reliability of the transmission grid, the timing thereof.
- Costs being higher than anticipated and the success of our policies to control costs.
- 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.
- 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.
- Economic and weather conditions affecting future sales, margins and operations, such as significant weather events, and all associated regulatory events or actions.
- Changes in national and regional economic conditions affecting FirstEnergy and/or our major industrial and commercial customers, and other counterparties with which we do business.
- The impact of labor disruptions by our unionized workforce.
- 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.
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- 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.
- The impact of the federal regulatory process on FERC-regulated entities and transactions, in particular FERC regulation of PJM wholesale energy and capacity markets and cost-of-service rates, as well as 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.
- The ability to comply with applicable state and federal reliability standards and energy efficiency and peak demand reduction mandates.
- Other legislative and regulatory changes, including the federal administration's required review and potential revision of environmental requirements, including, but not limited to, the effects of the EPA's CPP, CCR, and CSAPR programs, including our estimated costs of compliance, CWA waste water effluent limitations for power plants, and CWA 316(b) water intake regulation.
- Changing market conditions that could affect the measurement of certain liabilities and the value of assets held in our pension trusts and other trust funds, and cause us and/or our subsidiaries to make additional contributions sooner, or in amounts that are larger, than currently anticipated.
- The impact of changes to significant accounting policies.

- The impact of any changes in tax laws or regulations, including the Tax Act, or adverse tax audit results or rulings.
- The ability to access the public securities and other capital and credit markets in accordance with our financial plans, the cost of such capital and overall condition of the capital and credit markets affecting us and our subsidiaries.
- Further actions that may be taken by credit rating agencies that could negatively affect us and/or our subsidiaries' access to financing, increase the costs thereof, LOCs and other financial guarantees, and the impact of these events on the financial condition and liquidity of FE and/or its subsidiaries.
- Issues concerning the stability of domestic and foreign financial institutions and counterparties with which we do business.
- The risks and other factors discussed from time to time in our SEC filings, and other similar factors.

Dividends declared from time to time on FE's common stock, and thereby on FE's preferred 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.

These forward-looking statements are also qualified by, and should be read together with, the risk factors included in FirstEnergy's filings with the SEC, including but not limited to this Quarterly Report on Form 10-Q, which risk factors supersede and replace the risk factors contained in the Annual Report on Form 10-K and previous Quarterly Report on Form 10-Q, and any subsequent Quarterly Reports on Form 10-Q or Current Reports on Form 8-K. The foregoing review of factors also should not be construed as exhaustive. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor assess the impact of any such factor on FirstEnergy's business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. FirstEnergy expressly disclaims any obligation to update or revise, 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, which subsequently merged with and into FE on January 1, 2014
AESC	Allegheny Energy Service Corporation, a subsidiary of FirstEnergy Corp.
AE Supply	Allegheny Energy Supply Company, LLC, an unregulated generation subsidiary of FE
AGC	Allegheny Generating Company, formerly a generation subsidiary of AE Supply that became a subsidiary of MP in May 2018.
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
BSPC	Bay Shore Power Company
BU Energy	Buchanan Energy Company of Virginia, LLC, a subsidiary of AE Supply, and formerly a 50% owner in a joint venture that owns the Buchanan Generating Facility
Buchanan Energy	Buchanan Generation, LLC, formerly a joint venture between AE Supply and CNX Gas Corporation
CEI	The Cleveland Electric Illuminating Company, an Ohio electric utility operating subsidiary
CES	Competitive Energy Services, formerly a reportable operating segment of FirstEnergy
FE	FirstEnergy Corp., a public utility holding company
FENOC	FirstEnergy Nuclear Operating Company, a subsidiary of FE, which operates NG's nuclear generating facilities
FES	FirstEnergy Solutions Corp., together with its consolidated subsidiaries, FG, NG, FE Aircraft Leasing Corp., Norton Energy Storage L.L.C. and FGMUC, which provides unregulated 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
FGMUC	FirstEnergy Generation Mansfield Unit 1 Corp., a wholly owned subsidiary of FG, which has certain leasehold interests in a portion of Unit 1 at the Bruce Mansfield plant
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	Global Rail Group, LLC, a subsidiary of Global Holding that owns coal transportation operations near Roundup, Montana
GPU	GPU, Inc., former parent of JCP&L, ME and PN, that merged with FE on November 7, 2001
JCP&L	Jersey Central Power & Light Company, a New Jersey electric utility operating subsidiary
MAIT	Mid-Atlantic Interstate Transmission, LLC, a subsidiary of FET, which owns and operates 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 wholly owned 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
Signal Peak	Signal Peak Energy, LLC, 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

GLOSSARY OF TERMS, Continued

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

AAA	American Arbitration Association
ADIT	Accumulated Deferred Income Taxes
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
ARO	Asset Retirement Obligation
ARP	Alternative Revenue Program
ARR	Auction Revenue Right
ASC	Accounting Standard Codification
ASU	Accounting Standards Update
Bankruptcy Court	U.S. Bankruptcy Court in the Northern District of Ohio in Akron
BGS	Basic Generation Service
BNSF	BNSF Railway Company
BRA	PJM RPM Base Residual Auction
CAA	Clean Air Act
CCR	Coal Combustion Residuals
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act of 1980
CFR	Code of Federal Regulations
CO_2	Carbon Dioxide
CPP	EPA's Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
CSX	CSX Transportation, Inc.
CTA	Consolidated Tax Adjustment
CWA	Clean Water Act
DCR	Delivery Capital Recovery
DMR	Distribution Modernization Rider
DOE	United States Department of Energy
DPM	Distribution Platform Modernization
DR	Demand Response
DSIC	Distribution System Improvement Charge
DSP	Default Service Plan
EDC	Electric Distribution Company
EDCP	Executive Deferred Compensation Plan
EE&C	Energy Efficiency and Conservation
EGS	Electric Generation Supplier
EKPC	East Kentucky Power Cooperative, Inc.
ELPC	Environmental Law & Policy Center
EmPOWER Maryland	EmPOWER Maryland Energy Efficiency Act
ENEC	Expanded Net Energy Cost
EPA	United States Environmental Protection Agency
EPS	Earnings per Share
ERO	Electric Reliability Organization

ESP IV	Electric Security Plan IV
ESP IV PPA	Unit Power Agreement entered into on April 1, 2016 by and between the Ohio Companies and FES
Facebook®	Facebook is a registered trademark of Facebook, Inc.
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FE Tomorrow	FirstEnergy's initiative launched in late 2016 to identify its optimal organization structure and properly align corporate costs and systems to efficiently support a fully regulated company going forward

GLOSSARY OF TERMS, Continued

Fitch	Fitch Ratings
FMB	First Mortgage Bond
FPA	Federal Power Act
FRR	Fixed Resource Requirement
FTR	Financial Transmission Right
GAAP	Accounting Principles Generally Accepted in the United States of America
GHG	Greenhouse Gases
HCl	Hydrochloric Acid
ICE	Intercontinental Exchange, Inc.
IIP	Infrastructure Investment Program
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
JCP&L Reliability Plus	JCP&L Reliability Plus Infrastructure Investment Program
kV	Kilovolt
KWH	Kilowatt-hour
LBR	Little Blue Run
LOC	Letter of Credit
LS Power	LS Power Equity Partners III, LP
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	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
NJAPA	New Jersey Administrative Procedure Act
NJBPU	New Jersey Board of Public Utilities
NOAC	Northwest Ohio Aggregation Coalition
NOL	Net Operating Loss
NOPR	Notice of Proposed Rulemaking
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
OCA	Office of Consumer Advocate
OCC	Ohio Consumers' Counsel

OMAEG	Ohio Manufacturers' Association Energy Group
OPEB	Other Post-Employment Benefits
OPIC	Other Paid-in Capital
ORC	Ohio Revised Code
OTTI	Other Than Temporary Impairments

GLOSSARY OF TERMS, Continued

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
Regulation FD	Regulation Fair Disclosure promulgated by the SEC
REIT	Real Estate Investment Trust
RFC	ReliabilityFirst Corporation
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
ROE	Return on Equity
RRS	Retail Rate Stability
RSS	Rich Site Summary
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
RWG	Restructuring Working Group
S&P	Standard & Poor’s Ratings Service
SB310	Substitute Ohio Senate Bill No. 310
SBC	Societal Benefits Charge
SEC	United States Securities and Exchange Commission
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
Tax Act	Tax Cuts and Jobs Act, adopted December 22, 2017
TDS	Total Dissolved Solid
TMI-2	Three Mile Island Unit 2
TO	Transmission Owner
Twitter®	Twitter is a registered trademark of Twitter, Inc.

UCC	Official committee of unsecured creditors appointed in connection with the FES Bankruptcy
U.S. Court of Appeals for the D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
VEPCO	Virginia Electric and Power Company
VIE	Variable Interest Entity

GLOSSARY OF TERMS, Continued

VMP	Vegetation Management Plan
VMS	Vegetation Management Surcharge
VSCC	Virginia State Corporation Commission
WVDEP	West Virginia Department of Environmental Protection
WVPSC	Public Service Commission of West Virginia

PART I. FINANCIAL INFORMATION

ITEM I. Financial Statements

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
(In millions, except per share amounts)	2018	2017	2018	2017
REVENUES:				
Regulated Distribution	$2,352	$2,271	$4,928	$4,771
Regulated Transmission	341	327	664	640
Other	11	26	88	68
Total revenues[(1)]	2,704	2,624	5,680	5,479
OPERATING EXPENSES:				
Fuel	177	163	364	367
Purchased power	698	650	1,523	1,441
Other operating expenses	705	675	1,667	1,332
Provision for depreciation	299	254	593	504
Amortization (deferral) of regulatory assets, net	(107)	78	(255)	161
General taxes	245	230	504	472
Total operating expenses	2,017	2,050	4,396	4,277
OPERATING INCOME	687	574	1,284	1,202
OTHER INCOME (EXPENSE):				
Miscellaneous income, net	48	11	115	25
Interest expense	(369)	(248)	(619)	(493)
Capitalized financing costs	16	14	31	26
Total other expense	(305)	(223)	(473)	(442)
INCOME BEFORE INCOME TAXES	382	351	811	760
INCOME TAXES	115	132	367	284
INCOME FROM CONTINUING OPERATIONS	267	219	444	476
Discontinued operations (Note 3)[(2)]	32	(45)	1,224	(97)
NET INCOME	$299	$174	$1,668	$379
INCOME ALLOCATED TO PREFERRED STOCKHOLDERS (Note 4)	165	—	304	—
NET INCOME ATTRIBUTABLE TO COMMON STOCKHOLDERS	$134	$174	$1,364	$379

EARNINGS PER SHARE OF COMMON STOCK (Note 4):				
Basic - Continuing Operations	$0.22	$0.49	$0.29	$1.07
Basic - Discontinued Operations	0.06	(0.10)	2.57	(0.21)
Basic - Net Income Attributable to Common Stockholders	$0.28	$0.39	$2.86	$0.86
Diluted - Continuing Operations	$0.22	$0.49	$0.29	$1.07
Diluted - Discontinued Operations	0.06	(0.10)	2.56	(0.22)
Diluted - Net Income Attributable to Common Stockholders	$0.28	$0.39	$2.85	$0.85
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING:				
Basic	477	444	477	443
Diluted	479	445	478	444
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$—	$—	$0.72	$0.72

(1) Includes excise tax collections of $87 million and $91 million in the three months ended June 30, 2018 and 2017, respectively, and $189 million and $191 million in the six months ended June 30, 2018 and 2017, respectively.

(2) Net of income tax benefits of $30 million and $15 million for the three months ended June 30, 2018 and 2017, respectively, and income tax benefits of $920 million and $41 million for the six months ended June 30, 2018 and 2017, respectively.

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
(In millions)	2018	2017	2018	2017
NET INCOME	$299	$174	$1,668	$379
OTHER COMPREHENSIVE INCOME (LOSS):				
Pension and OPEB prior service costs	(19)	(18)	(37)	(36)
Amortized losses on derivative hedges	2	1	17	4
Change in unrealized gains on available-for-sale securities	—	(2)	(106)	14
Other comprehensive loss	(17)	(19)	(126)	(18)
Income tax benefits on other comprehensive loss	(4)	(7)	(57)	(7)
Other comprehensive loss, net of tax	(13)	(12)	(69)	(11)
COMPREHENSIVE INCOME	$286	$162	$1,599	$368

The accompanying 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, 2018	December 31, 2017
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$256	$ 588
Restricted cash	68	51
Receivables-		
Customers, net of allowance for uncollectible accounts of $49 in 2018 and 2017	1,231	1,282
Affiliated companies, net of allowance for uncollectible accounts of $632	87	—
Other, net of allowance for uncollectible accounts of $2 in 2018 and $1 in 2017	177	170
Materials and supplies, at average cost	281	262
Prepaid taxes and other	263	151
Current assets - discontinued operations	—	606
	2,363	3,110
PROPERTY, PLANT AND EQUIPMENT:		
In service	38,334	37,270
Less — Accumulated provision for depreciation	10,463	10,098
	27,871	27,172
Construction work in progress	1,150	1,004
	29,021	28,176
PROPERTY, PLANT AND EQUIPMENT, NET - DISCONTINUED OPERATIONS	—	1,057
INVESTMENTS:		
Nuclear plant decommissioning trusts	806	822
Nuclear fuel disposal trust	252	251
Other	255	255
Investments - discontinued operations	—	1,875
	1,313	3,203
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	5,618	5,618
Regulatory assets	84	40
Other	572	697
Deferred charges and other assets - discontinued operations	—	356
	6,274	6,711
	$38,971	$ 42,257
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$1,132	$ 558
Short-term borrowings	1,664	300
Accounts payable	909	827
Accrued taxes	508	533
Accrued compensation and benefits	264	257
Collateral	34	39
Other	557	626
Current liabilities - discontinued operations	—	973

	5,068	4,113
CAPITALIZATION:		
Stockholders' equity-		
Common stock, $0.10 par value, authorized 700,000,000 shares - 477,513,738 and 445,334,111 shares outstanding as of June 30, 2018 and December 31, 2017, respectively	48	44
Mandatorily convertible preferred stock, $100 par value, authorized 5,000,000 shares - 1,616,000 shares issued and outstanding as of June 30, 2018	162	—
Other paid-in capital	11,975	10,001
Accumulated other comprehensive income	73	142
Accumulated deficit	(4,559)	(6,262)
Total stockholders' equity	7,699	3,925
Long-term debt and other long-term obligations	16,461	18,816
	24,160	22,741
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	2,622	3,171
Retirement benefits	2,717	3,975
Regulatory liabilities	2,537	2,720
Asset retirement obligations	589	570
Adverse power contract liability	113	130
Other	1,165	1,438
Noncurrent liabilities - discontinued operations	—	3,399
	9,743	15,403
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 14)		
	$38,971	$ 42,257

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	For the Six Months Ended June 30, 2018	2017
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$1,668	$379
Adjustments to reconcile net income to net cash from operating activities-		
Gain on deconsolidation, net of tax (Note 3)	(1,239)	—
Depreciation and amortization, including nuclear fuel, regulatory assets, net, intangible assets and deferred debt-related costs	604	829
Deferred income taxes and investment tax credits, net	327	224
Impairment of assets and related charges	—	131
Retirement benefits, net of payments	(97)	17
Pension trust contributions	(1,250)	—
Unrealized (gain) loss on derivative transactions	(10)	53
Changes in current assets and liabilities-		
Receivables	20	83
Materials and supplies	28	(10)
Prepaid taxes and other	(143)	(127)
Accounts payable	50	—
Accrued taxes	(58)	(62)
Accrued compensation and benefits	(76)	(125)
Other current liabilities	(152)	(55)
Collateral, net	(15)	32
Other	55	113
Net cash provided from (used for) operating activities	(288)	1,482
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Long-term debt	450	3,500
Short-term borrowings, net	1,364	—
Preferred stock issuance	1,616	—
Common stock issuance	850	—
Redemptions and Repayments-		
Long-term debt	(2,251)	(735)
Short-term borrowings, net	—	(2,450)
Make-whole premiums paid on debt redemptions	(89)	—
Preferred stock dividend payments	(42)	—
Common stock dividend payments	(343)	(319)
Other	(21)	(52)
Net cash provided from (used for) financing activities	1,534	(56)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(1,307)	(1,254)
Nuclear fuel	—	(134)
Proceeds from asset sales	390	—

Sales of investment securities held in trusts	475	1,257
Purchases of investment securities held in trusts	(508)	(1,305)
Notes receivable from affiliated companies	(500)	—
Asset removal costs	(118)	(79)
Other	3	—
Net cash used for investing activities	(1,565)	(1,515)
Net change in cash and cash equivalents and restricted cash	(319)	(89)
Cash, cash equivalents and restricted cash at beginning of period	643	260
Cash, cash equivalents and restricted cash at end of period	$324	$171
SUPPLEMENTAL CASH FLOW INFORMATION:		
Non-cash transaction, beneficial conversion feature (Note 4)	$296	$—
Non-cash transaction, deemed dividend preferred stock (Note 4)	$(261)	$—

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

FIRSTENERGY CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

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.

FE was incorporated under Ohio law in 1996. FE's principal business is the holding, directly or indirectly, of all of the outstanding equity of its principal subsidiaries: OE, CEI, TE, Penn (a wholly owned subsidiary of OE), JCP&L, ME, PN, FESC, AE Supply, MP, PE, WP, FET and its principal subsidiaries (ATSI, MAIT and TrAIL), and AESC. In addition, FE holds all of the outstanding equity of other direct subsidiaries including: FirstEnergy Properties, Inc., FEV, FELHC, Inc., GPU Nuclear, Inc., and Allegheny Ventures, Inc.

FE and its subsidiaries are principally involved in the transmission, distribution and generation of electricity. FirstEnergy's ten utility operating companies comprise one of the nation's largest investor-owned electric systems, based on serving over six million customers in the Midwest and Mid-Atlantic regions. FirstEnergy's transmission operations include approximately 24,500 miles of lines and two regional transmission operation centers. Additionally, its regulated generation subsidiaries control 3,790 MWs of capacity and AE Supply controls 1,367 MWs of capacity. 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 Annual Report on Form 10-K for the year ended December 31, 2017.

FE and its subsidiaries follow GAAP and comply with the related regulations, orders, policies and practices prescribed by the SEC, FERC, and, as applicable, the NRC, 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 8, "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 and Comprehensive Income.

Certain prior year amounts have been reclassified to conform to the current year presentation, as discussed in "New Accounting Pronouncements" and Note 3, "Discontinued Operations."

FES and FENOC Chapter 11 Filing

On March 31, 2018, FES and FENOC announced that, in order to facilitate an orderly financial restructuring, they filed voluntary petitions under Chapter 11 of the United States Bankruptcy Code with the Bankruptcy Court (which is referred to throughout as the FES Bankruptcy). As a result of the bankruptcy filings, FirstEnergy has concluded that it no longer has a controlling interest in FES or FENOC as the entities are subject to the jurisdiction of the Bankruptcy Court and, accordingly, as of March 31, 2018, FES and FENOC were deconsolidated from FirstEnergy’s consolidated financial statements. FE will account for its investments in FES and FENOC with fair values of zero. FE concluded that in connection with the disposal, FES and FENOC became discontinued operations. In connection with the disposal, FE has recorded a gain on deconsolidation (net of taxes) of approximately $1.2 billion for the six months ended June 30, 2018. See Note 3, "Discontinued Operations," for additional information.

On April 20, 2018, FirstEnergy reached an agreement in principle with two groups of key FES creditors in the FES Bankruptcy. The first is an ad hoc group, which includes a majority of the pollution control revenue bonds supported by notes issued by FG and NG and the holders of senior notes issued by FES, while the second group includes the majority of Bruce Mansfield Unit 1 sale and leaseback transaction certificate holders. On May 7, 2018, FE, FES, the FES ad hoc creditor groups and the UCC entered into a Standstill Agreement, which was previously approved by the Bankruptcy Court, agreeing to keep the terms of the settlement open through August 1, 2018, and to other matters to enable an efficient settlement process, including expedited discovery protocols and transfer restrictions on the FES creditor groups. On July 31, 2018, FirstEnergy reached an updated agreement in principle with the same two groups of key FES creditors in the FES Bankruptcy and added FES, FENOC, and the UCC to such agreement in principle.

In connection with the agreement in principle, the parties also extended the Standstill Agreement until the earlier of the effective date of a plan of reorganization for FES and FENOC or termination of the definitive settlement agreement. The updated agreement in principle includes the following terms, among others:

- FE will pay certain pre-petition FES and FENOC employee-related obligations, which include unfunded pension obligations and other employee benefits, and provides for the waiver of all pre-petition claims against FES and FENOC, including the full borrowings by FES under the $500 million secured credit facility, the $200 million credit agreement being used to support surety bonds, the BNSF/CSX rail settlement guarantee, and FES' and FENOC's unfunded pension obligations.
- The full release of all claims against FirstEnergy by FES, FENOC and their creditors.
- A $225 million cash payment from FirstEnergy.
- Up to a $628 million note from FirstEnergy, which is intended to represent the initial estimated value of the worthless stock deduction associated with the FES Bankruptcy and was designed to trade at par value when issued.
- Transfer of the Pleasants Power Station to FES for the benefit of FES' creditors. Prior to transfer and beginning no later than January 1, 2019, FES to have an economic lease in Pleasants; AE Supply will operate Pleasants until transfer.
- FirstEnergy agrees to credit nine-months of FES' and FENOC's shared service costs beginning as of April 1, 2018, in an amount not to exceed $112.5 million, and FirstEnergy agrees to extend the availability of shared services until no later than June 30, 2020.
- FirstEnergy agrees to fund through its pension plan a pension enhancement should FES offer a voluntary enhanced retirement package in 2019, which is estimated to cost $15 million, and approximately $3 million for other employee benefits.

The timing of and the conditions to FirstEnergy's performance of the terms above are set forth in the agreement in principle. This agreement will be subject to approval by the FE, FES, FENOC and AE Supply Boards of Directors, the execution of definitive agreements and the approval of the Bankruptcy Court. Additionally, the Bruce Mansfield certificate holders' support for the agreement is subject to and conditioned upon the ultimate implementation of the agreed upon treatment of certain claims of the Bruce Mansfield certificate holders. There can be no assurance that a definitive settlement agreement will be finalized and approved and, even if approved, whether the conditions to such settlement will be satisfied, and the actual outcome of this matter may differ materially from the terms of the agreement in principle described herein.

Capitalized Financing Costs

For each of the three months ended June 30, 2018 and 2017, capitalized financing costs on FirstEnergy's Consolidated Statements of Income include $12 million and $9 million, respectively, of allowance for equity funds used during construction and $4 million and $5 million, respectively, of capitalized interest. For each of the six months ended June 30, 2018 and 2017, capitalized financing costs on FirstEnergy's Consolidated Statements of Income include $23 million and $17 million, respectively, of allowance for equity funds used during construction and $8 million and $9 million, respectively, of capitalized interest.

Restricted Cash

Restricted cash primarily relates to the consolidated VIE's discussed in Note 8, "Variable Interest Entities." The cash collected from JCP&L, MP, PE and the Ohio Companies' customers is used to service debt of their respective funding companies.

New Accounting Pronouncements

Recently Adopted Pronouncements

ASU 2014-09, "Revenue from Contracts with Customers" (Issued May 2014 and subsequently updated to address implementation questions): The new revenue recognition guidance establishes a new control-based revenue recognition model, changes the basis for deciding when revenue is recognized over time or at a point in time, provides new and more detailed guidance on specific topics and expands and improves disclosures about revenue. FirstEnergy evaluated its revenues and the new guidance had immaterial impacts to recognition practices upon adoption on January 1, 2018. As part of the adoption, FirstEnergy elected to apply the new guidance on a modified retrospective basis. FirstEnergy did not record a cumulative effect adjustment to retained earnings for initially applying the new guidance as no revenue recognition differences were identified in the timing or amount of revenue. In addition, upon adoption, certain immaterial financial statement presentation changes were implemented. See Note 2, " Revenue," for additional information on FirstEnergy revenues.

ASU 2016-01, "Financial Instruments-Overall: Recognition and Measurement of Financial Assets and Financial Liabilities" (Issued January 2016 and subsequently updated in 2018): ASU 2016-01 primarily affects the accounting for equity investments, financial liabilities under the fair value option, and the presentation and disclosure requirements for financial instruments. FirstEnergy adopted this standard on January 1, 2018, and recognizes all gains and losses for equity securities in income with the exception of those that are accounted for under the equity method of accounting. The NDT equity portfolios of JCP&L, ME and PN will not be impacted as unrealized gains and losses will continue to be offset against regulatory assets or liabilities. As a result of adopting this standard, FirstEnergy recorded a cumulative effect adjustment to retained earnings of $115 million (pre-tax) on January 1, 2018, representing unrealized gains on equity securities with FES NDTs that were previously recorded to AOCI. Following deconsolidation of FES and FENOC, the adoption of this standard is not expected to have a material impact on FirstEnergy's financial statements as the majority of its equity securities are offset against a regulatory asset or liability.

ASU 2016-18, "Restricted Cash" (Issued November 2016): ASU 2016-18 addresses the presentation of changes in restricted cash and restricted cash equivalents in the statement of cash flows. The guidance is required to be applied retrospectively. As a result of adopting this standard, FirstEnergy's statement of cash flows reports changes in the total of cash, cash equivalents, restricted cash and restricted cash equivalents. Prior periods have been recast to conform to the current year presentation.

ASU 2017-01, "Business Combinations: Clarifying the Definition of a Business" (Issued January 2017): ASU 2017-01 assists entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. FirstEnergy adopted ASU 2017-01 on January 1, 2018. The ASU will be applied prospectively to future transactions.

ASU 2017-04, "Goodwill Impairment" (Issued January 2017): ASU 2017-04 simplifies the accounting for goodwill impairment by removing Step 2 of the current test, which requires calculation of a hypothetical purchase price allocation. Under the revised guidance, goodwill impairment will be measured as the amount by which a reporting unit's carrying value exceeds its fair value, not to exceed the carrying amount of goodwill (currently Step 1 of the two-step impairment test). Entities will continue to have the option to perform a qualitative assessment to determine if a quantitative impairment test is necessary. FirstEnergy has elected to early adopt ASU 2017-04 as of January 1, 2018, and will apply this standard on a prospective basis.

ASU 2017-07, "Compensation-Retirement Benefits: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost" (Issued March 2017): ASU 2017-07 requires entities to retrospectively (1) disaggregate the current-service-cost component from the other components of net benefit cost (the other components) and present it with other current compensation costs for related employees in the income statement and (2) present the other components elsewhere in the income statement and outside of income from operations if such a subtotal is presented. In addition, only service costs are eligible for capitalization on a prospective basis. FirstEnergy adopted ASU 2017-07 on January 1, 2018. Because the non-service cost components of net benefit cost are no longer eligible for capitalization after December 31, 2017, FirstEnergy has recognized these components in income as a result of adopting this standard. FirstEnergy reclassified approximately $8 million and $16 million of non-service costs from Other operating expense to Miscellaneous income for the three and six months ended June 30, 2017, respectively.

ASU 2018-02, "Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income" (Issued February 2018): ASU 2018-02 allows entities to reclassify from AOCI to retained earnings stranded tax effects resulting from the Tax Act. FirstEnergy early adopted this standard during the first quarter of 2018 and has elected to present the change in the period of adoption. Upon adoption, FirstEnergy recorded a $22 million cumulative effect adjustment for stranded tax effects, such as pension and OPEB prior service costs and losses on derivative hedges, to retained earnings on January 1, 2018, of which $8 million was related to FES and FENOC.

ASU 2018-05, "Income Taxes (Topic 740): Amendments to SEC Paragraphs Pursuant to SEC Staff Accounting Bulletin No. 118" (Issued March 2018): ASU 2018-05, effective 2018, expands income tax accounting and disclosure guidance to include SAB 118 issued by the SEC in December 2017. SAB 118 provides guidance on accounting for the income tax effects of the Tax Act and among other things allows for a measurement period not to exceed one year for companies to finalize the provisional amounts recorded as of December 31, 2017. See Note 7, "Income taxes," for additional information on FirstEnergy's accounting for the Tax Act.

Recently Issued Pronouncements - The following new authoritative accounting guidance issued by the FASB has not yet been adopted. Unless otherwise indicated, FirstEnergy is currently assessing the impact such guidance may have on its financial statements and disclosures, as well as the potential to early adopt where applicable. FirstEnergy has assessed other FASB issuances of new standards not described below or in the 2017 Annual Report on Form 10-K based upon the current expectation that such new standards will not significantly impact FirstEnergy's financial reporting. Below is an update to the discussion of pronouncements contained in the 2017 Annual Report on Form

10-K.

ASU 2016-02, "Leases (Topic 842)" (Issued February 2016 and subsequently updated to address implementation questions): The new guidance 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. There is an optional transition practical expedient that, if elected, would not require an entity to reconsider its accounting for existing land easements that are not currently accounted for as leases under the current leases guidance. In addition, new qualitative and quantitative disclosures of the amounts, timing, and uncertainty of cash flows arising from leases will be required. The guidance 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 lessors and lessees to recognize and measure leases at the beginning of the earliest period presented (January 1, 2017) or initially apply the requirements of the standard in the period of adoption (January 1, 2019). Any leases that expire before the initial application date will not require any accounting adjustment. FirstEnergy does not plan to adopt these standards early. FirstEnergy expects an increase in assets and liabilities; however, it is currently assessing the impact, including monitoring utility industry implementation guidance, but expects no impact to results of operations or cash flows. FirstEnergy continues to develop its complete lease inventory, as well as identify, assess and document technical accounting issues, policy considerations, financial reporting implications and changes to internal controls and processes. In addition, FirstEnergy is in the process of implementing a third-party software tool that will assist with the initial adoption and ongoing compliance.

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2. REVENUE

FirstEnergy accounts for revenues from contracts with customers under ASC 606, Revenue from Contracts with Customers, which became effective January 1, 2018. As part of the adoption of ASC 606, FirstEnergy applied the new standard on a modified retrospective basis analyzing open contracts as of January 1, 2018. However, no cumulative effect adjustment to retained earnings was necessary as no revenue recognition differences were identified when comparing the revenue recognition criteria under ASC 606 to previous requirements.

Revenue from leases, financial instruments, other contractual rights or obligations and other revenues that are not from contracts with customers are outside the scope of the new standard and accounted for under other existing GAAP. FirstEnergy has elected to exclude sales taxes and other similar taxes collected on behalf of third parties from revenue as prescribed in the new standard. As a result, tax collections and remittances within the scope of this election are excluded from recognition in the income statement and instead recorded through the balance sheet, consistent with FirstEnergy’s accounting process prior to the adoption of ASC 606. Excise and gross receipts taxes that are assessed on FirstEnergy are not subject to the election and are included in revenue. FirstEnergy has elected the optional invoice practical expedient for most of its revenues and, with the exception of JCP&L transmission, utilizes the optional short-term contract exemption for transmission revenues due to the annual establishment of revenue requirements, which eliminates the need to provide certain revenue disclosures regarding unsatisfied performance obligations. For a qualitative overview of FirstEnergy's performance obligations, see below.

FirstEnergy’s revenues are primarily derived from electric service provided by its Utilities and transmission (ATSI, TrAIL and MAIT) subsidiaries.

The following tables represent a disaggregation of revenue from contracts with customers for the three and six months ended June 30, 2018, by type of service from each reportable segment:

	For the Three Months Ended June 30, 2018			
Revenues by Type of Service	Regulated Distribution	Regulated Transmission	Corporate/Other and Reconciling Adjustments [1]	Total
	(In millions)			
Distribution services[2]	$1,228	$ —	$ (43)	$1,185
Retail generation	882	—	(14)	868
Wholesale sales[2]	121	—	84	205
Transmission[2]	—	336	—	336
Other	35	—	—	35
Total revenues from contracts with customers	$2,266	$ 336	$ 27	$2,629
ARP	60	—	—	60
Other non-customer revenue	26	5	(16)	15
Total revenues	$2,352	$ 341	$ 11	$2,704

[1] Includes eliminations and reconciling adjustments of inter-segment revenues.
[2] Includes $8 million in net reductions to revenue related to amounts subject to refund resulting from the Tax Act ($10 million subject to refund at Regulated Distribution, partially offset by $2 million subject to recovery at Regulated Transmission).

Revenues by Type of Service	For the Six Months Ended June 30, 2018			
	Regulated Distribution	Regulated Transmission	Corporate/Other and Reconciling Adjustments [1]	Total
	(In millions)			
Distribution services[2]	$2,509	$ —	$ (55)	$2,454
Retail generation	1,922	—	(28)	1,894
Wholesale sales[2]	244	—	204	448
Transmission[2]	—	655	—	655
Other	70	—		70
Total revenues from contracts with customers	$4,745	$ 655	$ 121	$5,521
ARP	124	—	—	124
Other non-customer revenue	59	9	(33)	35
Total revenues	$4,928	$ 664	$ 88	$5,680

[1] Includes eliminations and reconciling adjustments of inter-segment revenues.
[2] Includes $84 million in reductions to revenue related to amounts subject to refund resulting from the Tax Act ($82 million at Regulated
Distribution and $2 million at Regulated Transmission).

Other non-customer revenue includes revenue from derivatives of $4 million and $14 million for the three and six months ended June 30, 2018, respectively.

Regulated Distribution

The Regulated Distribution segment distributes electricity through FirstEnergy's ten utility operating companies and also controls 3,790 MWs of regulated electric generation capacity located primarily in West Virginia, Virginia and New Jersey. Each of the Utilities earn revenue from state-regulated rate tariffs under which it provides distribution services to residential, commercial and industrial customers in its service territory. The Utilities are obligated under the regulated construct to deliver power to customers reliably, as it is needed, which creates an implied monthly contract with the end-use customer. See Note 13, "Regulatory Matters," for additional information on rate recovery mechanisms. Distribution and electric revenues are recognized over time as electricity is distributed and delivered to the customer and the customers consume the electricity immediately as delivery occurs.

Retail generation sales relate to POLR, SOS, SSO and default service requirements in Ohio, Pennsylvania, New Jersey and Maryland, as well as generation sales in West Virginia that are regulated by the WVPSC. Certain of the Utilities have default service obligations to provide power to non-shopping customers who have elected to continue to receive service under regulated retail tariffs. The volume of these sales varies depending on the level of shopping that occurs. Supply plans vary by state and by service territory. Default service for the Ohio Companies, Pennsylvania Companies, JCP&L and PE's Maryland jurisdiction are provided through a competitive procurement process approved by each state's respective commission.

The following table represents a disaggregation of the Regulated Distribution segment revenue from contracts with distribution service and retail generation customers for the three and six months ended June 30, 2018, by class:

Revenues by Customer Class	For the Three Months Ended June 30,	For the Six Months Ended June 30, 2018

	2018	
	(In millions)	
Residential	$1,255	$2,718
Commercial	570	1,150
Industrial	262	516
Other	23	47
Total Revenues	$2,110	$4,431

Wholesale sales primarily consist of generation and capacity sales into the PJM market from FirstEnergy's regulated electric generation capacity and NUGs. Certain of the Utilities may also purchase power from PJM to supply power to their customers. Generally, these power sales from generation and purchases to serve load are netted hourly and reported gross as either revenues or purchased power on the statements of income based on whether the entity was a net seller or buyer each hour. Capacity revenues are recognized ratably over the PJM planning year at prices cleared in the annual BRA and incremental auctions. Capacity purchases and sales through PJM capacity auctions are reported within revenues on the Consolidated Statements of Income. Certain capacity income (bonuses) and charges (penalties) related to the availability of units that have cleared in the auctions are unknown and not recorded in revenue until, and unless, they occur.

The Utilities' distribution customers are metered on a cycle basis. An estimate of unbilled revenues is calculated to recognize electric service provided from the last meter reading through the end of the month. This estimate includes many factors, among which are historical customer usage, load profiles, estimated weather impacts, customer shopping activity and prices in effect for each class of customer. In each accounting period, the Utilities accrue the estimated unbilled amount as revenue and reverses the related prior period estimate. Customer payments vary by state but are generally due within 30 days.

ASC 606 excludes industry-specific accounting guidance for recognizing revenue from ARPs as these programs represent contracts between the utility and its regulators, as opposed to customers. Therefore, revenue from these programs are not within the scope of ASC 606 and regulated utilities are permitted to continue to recognize such revenues in accordance with existing practice but are presented separately from revenue arising from contracts with customers. FirstEnergy currently has ARPs in Ohio, primarily under rider DMR, and in New Jersey.

Regulated Transmission

The Regulated Transmission segment provides transmission infrastructure owned and operated by ATSI, TrAIL, MAIT and certain of FirstEnergy's utilities (JCP&L, MP, PE and WP) to transmit electricity from generation sources to distribution facilities. The segment's revenues are primarily derived from forward-looking formula rates at ATSI, TrAIL and MAIT, as well as stated transmission rates at JCP&L, MP, PE and WP. Both the forward-looking formula and stated rates recover costs that the regulatory agencies determine are permitted to be recovered and provide a return on transmission capital investment. Under forward-looking formula rates, the revenue requirement is updated annually based on a projected rate base and projected costs, which is subject to an annual true-up based on actual costs. Revenue requirements under stated rates are calculated annually by multiplying the highest one-hour peak load in each respective transmission zone by the approved, stated rate in that zone. Revenues and cash receipts for the stand-ready obligation of providing transmission service are recognized ratably over time.

Effective January 1, 2018, JCP&L is subject to a FERC-approved settlement agreement that provides an annual revenue requirement of $155 million through December 31, 2019 which is recognized ratably as revenue over time.

The following table represents a disaggregation of revenue from contracts with regulated transmission customers for the three and six months ended June 30, 2018, by transmission owner:

Revenues from Contracts with Customers by Transmission Asset Owner	For the Three Months Ended June 30, 2018	For the Six Months Ended June 30, 2018
	(In millions)	
ATSI	$167	$ 325
TrAIL	63	123
MAIT	34	64
Other	72	143
Total Revenues	$336	$ 655

3. DISCONTINUED OPERATIONS

FES, FENOC, BSPC and a portion of AE Supply, representing substantially all of FirstEnergy's operations that previously comprised the CES reportable operating segment, are presented as discontinued operations in FirstEnergy's consolidated financial statements resulting from the FES Bankruptcy and actions taken as part of the strategic review to exit commodity-exposed generation, as discussed below. Prior period results have been reclassified to conform with such presentation as discontinued operations.

FES and FENOC Chapter 11 Filing

As discussed in Note 1, "Organization and Basis of Presentation," on March 31, 2018, FES and FENOC announced the FES Bankruptcy. FirstEnergy concluded that it no longer has a controlling interest in FES or FENOC, as the entities are subject to the jurisdiction of the Bankruptcy Court and, accordingly, as of March 31, 2018, FES and FENOC were deconsolidated from FirstEnergy's consolidated financial statements, and will account for its investments in FES and FENOC with fair values of zero.

By eliminating a significant portion of its competitive generation fleet with the deconsolidation of FES and FENOC, FirstEnergy has concluded FES and FENOC meet the criteria for discontinued operations, as this represents a significant event in management's strategic review to exit commodity-exposed generation and transition to a fully-regulated company.

FES Borrowings from FE

On March 9, 2018, FES borrowed $500 million from FE under the secured credit facility, dated as of December 6, 2016, among FES, as Borrower, FG and NG as guarantors, and FE, as lender, which fully utilized the committed line of credit available under the secured credit facility. Following deconsolidation of FES, FE fully reserved for the $500 million associated with the borrowings under the secured credit facility.

On March 16, 2018, FES and FENOC withdrew from the unregulated companies' money pool, which included FE, FES and FENOC. As of the date of the withdrawal, FES and FENOC owed FE approximately $4 million in unsecured borrowings in the aggregate under the money pool. In addition, as of March 31, 2018, AE Supply had a $102 million outstanding unsecured promissory note owed from FES. Following deconsolidation of FES and FENOC, FE fully reserved the $4 million associated with the outstanding unsecured borrowings under the unregulated companies' money pool and the $102 million associated with the AE Supply unsecured promissory note. For the three months ended June 30, 2018, approximately $8 million of interest was accrued and subsequently reserved.

Services Agreements

FirstEnergy is currently continuing to provide shared services support to FES and FENOC under existing shared services agreements ("Services Agreements"). Under the Services Agreements, costs are directly billed or assigned at no more than cost. The remaining costs are for services that are provided on behalf of more than one company, or costs that cannot be precisely identified and are allocated using formulas provided for in the Services Agreements. Transactions under the Services Agreements are generally settled within 30 days. At this time, FirstEnergy expects to provide shared services support to FES and FENOC under the Services Agreements through at least 2018. Following the deconsolidation of FES and FENOC from FirstEnergy's consolidated financial statements on March 31, 2018, approximately $41 million related to these services were charged to FES by FirstEnergy, which was outstanding as of June 30, 2018.

In addition, on March 16, 2018, FES, FENOC and FESC, entered into the FirstEnergy Solutions Money Pool Agreement in order for FESC to assist FES and FENOC with certain treasury support services under the shared service agreement. FESC is a party to the FirstEnergy Solutions Money Pool Agreement solely in the role as administrator of the money pool arrangement thereunder.

Benefit Obligations

FirstEnergy will retain certain obligations for FES and FENOC employees for services provided prior to emergence from bankruptcy. The retention of this obligation at March 31, 2018, resulted in a liability of $820 million (including EDCP, pension and OPEB) with a corresponding loss from discontinued operations. EDCP, net pension and OPEB costs earned by FES and FENOC employees during bankruptcy are expected to be billed under the Services Agreements, and will be reassessed as the bankruptcy proceedings progress.

Guarantees provided by FE

As discussed in Note 14, "Commitments, Guarantees and Contingencies," FE guaranteed the remaining payments due to CSX and BNSF in connection with the definitive settlement of a dispute regarding a coal transportation agreement. As of March 31, 2018, FE recorded an obligation for this guarantee in other current liabilities with a corresponding loss from discontinued operations. On April 6, 2018, FE paid the remaining $72 million owed under the settlement agreement as a result of the FES Bankruptcy. In addition, as of March 31, 2018, FE recorded, and on May 11, 2018, paid a $58 million obligation for a sale-leaseback indemnity in other current liabilities with a corresponding loss from discontinued operations.

Purchase Power

FES at times provides power through affiliated company power sales to meet a portion of the Utilities' POLR and default service requirements and provide power to certain affiliates' facilities. As of June 30, 2018, the Utilities owed FES approximately $23 million related to these purchases. The terms and conditions of the agreements are generally consistent with industry practices and other third-party arrangements. The Utilities purchased and recognized in continuing operations approximately $71 million and $174 million of power from FES for the three and six months ended June 30, 2018, respectively.

Tax Allocation Agreement

Until FES and FENOC emerge from bankruptcy, it is expected that FES and FENOC will remain parties to the intercompany income tax allocation agreement with FE and its other subsidiaries, which provides for the allocation of consolidated tax liabilities. Net tax benefits attributable to FE are generally reallocated to the subsidiaries of

FirstEnergy that have taxable income. As of June 30, 2018, FE has a $58 million receivable from FES and FENOC, in the aggregate, related to the federal tax obligation.

For U.S. federal income taxes, FES and FENOC will continue to be consolidated in FirstEnergy’s tax return and taxable income will be determined based on the tax basis of underlying individual net assets. Deferred taxes previously recorded on the inside basis differences may not represent the actual tax consequence for the outside basis difference, causing a recharacterization of an existing consolidated-return net operating loss as a future worthless stock deduction (currently estimated at approximately $600 million). The estimated worthless stock deduction is contingent upon the emergence of FES and FENOC from the FES Bankruptcy and such amounts may be impacted by future events.

Competitive Generation Asset Sales

FirstEnergy announced in January 2017 that AE Supply and AGC had entered into an asset purchase agreement with a subsidiary of LS Power, as amended and restated in August 2017, to sell four natural gas generating plants, AE Supply's interest in the Buchanan Generating facility and approximately 59% of AGC's interest in Bath County (1,615 MWs of combined capacity). On

December 13, 2017, AE Supply completed the sale of the natural gas generating plants, with net proceeds of approximately $388 million. On March 1, 2018, AE Supply completed the sale of the Buchanan Generating Facility with net proceeds of approximately $20 million. On May 3, 2018, AE Supply and AGC completed the sale of approximately 59% of AGC's interest in Bath County. Net proceeds were approximately $355 million, which includes adjustments based on the timing of the closing and is subject to other customary post-closing adjustments.

In connection with its obligations under the asset purchase agreement, in June 2018, AE Supply redeemed its $305 million aggregate principal amount of senior notes and on May 3, 2018, AGC optionally redeemed its $100 million aggregate principal amount of senior notes. As a result of these redemptions, "make-whole" premiums of approximately $89 million were required to be paid to the noteholders (reported in continuing operations). Additionally, as a result of the completion of the asset sales to LS Power, AE Supply caused the redemption of $142 million aggregate principal amount of PCRBs and separately, together with MP, caused the redemption of $73.5 million of PCRBs. Also, on May 3, 2018, following closing of the sale by AGC of a portion of its ownership interest in Bath County, AGC completed the redemption of AE Supply's shares in AGC and AGC became a wholly owned subsidiary of MP.

On March 9, 2018, BSPC and FG entered into an asset purchase agreement with Walleye Power, LLC (formerly Walleye Energy, LLC), for the sale of the Bay Shore Generating Facility, including the 136 MW Bay Shore Unit 1 and other retired coal-fired generating equipment owned by FG. The sale is subject to customary and other closing conditions, including regulatory approvals, various third-party consents and approval by the Bankruptcy Court in connection with the FES Bankruptcy. On May 11, 2018, FES filed with the Bankruptcy Court for approval of the sale transaction. On June 14, 2018, the UCC filed a limited objection in the Bankruptcy Court proceeding to approve the sale, contesting the previously agreed purchase price allocation between BSPC and FG, which objection was subsequently resolved. The Bankruptcy Court approved the sale on July 13, 2018, and the transaction was completed on July 31, 2018.

Individually, the AE Supply and BSPC asset sales did not qualify for reporting as discontinued operations. However, the asset sales were part of management’s strategic review to exit commodity-exposed generation and, when considered with FES' and FENOC’s bankruptcy filings on March 31, 2018, represent a collective elimination of substantially all of FirstEnergy’s competitive generation fleet and meet the criteria for discontinued operations.

Summarized Results of Discontinued Operations

Summarized results of discontinued operations for the three and six months ended June 30, 2018 and 2017, were as follows:

(In millions)	For the Three Months Ended June 30, 2018	2017	For the Six Months Ended June 30, 2018	2017
Revenues	$11	$680	$633	$1,369
Fuel	(5)	(180)	(121)	(344)
Purchased power	—	(74)	(53)	(123)
Other operating expenses	—	(282)	(347)	(774)
Provision for depreciation	—	(27)	(46)	(52)
General taxes	—	(23)	(18)	(52)
Impairment of assets	—	(131)	—	(131)
Other expense, net	(4)	(23)	(64)	(31)

Income (Loss) from discontinued operations, before tax	2	(60)	(16)	(138)
Income tax benefit[1]	(30)	(15)	(1)	(41)
Income (Loss) from discontinued operations, net of tax	32	(45)	(15)	(97)
Gain on deconsolidation, net of tax	—	—	1,239	—
Income (loss) from discontinued operations	$32	$(45)	$1,224	$(97)

[1] In conjunction with the sale of an interest in Bath County, AGC wrote-off and recognized as a benefit in discontinued operations its excess deferred tax liabilities of $32 million, created from the Tax Act, since they are not required to be refunded to ratepayers.

The gain on deconsolidation that was recognized in the six months ended June 30, 2018, consisted of the following:

(In millions)	For the Six Months Ended June 30, 2018
Removal of investment in FES and FENOC	$2,193
Assumption of benefit obligations retained at FE (including Pension, OPEB and EDCP)	(820)
Guarantees and credit support provided by FE	(139)
Reserve on receivables and allocated Pension/OPEB mark-to-market	(914)
Gain on deconsolidation of FES and FENOC, before tax	320
Income tax benefit, including estimated worthless stock deduction	919
Gain on deconsolidation of FES and FENOC, net of tax	$1,239

The following table summarizes the major classes of assets and liabilities as discontinued operations as of June 30, 2018 and December 31, 2017:

(In millions)	June 30, 2018	December 31, 2017
Carrying amount of the major classes of assets included in discontinued operations:		
Cash	$ —	$ 1
Restricted cash	—	3
Receivables	—	202
Materials and supplies	—	201
Collateral	—	130
Other current assets	—	69
Total current assets	—	606
Property, plant and equipment	—	1,057
Investments	—	1,875
Other non-current assets	—	356
Total non-current assets	—	3,288
Total assets included in discontinued operations	$ —	$ 3,894
Carrying amount of the major classes of liabilities included in discontinued operations:		
Currently payable long-term debt	$ —	$ 524
Accounts payable	—	200
Accrued taxes	—	38
Accrued compensation and benefits	—	79
Other current liabilities	—	132
Total current liabilities	—	973
Long-term debt and other long-term obligations	—	2,299
Accumulated deferred income taxes [1]	—	(1,812)
Asset retirement obligations	—	1,945
Deferred gain on sale and leaseback transaction	—	723
Other non-current liabilities	—	244
Total noncurrent liabilities	—	3,399

Total liabilities included in discontinued operations	$ —	$ 4,372

(1) Represents an increase in FirstEnergy's ADIT liability as an ADIT asset was removed upon deconsolidation of FES and FENOC.

FirstEnergy's Consolidated Statement of Cash Flows combines cash flows from discontinued operations with cash flows from continuing operations within each cash flow statement category. The following table summarizes the major classes of cash flow items as discontinued operations for the six months ended June 30, 2018 and 2017:

(In millions)	For the Six Months Ended June 30, 2018	2017
CASH FLOWS FROM OPERATING ACTIVITIES:		
Income (loss) from discontinued operations	$1,224	$(97)
Depreciation and amortization, including nuclear fuel, regulatory assets, net, intangible assets and deferred debt-related costs	47	157
Unrealized (gain) loss on derivative transactions	(10)	53
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(15)	(178)
Nuclear fuel	—	(134)
Sales of investment securities held in trusts	109	437
Purchases of investment securities held in trusts	(122)	(466)

4. EARNINGS PER SHARE OF COMMON STOCK

The convertible Preferred Stock issued in January 2018 (see Note 11, "Capitalization") is considered participating securities since these shares participate in dividends on Common Stock on an "as-converted" basis. As a result, EPS of Common Stock is computed using the two-class method required for participating securities.

The two-class method uses an earnings allocation formula that treats participating securities as having rights to earnings that otherwise would have been available only to common stockholders. Under the two-class method, net income attributable to common stockholders is derived by subtracting the following from income from continuing operations:

- preferred share dividends,
- deemed dividends for the amortization of the beneficial conversion feature recognized at issuance of the Preferred Stock (if any), and
- an allocation of undistributed earnings between the common shares and the participating securities (convertible Preferred Stock) based on their respective rights to receive dividends.

Net losses are not allocated to the convertible Preferred Stock as they do not have a contractual obligation to share in the losses of FirstEnergy. FirstEnergy allocates undistributed earnings based upon income from continuing operations.

The Preferred Stock includes an embedded conversion option at a price that is below the fair value of the Common Stock on the commitment date. This beneficial conversion feature, which was approximately $296 million, represents the difference between the fair value per share of the Common Stock and the conversion price, multiplied by the number of common shares issuable upon conversion. The beneficial conversion feature will be amortized as a deemed dividend over the period from the issue date to the first allowable conversion date (July 22, 2018) as a charge to OPIC, since FE is in an accumulated deficit position with no retained earnings to declare a dividend. As noted above, for EPS reporting purposes, this beneficial conversion feature will be reflected in net income attributable to common stockholders as a deemed dividend. The amount amortized for the three and six months ended June 30, 2018, was approximately $148 million and $261 million, respectively.

Basic EPS available to common stockholders is computed by dividing income available to common stockholders by the weighted average number of common shares outstanding during the period. Participating securities are excluded from basic weighted average ordinary shares outstanding. Diluted EPS available to common stockholders is computed by dividing income available to common stockholders by the weighted average number of common shares outstanding, including all potentially dilutive common shares, if the effect of such common shares is dilutive.

Diluted EPS reflects the dilutive effect of potential common shares from share-based awards and convertible preferred shares. The dilutive effect of outstanding share based awards is computed using the treasury stock method, which assumes any proceeds that could be obtained upon the exercise of the award would be used to purchase Common Stock at the average market price for the period. The dilutive effect of the convertible Preferred Stock is computed using the if-converted method, which assumes conversion of the convertible Preferred Stock at the beginning of the period, giving income recognition for the add-back of the preferred share dividends, amortization of beneficial conversion feature, and undistributed earnings allocated to preferred stockholders.

The following table reconciles basic and diluted EPS of common stock:

Reconciliation of Basic and Diluted EPS of Common Stock	For the Three Months Ended June 30, 2018	2017	For the Six Months Ended June 30, 2018	2017
(In millions, except per share amounts)				
EPS of Common Stock				
Income from continuing operations	$267	$219	$444	$476
Less: Preferred dividends	—	—	(43)	—
Less: Amortization of beneficial conversion feature	(148)	—	(261)	—
Less: Undistributed earnings allocated to preferred stockholders[1]	(13)	—	—	—
Income from continuing operations available to common stockholders	106	219	140	476
Discontinued operations, net of tax	32	(45)	1,224	(97)
Less: Undistributed earnings allocated to preferred stockholders	(4)	—	—	—
Income (loss) from discontinued operations available to common stockholders	28	(45)	1,224	(97)
Income available to common stockholders, basic and diluted	$134	$174	$1,364	$379
Share Count information:				
Weighted average number of basic shares outstanding	477	444	477	443
Assumed exercise of dilutive stock options and awards	2	1	1	1
Weighted average number of diluted shares outstanding	479	445	478	444
Income available to common stockholders, per common share:				
Income from continuing operations, basic	$0.22	$0.49	$0.29	$1.07
Discontinued operations, basic	0.06	(0.10)	2.57	(0.21)
Income available to common stockholders, basic	$0.28	$0.39	$2.86	$0.86
Income from continuing operations, diluted	$0.22	$0.49	$0.29	$1.07
Discontinued operations, diluted	0.06	(0.10)	2.56	(0.22)
Income available to common stockholders, diluted	$0.28	$0.39	$2.85	$0.85

(1) Undistributed earnings were not allocated to participating securities for the six months ended June 30, 2018 as income from continuing operations less dividends declared (common and preferred) and deemed dividends were a net loss.

For both the three and six months ended June 30, 2018 and 2017, one million shares from stock options and awards were excluded from the calculation of diluted shares outstanding, as their inclusion would be antidilutive to basic EPS from continuing operations. Also, for the three and six months ended June 30, 2018, 59 million shares associated with the assumed conversion of Preferred Stock were excluded, as their inclusion would be antidilutive to basic EPS from continuing operations.

5. PENSION AND OTHER POSTEMPLOYMENT BENEFITS

The components of the consolidated net periodic costs (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,	2018	2017	2018	2017
	(In millions)			
Service costs	$56	$52	$1	$1
Interest costs	93	97	6	7
Expected return on plan assets	(144)	(112)	(7)	(7)
Amortization of prior service costs (credits)	2	2	(20)	(20)
Net periodic costs (credits)	$7	$39	$(20)	$(19)

Components of Net Periodic Benefit Costs (Credits)	Pension		OPEB	
For the Six Months Ended June 30,	2018	2017	2018	2017
	(In millions)			
Service costs	$112	$104	$2	$2
Interest costs	186	194	12	14
Expected return on plan assets	(288)	(224)	(15)	(15)
Amortization of prior service costs (credits)	4	4	(40)	(40)
Net periodic costs (credits)	$14	$78	$(41)	$(39)

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

	Pension		OPEB	
Net Periodic Benefit Expense (Credit)	2018	2017	2018	2017
	(In millions)			
For the Three Months Ended June 30,	$(18)	$ 27	$(21)	$(14)
For the Six Months Ended June 30,	$(32)	$ 59	$(42)	$(29)

Amounts in the tables above include FES' and FENOC's share of the net periodic pension and OPEB costs (credits) of $13 million and $(10) million, respectively, for the three months ended June 30, 2018, and $26 million and $(20) million, respectively, for the six months ended June 30, 2018. FES' and FENOC's share of the net periodic pension and OPEB costs (credits) were $15 million and $(8) million, respectively, for the three months ended June 30, 2017 and $31 million and $(16) million, respectively, for the six months ended June 30, 2017. Such amounts are a component of Discontinued Operations in FirstEnergy's Consolidated Statements of Income.

Following adoption of ASU 2017-07, "Compensation-Retirement Benefits: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost" in 2018, service costs, net of capitalization, continue to be reported within Other operating expenses on the FirstEnergy Consolidated Statements of Income. Non-service costs are reported within Miscellaneous income, net within Other income (expense). Prior period amounts have been reclassified to conform with current year presentation. See Note 1, "Organization and Basis of Presentation," for additional information.

In January 2018, FirstEnergy satisfied its minimum required funding obligations of $500 million and addressed funding obligations for future years to its qualified pension plan with additional contributions of $750 million.

6. ACCUMULATED OTHER COMPREHENSIVE INCOME

The changes in AOCI, net of tax, in the three and six months ended June 30, 2018 and 2017, for FirstEnergy are included in the following tables:

	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, 2018	$(15)	$ —	$ 101	$86
Amounts reclassified from AOCI[1]	2	—	(19)	(17)
Other comprehensive income (loss)	2	—	(19)	(17)
Income taxes (benefits) on other comprehensive income (loss)	1	—	(5)	(4)
Other comprehensive income (loss), net of tax	1	—	(14)	(13)
AOCI Balance as of June 30, 2018	$(14)	$ —	$ 87	$73
AOCI balance as of April 1, 2017	$(26)	$ 63	$ 138	$175
Other comprehensive income before reclassifications	—	4	—	4
Amounts reclassified from AOCI[1]	1	(6)	(18)	(23)
Other comprehensive income (loss)	1	(2)	(18)	(19)
Income taxes (benefits) on other comprehensive income (loss)	1	—	(8)	(7)
Other comprehensive loss, net of tax	—	(2)	(10)	(12)
AOCI Balance as of June 30, 2017	$(26)	$ 61	$ 128	$163

	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, 2018	$(22)	$ 67	$ 97	$142
Other comprehensive income before reclassifications	—	(97)	—	(97)
Amounts reclassified from AOCI[1][3]	4	(1)	(37)	(34)
Deconsolidation of FES and FENOC	13	(8)	—	5
Other comprehensive income (loss)	17	(106)	(37)	(126)
Income taxes (benefits) on other comprehensive income (loss)	9	(39)	(27)	(57)
Other comprehensive income (loss), net of tax	8	(67)	(10)	(69)
AOCI Balance as of June 30, 2018	$(14)	$ —	$ 87	$73

AOCI Balance as of January 1, 2017	$(28)	$ 52	$ 150	$174
Other comprehensive income before reclassifications	—	36	—	36
Amounts reclassified from AOCI[1]	4	(22)	(36)	(54)
Other comprehensive income (loss)	4	14	(36)	(18)
Income taxes (benefits) on other comprehensive income (loss)	2	5	(14)	(7)
Other comprehensive income (loss), net of tax	2	9	(22)	(11)
AOCI Balance as of June 30, 2017	$(26)	$ 61	$ 128	$163

[1] Amounts in parenthesis represent credits to the Consolidated Statements of Income from AOCI.
[2] Components are included in the computation of net periodic pension cost. See Note 5, "Pension and Other Postemployment Benefits," for additional details.
[3] Includes stranded tax amounts reclassified from AOCI in connection with the adoption of ASU 2018-02, "Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income".

The following amounts were reclassified from AOCI for FirstEnergy in the three and six months ended June 30, 2018 and 2017:

Reclassifications from AOCI[1]	For the Three Months Ended June 30,		For the Six Months Ended June 30,		Affected Line Item in the Consolidated Statements of Income
	2018	2017	2018 [3]	2017	
	(In millions)				
Gains & losses on cash flow hedges					
Long-term debt	$2	$1	$4	$4	Interest expense
	—	(1)	(1)	(2)	Income taxes
	$2	$—	$3	$2	Net of tax
Unrealized gains on AFS securities					
Realized gains on sales of securities	$—	$(4)	$(1)	$(14)	Discontinued Operations
Defined benefit pension and OPEB plans					
Prior-service costs	$(19)	$(18)	$(37)	$(36)	[2]
	4	8	9	14	Income taxes
	$(15)	$(10)	$(28)	$(22)	Net of tax

[1] Amounts in parenthesis represent credits to the Consolidated Statements of Income from AOCI.
[2] Components are included in the computation of net periodic pension cost. See Note 5, "Pension and Other Postemployment Benefits," for additional details.
[3] Includes stranded tax amounts reclassified from AOCI in connection with the adoption of ASU 2018-02, "Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income".

7. INCOME TAXES

FirstEnergy’s interim effective tax rates reflect the estimated annual effective tax rates for 2018 and 2017. 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 on continuing operations for the three months ended June 30, 2018 and 2017, was 30.1% and 37.6%, respectively. The decrease in effective tax rate is primarily due to the Tax Act that decreased the corporate federal income tax rate from 35% to 21%, which became effective January 1, 2018.

FirstEnergy's effective tax rate for the six months ended June 30, 2018 and 2017 was 45.3% and 37.4%, respectively. The increase in effective tax rate is primarily due to the legal and financial separation of FES and FENOC from FirstEnergy. This separation officially eroded the ties between FES, FENOC and other FirstEnergy subsidiaries doing business in West Virginia. As such, FES and FENOC were removed from the West Virginia unitary group when calculating West Virginia state income taxes, resulting in a $126 million charge to income tax expense in continuing operations associated with the re-measurement in state deferred taxes. This increase was partially offset by the Tax Act that decreased the corporate federal income tax rate from 35% to 21%, which became effective January 1, 2018.

At December 31, 2017, FirstEnergy recorded provisional income tax amounts in its accounting for certain effects of the provisions of the Tax Act as allowed under SAB 118. In addition, SAB 118 allowed for a measurement period for companies to finalize the provisional amounts recorded as of December 31, 2017, not to exceed one year. The measurement period adjustments recorded in the first six months of 2018 to the provisional amounts were immaterial. FirstEnergy expects to complete its assessment and record any final adjustments to the provisional amounts by the fourth quarter of 2018, which could result in a material impact to FirstEnergy's income tax provision or financial position.

FirstEnergy's assessment of accounting for the Tax Act is based upon management's current understanding of the Tax Act. However, it is expected that further guidance will be issued during 2018, which may result in adjustments that could have a material impact to FirstEnergy's future results of operations, cash flows, or financial position.

On July 1, 2018, the Governor of New Jersey signed budget legislation that, among other things, enacted unitary combined reporting, imposed a temporary surtax on top of the 9% corporate tax rate, imposed a one-time surtax on certain dividends, requires market-based sourcing for sales of services, and selectively adopts certain aspects of the Tax Act. FirstEnergy is currently assessing the impact such legislation may have on its financial statements.

In March 2018, FirstEnergy recorded unrecognized tax benefits of $49 million, which relates primarily to the tax benefit recognized for the investment in FES and FENOC. The tax impact is reflected in discontinued operations.

On October 18, 2017, the Supreme Court of Pennsylvania affirmed the Commonwealth Court's holding that the state's net loss carryover provision violated the Pennsylvania Uniformity Clause and was unconstitutional. However, the court also opined that the portion of the net loss carryover provision that created the violation may be severed from the statute, enabling the statute to operate as the legislature intended, and on October 30, 2017, the Pennsylvania Governor signed House Bill 542 into law, which, among other things, amended Pennsylvania's limitation on net loss deductions to remove the flat-dollar limitation. On January 4, 2018, the court declined to further hear any arguments related to the matter and, as a result, FirstEnergy withdrew its protective refund claims from the Commonwealth of Pennsylvania on January 30, 2018. Upon doing so, FirstEnergy reversed a previously recorded unrecognized tax benefit of approximately $45 million in the first quarter of 2018, none of which impacted FirstEnergy's effective tax rate.

As of June 30, 2018, it was reasonably possible that approximately $2 million of unrecognized tax benefits may be resolved within the next twelve months as a result of the statute of limitations expiring, none of which would affect FirstEnergy's effective tax rate.

In January 2018, the IRS completed its examination of FirstEnergy's 2016 federal income tax return and issued a Full Acceptance Letter with no changes or adjustments to FirstEnergy's taxable income.

8. 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.

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):

- Ohio Securitization - In September 2012, the Ohio Companies created separate, wholly owned limited liability company 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, 2018 and December 31, 2017, $304 million and $315 million of the phase-in recovery bonds were outstanding, respectively.
- JCP&L Securitization - 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 II and are collateralized by its equity and assets, which consist primarily of bondable transition property. As of June 30, 2018 and December 31, 2017, $49 million and $56 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 limited liability company SPEs 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 limited liability company SPEs, have no recourse to any assets or revenues of the special purpose limited liability companies. As of June 30, 2018 and December 31, 2017, $371 million and $383 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

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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. In 2015, FirstEnergy fully impaired the value of its investment in Global Holding.

As discussed in Note 14, "Commitments, Guarantees and Contingencies," FE is the guarantor under Global Holding's $300 million term loan facility, which matures in March 2020 and has an outstanding principal balance of $235 million as of June 30, 2018. 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, a proposed transmission line from West Virginia through Virginia into Maryland which PJM cancelled in 2012, 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. As of June 30, 2018, the carrying value of the equity method investment was $17 million.

- Purchase Power Agreements - FirstEnergy evaluated its PPAs and determined that certain NUG entities at its Regulated Distribution segment may be VIEs to the extent that they own a plant that sells substantially all of its output to the applicable utilities and the contract price for power is correlated with the plant’s variable costs of production.

FirstEnergy maintains 12 long-term PPAs with NUG entities that were entered into pursuant to PURPA. FirstEnergy was not involved in the creation of, and has no equity or debt invested in, any of these entities. FirstEnergy has determined that for all but one of these NUG entities, it does not have a variable interest or the entities do not meet the criteria to be considered a VIE. FirstEnergy may hold a variable interest in the remaining one entity; however, it applied the scope exception that exempts enterprises unable to obtain the necessary information to evaluate entities. Because FirstEnergy has no equity or debt interests in the NUG entities, its maximum exposure to loss relates primarily to the above-market costs incurred for power. FirstEnergy expects any above-market costs incurred at its Regulated Distribution segment to be recovered from customers. Purchased power costs related to the contract that may contain a variable interest during the three months ended June 30, 2018 and 2017, were $26 million and $25 million, respectively, and $58 million and $53 million during the six months ended June 30, 2018 and 2017, respectively.

- FES and FENOC - As a result of the Chapter 11 bankruptcy filing discussed in Note 3, "Discontinued Operations," FE evaluated its investments in FES and FENOC and determined they are VIEs. FE is not the primary beneficiary because it lacks a controlling interest in FES and FENOC, which are subject to the jurisdiction of the Bankruptcy Court as of March 31, 2018. The carrying values of the equity investments in FES and FENOC were zero at June 30, 2018.

9. 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.

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 10, "Derivative Instruments," for additional information regarding FirstEnergy's FTRs.

NUG contracts represent PPAs with third-party non-utility generators that are transacted to satisfy certain obligations under PURPA. NUG contract carrying values are recorded at fair value and adjusted periodically using a mark-to-model methodology, which approximates market. The primary unobservable inputs into the model are regional power prices and generation MWH. Pricing for the NUG contracts is a combination of market prices for the current year and next two 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, 2018, from those used as of December 31, 2017. 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, 2018. The following tables set forth FirstEnergy's recurring assets and liabilities that are accounted for at fair value by level within the fair value hierarchy:

	June 30, 2018				December 31, 2017			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$474	$—	$474	$—	$476	$—	$476
Derivative assets - FTRs	—	—	5	5	—	—	3	3
Equity securities[(2)]	298	—	—	298	297	—	—	297
Foreign government debt securities	—	16	—	16	—	23	—	23
U.S. government debt securities	—	19	—	19	—	21	—	21
U.S. state debt securities	—	248	—	248	—	247	—	247
Other[(3)]	256	33	—	289	588	38	—	626
Total assets	$554	$790	$5	$1,349	$885	$805	$3	$1,693
Liabilities								
Derivative liabilities - commodity contracts	$—	$—	$—	$—	$—	$(4)	$—	$(4)
Derivative liabilities - FTRs	—	—	(5)	(5)	—	—	—	—
Derivative liabilities - NUG contracts[(1)]	—	—	(65)	(65)	—	—	(79)	(79)
Total liabilities	$—	$—	$(70)	$(70)	$—	$(4)	$(79)	$(83)
Net assets (liabilities)[(4)]	$554	$790	$(65)	$1,279	$885	$801	$(76)	$1,610

(1) NUG contracts are subject to regulatory accounting treatment and changes in market values do not impact earnings.

(2) NDT funds hold equity portfolios whose performance is benchmarked against the S&P 500 Low Volatility High Dividend Index, S&P 500 Index, MSCI World Index and MSCI AC World IMI Index.

(3) Primarily consists of short-term cash investments.

(4) Excludes $(12) million and $(11) million as of June 30, 2018 and December 31, 2017, respectively, of receivables, payables, taxes and accrued income associated with financial instruments reflected within the fair value table.

Rollforward of Level 3 Measurements

The following table provides a reconciliation of changes in the fair value of NUG contracts and FTRs that are classified as Level 3 in the fair value hierarchy for the periods ended June 30, 2018 and December 31, 2017:

	NUG Contracts[1]			FTRs		
	Derivative Assets	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net
	(In millions)					
January 1, 2017 Balance	$1	$ (108)	$(107)	$3	$ (1)	$2
Unrealized gain (loss)	—	(10)	(10)	1	(1)	—
Purchases	—	—	—	3	—	3
Settlements	(1)	39	38	(4)	2	(2)
December 31, 2017 Balance	$—	$ (79)	$(79)	$3	$ —	$3
Unrealized gain (loss)	—	(2)	(2)	1	—	1
Purchases	—	—	—	5	(5)	—
Settlements	—	16	16	(4)	—	(4)
June 30, 2018 Balance	$—	$ (65)	$(65)	$5	$ (5)	$—

(1)NUG contracts are subject to regulatory accounting treatment and changes in market values 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, 2018:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$ —	Model	RTO auction clearing prices	$(1.70) to $5.40	$0.80	Dollars/MWH
NUG Contracts	$ (65)	Model	Generation	400 to 1,660,000	338,000	MWH
			Regional electricity prices	$29.20 to $31.10	$30.20	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 equity securities, AFS debt securities and other investments. FirstEnergy has no debt securities held for trading purposes.

Generally, unrealized gains and losses on equity securities are recognized in income whereas unrealized gains and losses on AFS debt securities are recognized in AOCI. However, the NDTs of JCP&L, ME and PN are subject to regulatory accounting with all gains and losses on equity and AFS debt securities 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.

Nuclear Decommissioning and Nuclear Fuel Disposal Trusts

JCP&L, ME and PN hold debt and equity securities within their respective NDT and nuclear fuel disposal trusts. The debt securities are classified as AFS securities, recognized at fair market value.

The following table summarizes the amortized cost basis, unrealized gains, unrealized losses and fair values of investments held in NDT and nuclear fuel disposal trusts as of June 30, 2018 and December 31, 2017:

	June 30, 2018[1]				December 31, 2017[2]			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
	(In millions)							
Debt securities	$783	$ 2	$ (27)	$ 758	$774	$ 11	$ (17)	$ 768
Equity securities	$265	$ 31	$ (1)	$ 295	$254	$ 40	$ —	$ 294

(1) Excludes short-term cash investments of $5 million
(2) Excludes short-term cash investments of $11 million

Proceeds from the sale of investments in equity and AFS debt securities, realized gains and losses on those sales and interest and dividend income for the three and six months ended June 30, 2018 and 2017, were as follows:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
	(In millions)			
Sale Proceeds	$175	$313	$366	$820
Realized Gains	9	29	28	50
Realized Losses	(11)	(29)	(27)	(44)
Interest and Dividend Income	10	10	20	19

Other Investments

Other investments include employee benefit trusts, which are primarily invested in corporate-owned life insurance policies, and equity method investments. Other investments were $255 million as of June 30, 2018 and December 31, 2017, and 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 FirstEnergy's long-term debt, which excludes capital lease obligations and net unamortized debt issuance costs, premiums and discounts as of June 30, 2018 and December 31, 2017:

	June 30, 2018	December 31, 2017
	(In millions)	
Carrying Value	$17,650	$ 19,425
Fair Value	$18,876	$ 21,551

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, 2018 and December 31, 2017.

10. DERIVATIVE INSTRUMENTS

FirstEnergy is exposed to financial risks resulting from fluctuating interest rates and commodity prices, including prices for electricity, 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 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 $18 million and $22 million as of June 30, 2018 and December 31, 2017, respectively. Based on current estimates, approximately $4 million of these unamortized losses are expected to be amortized to interest expense during the next twelve months.

Refer to Note 6, "Accumulated Other Comprehensive Income," for reclassifications from AOCI during the three and six months ended June 30, 2018 and 2017.

As of June 30, 2018 and December 31, 2017, 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, 2018 and December 31, 2017, 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 $2 million and $3 million as of June 30, 2018 and December 31, 2017, respectively.

NUGs

As of June 30, 2018 and December 31, 2017, FirstEnergy's net liability position under NUG contracts was $65 million and $79 million, respectively, representing contracts held at JCP&L and PN. NUG contracts are classified as an adverse power contract liability on the Consolidated Balance Sheets. During the three and six months ended June 30, 2018, there were settlements of $9 million and $16 million, respectively, and unrealized losses of $2 million for the six months ended June 30, 2018. Changes in the fair value of NUG contracts are subject to regulatory accounting treatment and do not impact earnings.

FTRs

As of June 30, 2018, and December 31, 2017, FirstEnergy's net asset position associated with FTRs was not material. 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.

11. CAPITALIZATION

Stock Issuance

On January 22, 2018, FirstEnergy entered into agreements for the private placement of its equity securities representing an approximately $2.5 billion investment in FE. FE entered into a Preferred Stock Purchase Agreement (the Preferred SPA) for the private placement of 1,616,000 shares of mandatorily convertible preferred stock, designated as the Series A Convertible Preferred Stock, par value $100 per share, representing an investment of nearly $1.62 billion ($162 million of mandatorily convertible preferred stock and $1.46 billion of OPIC). FE also entered into a Common Stock Purchase Agreement for the private placement of

30,120,482 shares of FE’s common stock, par value $0.10 per share, representing an investment of $850 million ($3 million of Common Stock and $847 million of OPIC).

The Preferred Stock participates in dividends on the Common Stock on an as-converted basis based on the number of shares of Common Stock a holder of Preferred Stock would receive if its shares of Preferred Stock were converted on the dividend record date at the conversion price in effect at that time. Such dividends are paid at the same time that the dividends on Common Stock are paid.

Each share of Preferred Stock will be convertible into a number of shares of Common Stock equal to the $1,000 liquidation preference, divided by the Conversion Price then in effect. As of June 30, 2018, the Conversion Price in effect remained $27.42 per share. The Conversion Price is subject to anti-dilution adjustments and adjustments for subdivisions and combinations of the Common Stock, as well as dividends on the Common Stock paid in Common Stock and for certain equity issuances below the Conversion Price then in effect. The Preferred Stock is convertible at the option of holders beginning as of July 22, 2018. Furthermore, the Preferred Stock will automatically convert to Common Stock upon certain events of bankruptcy or liquidation of FE. FE may elect to convert the Preferred Stock if, at any time, fewer than 323,200 shares of Preferred Stock are outstanding. As of July 27, 2018, 224,714 preferred shares have been converted into 8,195,257 common shares at the option of the holders.

In general, any shares of Preferred Stock outstanding on July 22, 2019, will be automatically converted. However, no shares of Preferred Stock will be converted prior to January 22, 2020, if such conversion will cause a converting holder to be deemed to beneficially own, together with its affiliates whose holdings would be aggregated with such holder for purposes of Section 13(d) under the Exchange Act, more than 4.9% of the then-outstanding Common Stock. Furthermore, in no event shall the Company issue more than 58,964,222 shares of Common Stock (the Share Cap) in the aggregate upon conversion of the convertible Preferred Stock. From and after the time at which the aggregate number of shares of Common Stock issued upon conversion of the Preferred Stock equals the Share Cap, each holder electing to convert convertible Preferred Stock will be entitled to receive a cash payment equal to the market value of the Common Stock such holder does not receive upon conversion.

The holders of Preferred Stock have limited class voting rights related to the creation of additional securities that are senior or equal with the Preferred Stock, as well as certain reclassifications and amendments that would affect the rights of the holders of Preferred Stock. The holders of Preferred Stock also have the right to approve issuances of securities convertible or exchangeable for Common Stock, subject to certain exceptions for compensation arrangements and bona fide dividend reinvestment or share purchase plans.

Pursuant to the Preferred SPA, FirstEnergy formed a RWG composed of three employees of FirstEnergy and two outside members identified in the Preferred SPA to advise FirstEnergy management regarding FES' restructuring. The outside RWG members are industry professionals C. John Wilder, Executive Chairman of Bluescape Energy Partners, LLC, and Anthony (Tony) Horton, Chief Financial Officer and Executive Vice President of Energy Future Holdings Corp.

12. ASSET RETIREMENT OBLIGATIONS

FirstEnergy has recognized applicable legal obligations for AROs and their associated cost, primarily for the decommissioning of the TMI-2 nuclear generating facility and environmental remediation, including reclamation of sludge disposal ponds, closure of coal ash disposal sites, underground and above-ground storage tanks and wastewater treatment lagoons. In addition, FirstEnergy has recognized conditional retirement obligations, primarily for asbestos remediation.

FirstEnergy uses an expected cash flow approach to measure the fair value of the nuclear decommissioning and environmental remediation AROs, considering the expected timing of settlement of the ARO based on the expected economic useful life of the plants. Conditional retirement obligations associated with tangible long-lived assets are recognized at fair value in the period in which they are incurred if a reasonable estimate can be made, even though there may be uncertainty about timing or method of settlement.

The aggregate ARO liabilities for FirstEnergy are approximately $589 million and $570 million as of June 30, 2018 and December 31, 2017, respectively.

In April 2015, the EPA finalized regulations for the disposal of CCRs (non-hazardous), establishing national standards for 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. On September 13, 2017, the EPA announced that it would reconsider certain provisions of the final regulations. On July 17, 2018, the EPA Administrator signed a final rule extending the deadline for certain CCR facilities to cease disposal and commence closure activities, as well as, establishing less stringent groundwater monitoring and protection requirements. Based on an assessment of the finalized regulations, the future cost of compliance and expected timing had no significant impact on FirstEnergy's existing AROs associated with CCRs. Although not currently expected, changes in timing and closure plan requirements in the future could materially and adversely impact FirstEnergy's AROs.

13. 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. In addition, if any of the FirstEnergy affiliates were to engage in the construction of significant new transmission facilities, depending on the state, they may be required to obtain state regulatory authorization to site, construct and operate the new transmission facility.

Following the adoption of the Tax Act, various state regulatory proceedings have been initiated to investigate the impact of the Tax Act on the Utilities' rates and charges. State proceedings that have arisen are discussed below. The Utilities continue to monitor and investigate the impact of state regulatory proceedings resulting from the Tax Act.

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. On July 16, 2015, the MDPSC issued an order setting new incremental energy savings goals for 2017 and beyond, beginning with the goal of 0.97% savings achieved under PE's plan for 2016, and increasing 0.2% per year thereafter to reach 2%. The Maryland legislature in April 2017 adopted a statute requiring the same 0.2% per year increase, up to the ultimate goal of 2% annual savings, for the duration of the 2018-2020 and 2021-2023 EmPOWER Maryland program cycles, to the extent the MDPSC determines that cost-effective programs and services are available. PE's approved 2018-2020 EmPOWER Maryland plan continues and expands upon prior years' programs, and adds new programs, for a projected total cost of $116 million over the three-year period. On December 22, 2017, the MDPSC issued an order approving the 2018-2020 plan with various modifications. PE recovers 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 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. 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 2013 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 2013 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, as well as 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

Maryland 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 issued a ruling on any of those matters.

On September 26, 2016, the MDPSC initiated a new proceeding to consider an array of issues relating to electric distribution system design, including matters relating to electric vehicles, distributed energy resources, advanced metering infrastructure, energy storage, system planning, rate design, and impacts on low-income customers. Comments were filed and a hearing was held in late 2016. On January 31, 2017, the MDPSC issued a notice establishing five working groups to address these issues over the following eighteen months, and also directed the retention of an outside consultant to prepare a report on costs and benefits of distributed solar generation in Maryland. On January 19, 2018, PE filed a joint petition, along with other utility companies, work group stakeholders, and the MDPSC electric vehicle work group leader, to implement a statewide electric vehicle portfolio. If approved, PE will launch an electric vehicle charging infrastructure program on January 1, 2019, offering up to 2,000 rebates for electric vehicle charging equipment to residential customers, and deploying up to 259 chargers at non-residential customer service locations at a projected total cost of $12 million. PE is proposing to recover program costs subject to a five-year amortization. On February 6, 2018, the MDPSC opened a new proceeding to consider the petition and numerous parties filed comments on the petition on March 27, 2018, and the MDPSC held a hearing on the petition in May 2018. In an order issued July 2, 2018, the MDPSC directed the parties to conduct more discovery on the matter, then file additional comments by August 30, 2018, after which a second hearing will be conducted in early September 2018.

On January 12, 2018, the MDPSC instituted a proceeding to examine the impacts of the Tax Act on the rates and charges of Maryland utilities. PE was required to track and apply regulatory accounting treatment for the impacts beginning January 1, 2018, and submitted a report to the MDPSC on February 15, 2018, estimating that the Tax Act impacts would be approximately $7 million to $8 million annually for PE’s customers. PE proposed to file a base rate case in the third quarter of 2018 where the benefits from the effects of the Tax Act will be realized by customers through a lower rate increase than would otherwise be necessary.

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.

JCP&L currently operates under rates that were approved by the NJBPU on December 12, 2016, effective as of January 1, 2017. These rates provide an annual increase in operating revenues of approximately $80 million from those previously in place and are intended 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. In addition, on January 25, 2017, the NJBPU approved the acceleration of the amortization of JCP&L’s 2012 major storm expenses that are recovered through the SRC in order for JCP&L to achieve full recovery by December 31, 2019.

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 included operational and financial components. The independent consultant conducting the review issued a final report on July 27, 2016, recognizing that JCP&L is meeting the NJBPU requirements and making various operational and financial recommendations. The NJBPU issued an Order on August 24, 2016, that accepted the independent consultant’s final report and directed JCP&L, the Division of Rate Counsel and other interested parties to address the recommendations.

In an Order issued October 22, 2014, in a generic proceeding to review its policies with respect to the use of a CTA in base rate cases, 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 Superior Court of New Jersey Appellate Division and JCP&L filed to participate as a respondent in that proceeding supporting the order. On September 18, 2017, the Superior Court of New Jersey Appellate Division reversed the NJBPU's Order on the basis that the NJBPU's modification of its CTA methodology did not comply with the procedures of the NJAPA. JCP&L's existing rates are not expected to be impacted by this order. On December 19, 2017, the NJBPU approved the issuance of proposed rules to modify the CTA methodology consistent with its October 22, 2014, Generic Order, which were published in the NJ Register on January 16, 2018, and republished on February 6, 2018, to correct an error. JCP&L filed comments supporting the proposed rulemaking on April 6, 2018.

At the December 19, 2017, NJBPU public meeting, the NJBPU approved its IIP rulemaking. The IIP creates a financial incentive for utilities to accelerate the level of investment needed to promote the timely rehabilitation and replacement of certain non-revenue producing components that enhance reliability, resiliency, and/or safety. On July 13, 2018, JCP&L filed an infrastructure plan, JCP&L Reliability Plus, which proposed to accelerate $386.8 million of electric distribution infrastructure investment over four years to enhance the reliability and resiliency of its distribution system and reduce the frequency and duration of power outages. JCP&L requested that the NJBPU issue a final order in December 2018.

On January 31, 2018, the NJBPU instituted a proceeding to examine the impacts of the Tax Act on the rates and charges of New Jersey utilities. The NJBPU ordered New Jersey utilities to: (1) defer on their books the impacts of the Tax Act effective January 1, 2018; (2) to file tariffs effective April 1, 2018, reflecting the rate impacts of changes in current taxes; and (3) to file tariffs effective July 1, 2018, reflecting the rate impacts of changes in deferred taxes. On March 2, 2018, JCP&L filed a petition with the NJBPU, which included proposed tariffs for a base rate reduction of $28.6 million effective April 1, 2018, and a rider to reflect $1.3 million in rate impacts of changes in deferred taxes. On March 26, 2018, the NJBPU approved JCP&L's rate reduction effective April 1, 2018, on an interim basis subject to refund, pending the outcome of this proceeding. The NJBPU, however, did not address refunds and other proposed rider tariffs at such time, but may be addressed at a later date.

OHIO

The Ohio Companies currently operate under ESP IV which commenced June 1, 2016 and expires May 31, 2024. The material terms of ESP IV, as approved in the PUCO's Opinion and Order issued on March 31, 2016 and Fifth Entry on Rehearing on October 12, 2016, include Rider DMR, which provides for the Ohio Companies to collect $132.5 million annually for three years, with the possibility of a two-year extension. Rider DMR will be grossed up for federal income taxes, resulting in an approved amount of approximately $168 million annually in 2018 and 2019. Revenues from Rider DMR will be excluded from the significantly excessive earnings test for the initial three-year term but the exclusion will be reconsidered upon application for a potential two-year extension. The PUCO set three conditions for continued recovery under Rider DMR: (1) retention of the corporate headquarters and nexus of operations in Akron, Ohio; (2) no change in control of the Ohio Companies; and (3) a demonstration of sufficient progress in the implementation of grid modernization programs approved by the PUCO. ESP IV also continues a base distribution rate freeze through May 31, 2024. In addition, ESP IV continues the supply of power to non-shopping customers at a market-based price set through an auction process.

ESP IV also continues Rider DCR, which supports continued investment related to the distribution system for the benefit of customers, with increased revenue caps of $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. Other material terms of ESP IV include: (1) the collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs; (2) an agreement to file a Grid Modernization Business Plan for PUCO consideration and approval (which filing was made on February 29, 2016, and remains pending); (3) a goal across FirstEnergy to reduce CO_2 emissions by 90% below 2005 levels by 2045; (4) contributions, totaling $51 million to: (a) fund energy conservation programs, economic development and job retention in the Ohio Companies' service territories; (b) establish a fuel-fund in each of the Ohio Companies' service territories to assist low-income customers; and (c) establish a Customer Advisory Agency to ensure preservation and growth of the competitive market in Ohio; and (5) an agreement to file an application to transition to a straight fixed variable cost recovery mechanism for residential customers' base distribution rates, which filing was made on April 3, 2017, and which the PUCO denied on June 13, 2018.

Several parties, including the Ohio Companies, filed applications for rehearing regarding the Ohio Companies' ESP IV with the PUCO. The Ohio Companies' application for rehearing challenged, among other things, the PUCO's failure to adopt the Ohio Companies' suggested modifications to Rider DMR. The Ohio Companies had previously suggested that a properly designed Rider DMR would be valued at $558 million annually for eight years, and include an additional amount that recognizes the value of the economic impact of FirstEnergy maintaining its headquarters in Ohio. Other parties' applications for rehearing argued, among other things, that the PUCO's adoption of Rider DMR is not supported by law or sufficient evidence. On August 16, 2017, the PUCO denied all remaining intervenor applications for rehearing, denied the Ohio Companies' challenges to the modifications to Rider DMR and added a third-party monitor to ensure that Rider DMR funds are spent appropriately. On September 15, 2017, the Ohio Companies filed an application for rehearing of the PUCO's August 16, 2017 ruling on the issues of the third-party monitor and the ROE calculation for advanced metering infrastructure. On October 11, 2017, the PUCO denied the Ohio Companies' application for rehearing on both issues. On October 16, 2017, the Sierra Club and the OMAEG filed notices of appeal with the Supreme Court of Ohio appealing various PUCO entries on their applications for rehearing. On November 16, 2017, the Ohio Companies intervened in the appeal. Additional parties subsequently filed notices of appeal with the Supreme Court of Ohio challenging various PUCO entries on their applications for rehearing. On February 26, 2018, appellants filed their briefs. Briefs of the PUCO and the Ohio Companies were filed on May 29, 2018. On July 9, 2018, appellants filed their reply briefs. On July 30, 2018, OCC, the NOAC, and the OMAEG filed a joint motion with the Supreme Court of Ohio to stay the portions of the PUCO's orders and entries under appeal that authorized Rider DMR. The Ohio Companies responded on July 31, 2018.

Under ORC 4928.66, the Ohio Companies are required to implement energy efficiency programs that achieve certain annual energy savings and total peak demand reductions. Starting in 2017, ORC 4928.66 requires the energy savings benchmark to increase by 1% and the peak demand reduction benchmark to increase by 0.75% annually thereafter through 2020 and the energy savings benchmark to increase by 2% annually from 2021 through 2027, with a cumulative benchmark of 22.2% by 2027. 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 ORC 4928.66 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. On December 9, 2016, the Ohio Companies filed a Stipulation and Recommendation with several parties that contained changes to the plan and a decrease in the plan costs. The Ohio Companies anticipate the cost of the plans will be approximately $268 million over the life of the portfolio plans and such costs are expected to be recovered through the Ohio Companies’ existing rate mechanisms. On November 21, 2017, the PUCO issued an order that approved the filed Stipulation and Recommendation with several modifications, including a cap on the Ohio Companies’ collection of program costs and shared savings set at 4% of the Ohio Companies’ total sales to customers as reported on 2015 FERC Form 1. On December 21, 2017, the Ohio Companies filed an application for rehearing challenging the PUCO’s modification of the Stipulation and Recommendation to include the 4% cost cap, which was denied by the PUCO on January 10, 2018. On March 12, 2018, the Ohio Companies filed a Notice of Appeal with the Supreme Court of Ohio challenging the PUCO’s imposition of a 4% cost cap. Various other parties also filed Notices of Appeal challenging various PUCO entries on their applications for rehearing. The Ohio Companies filed their brief on May 21, 2018.

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, except that in 2014 SB310 froze 2015 and 2016 requirements at the 2014 level (2.5%), pushing back scheduled increases, which resumed in 2017 (3.5%), and increases 1% each year through 2026 (to 12.5%) and shall remain at 12.5% in 2027 and each year thereafter. 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. The OCC and the ELPC also filed appeals of the PUCO's order. On January 24, 2018, the Supreme Court of

Ohio reversed the PUCO order finding that the order violated the rule against retroactive ratemaking. On February 5, 2018, the OCC and ELPC filed a motion for reconsideration, to which the Ohio Companies responded in opposition on February 15, 2018. On April 25, 2018, the Supreme Court of Ohio denied the motion for reconsideration. As a result, the Ohio Companies recognized a pre-tax benefit to earnings (within the Amortization (deferral) of regulatory assets, net line on the Consolidated Statement of Income) of approximately $72 million to reverse the liability associated with the PUCO opinion and order.

On December 1, 2017, the Ohio Companies filed an application with the PUCO for approval of a DPM Plan. The DPM Plan is a portfolio of approximately $450 million in distribution platform investment projects, which are designed to modernize the Ohio Companies' distribution grid, prepare it for further grid modernization projects, and provide customers with immediate reliability benefits. The Ohio Companies have requested that the PUCO issue an order approving the DPM Plan and associated cost recovery so that the Ohio Companies can expeditiously commence the DPM Plan and customers can begin to realize the associated benefits.

On January 10, 2018, the PUCO opened a case to consider the impacts of the Tax Act and determine the appropriate course of action to pass benefits on to customers. The Ohio Companies, effective January 1, 2018, were required to establish a regulatory liability for the estimated reduction in federal income tax resulting from the Tax Act, and filed comments on February 15, 2018, explaining that customers will save nearly $40 million annually as a result of updating tariff riders for the tax rate changes and that the Ohio Companies' base distribution rates are not impacted by the Tax Act changes because they are frozen through May 2024. The Ohio Companies filed reply comments on March 7, 2018.

PENNSYLVANIA

The Pennsylvania Companies operate under DSPs for the June 1, 2017 through May 31, 2019 delivery period, which 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 DSPs, the supply will 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. The DSPs include modifications to the Pennsylvania Companies' POR programs in order to reduce the level of uncollectible expense the Pennsylvania Companies experience associated with alternative EGS charges.

On December 11, 2017, the Pennsylvania Companies filed DSPs for the June 1, 2019 through May 31, 2023 delivery period. Under the 2019-2023 DSPs, the supply is proposed to be provided by wholesale suppliers through a mix of 3, 12 and 24-month energy contracts, as well as two RFPs for 2-year SREC contracts for ME, PN and Penn. The 2019-2023 DSPs as proposed also include modifications to the Pennsylvania Companies' POR programs in order to continue their clawback pilot program as a long-term, permanent program. The 2019-2023 DSPs also introduce a retail market enhancement rate mechanism designed to stimulate residential customer shopping, and modifications to the Pennsylvania Companies' customer class definitions to allow for the introduction of hourly priced default service to customers at or above 100kW. A hearing was held on April 10, 2018, and the ALJ issued a recommended decision dated May 31, 2018. The decision recommended approval of the Pennsylvania Companies' DSPs as originally proposed with two exceptions: it recommended rejecting the proposed retail market enhancement rate mechanism, and establishing limitations on customer assistance program customers' shopping. Exceptions were filed by two parties on June 28, 2018, to which the Pennsylvania Companies filed reply exceptions on July 9, 2018. The PPUC is expected to issue a final order on these DSPs by mid-September 2018.

The Pennsylvania Companies operate under rates that were approved by the PPUC on January 19, 2017, effective as of January 27, 2017. These rates provide annual increases in operating revenues of approximately $96 million at ME, $100 million at PN, $29 million at Penn, and $66 million at WP, and are intended to benefit customers by modernizing the grid with smart technologies, increasing vegetation management activities, and continuing other customer service enhancements.

Pursuant to Pennsylvania's EE&C legislation in Act 129 of 2008 and PPUC orders, Pennsylvania EDCs implement energy efficiency and peak demand reduction programs. On June 19, 2015, the PPUC issued a Phase III Final Implementation Order setting: demand reduction targets, relative to each Pennsylvania Companies' 2007-2008 peak demand (in MW), at 1.8% for ME, 1.7% for Penn, 1.8% for WP, and 0% for PN; and energy consumption reduction targets, as a percentage of each Pennsylvania Companies’ historic 2010 forecasts (in MWH), at 4.0% for ME, 3.9% for PN, 3.3% for Penn, and 2.6% for WP. The Pennsylvania Companies' Phase III EE&C plans for the June 2016 through May 2021 period, which were approved in March 2016, with expected costs up to $390 million, are designed to achieve the targets established in the PPUC's Phase III Final Implementation Order with full recovery through the reconcilable EE&C riders.

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 February 11, 2016, the PPUC approved LTIIPs for each of the Pennsylvania Companies. On June 14, 2017, the PPUC approved modified LTIIPs for ME, PN and Penn for the remaining years of 2017 through 2020 to provide additional support for reliability and infrastructure investments. The LTIIPs estimated costs for the remaining period of 2018 to 2020 are: WP $50.1 million; PN $44.8 million; Penn $33.2 million; and ME $51.3 million. On April 10, 2018, the PPUC notified each of the Pennsylvania Companies that the PPUC was initiating a review of the LTIIPs as required by regulation once every five years, and soliciting comments from interested parties. On May 10, 2018, the Pennsylvania Companies each filed comments explaining that their LTIIPs are effective and that changes to the respective LTIIPs are not necessary. No parties other than the Pennsylvania Companies filed comments.

On February 16, 2016, the Pennsylvania Companies filed riders for PPUC approval for quarterly cost recovery, which were approved by the PPUC on June 9, 2016, and went into effect July 1, 2016, subject to hearings and refund or reallocation among customer classes. On January 19, 2017, in the PPUC's order approving the Pennsylvania Companies' general rate cases, the PPUC added an additional issue to the DSIC proceeding to include whether ADIT should be included in DSIC calculations. On February 2, 2017, the parties to the DSIC proceeding submitted a Joint Settlement to the ALJ that resolved the issues that were pending from the order issued on June 9, 2016. On August 31, 2017, the ALJ issued a decision recommending that the complaint of the Pennsylvania OCA be granted by the PPUC such that the Pennsylvania Companies reflect all federal and state income tax deductions related to DSIC-eligible property in the currently effective DSIC rates. On April 19, 2018, the PPUC approved the Joint Settlement without modification and reversed the ALJ's decision that would have required the Pennsylvania Companies to reflect all federal and state income tax deductions related to DSIC-eligible property in currently effective DSIC rates. On May 21, 2018, the Pennsylvania OCA filed an appeal with the Pennsylvania Commonwealth Court of the PPUC's decision of April 19, 2018. On June 11, 2018, the Pennsylvania Companies filed a Notice of Intervention in the Pennsylvania OCA's appeal to Commonwealth Court.

On February 12, 2018, the PPUC initiated a proceeding to determine the effects of the Tax Act on the tax liability of utilities and the feasibility of reflecting such impacts in rates charged to customers. On March 9, 2018, the Pennsylvania Companies submitted their calculation of the net annual effect of the Tax Act on income tax expense and rate base to be $37 million for ME, $40 million for PN, $9 million for Penn, and $30 million for WP. The Pennsylvania Companies also filed comments proposing that rates be adjusted to reflect the tax rate changes prospectively from the date of a final PPUC order via a reconcilable rider, with the amount that would otherwise accrue between January 1, 2018 and the date of a final order being used to invest in the Pennsylvania Companies' infrastructure. On March 15, 2018, the PPUC issued a Temporary Rates Order making the Pennsylvania Companies' rates temporary and subject to refund for six months. On May 17, 2018, the PPUC issued orders directing that the Pennsylvania Companies implement a reconcilable negative surcharge mechanism in order to refund to customers the net effect of the Tax Act for the period July 1, 2018, through December 31, 2018, to be prospectively updated for new rates effective January 1, 2019. The Pennsylvania Companies were also directed to establish a regulatory liability for the net impact of the Tax Act for the period of January 1, 2018 through June 30, 2018. On June 14, 2018, the PPUC issued an order revising this directive such that the Pennsylvania Companies must instead establish accounts to track tax savings for the period January 1, 2018, through March 14, 2018, and record regulatory liabilities associated with tax savings for only the period March 15, 2018 through June 30, 2018. The cumulative value of the tracked amounts and the regulatory liability is expected to amount to $12 million for ME, $13 million for PN, $3 million for Penn, and $10 million for WP. These amounts are expected to be addressed in the Pennsylvania Companies' next available rate proceedings, or independent filings to be made within three years, whichever comes sooner. The Pennsylvania Companies filed voluntary surcharges on June1, 2018, to adjust rates for the reduced tax rate, which were effective for bills rendered starting July 1, 2018. For the first six-month period, the surcharge is expected to return to customers $19 million for ME, $20 million for PN, $5 million for Penn, and $15 million for WP.

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.

On September 23, 2016, the WVPSC approved the Phase II energy efficiency program for MP and PE as reflected in a unanimous settlement, which includes three energy efficiency programs to meet the Phase II requirement of energy efficiency reductions of 0.5% of 2013 distribution sales for the January 1, 2017 through May 31, 2018 period, which was approved by the WVPSC in the 2012 proceeding approving the transfer of ownership of Harrison Power Station to MP. The costs for the Phase II program are expected to be $10.4 million and are eligible for recovery through the existing energy efficiency rider which is reviewed in the fuel (ENEC) case each year. On December 15, 2017, the WVPSC approved MP's and PE's proposed annual decrease in their EE&C rates, effective January 1, 2018, which decrease is not material to FirstEnergy. This Phase II energy efficiency program ended May 31, 2018.

On December 9, 2016, the WVPSC approved the annual ENEC case for MP and PE as reflected in a unanimous settlement, resulting in an increase in the ENEC rate of $25 million annually beginning January 1, 2017. In addition, ENEC rates will be maintained at the same level for a two-year period. The next ENEC filing is expected to be made by September 1, 2018.

On January 3, 2018, the WVPSC initiated a proceeding to investigate the effects of the Tax Act on the revenue requirements of utilities. MP and PE must track the tax savings resulting from the Tax Act on a monthly basis, effective January 1, 2018. On January 26, 2018, the WVPSC issued an order clarifying that regulatory accounting should be implemented as of January 1, 2018, including the recording of any regulatory liabilities resulting from the Tax Act. MP and PE filed written testimony on May 30, 2018, explaining the impact of the Tax Act on federal income tax and revenue requirements and showing an annual rate impact of $26.2 million. Other parties' testimony was filed on July 2, 2018 and MP and PE filed their rebuttal testimony on July 13, 2018. The WVPSC held evidentiary hearings on July 24-25, 2018.

FERC MATTERS

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, AE Supply, ATSI, MAIT 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, or obligations to upgrade or build transmission facilities, that could have a material adverse effect on its financial condition, results of operations and cash flows.

PJM Transmission Rates

PJM and its stakeholders have been debating the proper method to allocate costs for a certain class of new transmission facilities since 2005. 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. For historical transmission costs prior to January 1, 2016, the settlement agreement provides a “black-box” schedule of credits to and payments from customers across PJM’s transmission zones. From January 1, 2016 forward, PJM will collect a charge for the revenue requirement associated with each transmission enhancement through a “50/50” calculation, with 50% based on a load-ratio share and the other 50% solution-based distribution factor (DFAX) hybrid method. On May 31, 2018, FERC approved the settlement agreement as filed, without conditions. As a result of the settlement, FirstEnergy recorded a pre-tax benefit of approximately $77 million (within the Other operating expenses line on the Consolidated Statement of Income) relating to the amount of refund the Ohio Companies will receive and retain from PJM for the period prior to January 1, 2016. For the period after January 1, 2016, FirstEnergy is currently unable to reasonably estimate the impact until PJM releases the “50/50” allocation factors and FirstEnergy calculates the respective charges and credits. PJM is expected to implement the settlement for transmission service purchased in July 2018 in customer bills beginning in August 2018. Requests for rehearing or clarification of FERC's May 31, 2018, orders and related responses remain pending before FERC.

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, FirstEnergy joined certain other PJM TOs in a protest of MISO's proposal to allocate MVP costs to energy transactions that cross MISO's borders into the PJM Region. On July 13, 2016, FERC issued its order finding it appropriate for MISO to assess an MVP usage charge for transmission exports from MISO to PJM. Various parties, including FirstEnergy and the PJM TOs, requested rehearing or clarification of FERC’s order. The requests for rehearing remain pending before FERC.

In addition, in a May 31, 2011 order, FERC ruled that the costs for certain "legacy RTEP" transmission projects in PJM approved before ATSI joined PJM could be charged to transmission customers in the ATSI zone. The amount to be paid, and the question of derived benefits, will be determined pursuant to the settlement agreement described above under "PJM Transmission Rates."

The outcome of the proceedings that address the remaining open issues related to MVP costs cannot be predicted at this time.

MAIT Transmission Formula Rate

On October 28, 2016, as amended on January 10, 2017, MAIT submitted an application to FERC requesting authorization to implement a forward-looking formula transmission rate to recover and earn a return on transmission assets effective February 1, 2017. Various intervenors submitted protests of the proposed MAIT formula rate. Among other things, the protests asked FERC to suspend the proposed effective date for the formula rate until June 1, 2017. On March 10, 2017, FERC issued an order accepting the MAIT formula transmission rate for filing, suspending the formula transmission rate for five months to become effective July 1, 2017, and establishing hearing and settlement judge procedures. On April 10, 2017, MAIT requested rehearing of FERC’s decision to suspend the effective date of the formula rate. MAIT’s rates went into effect on July 1, 2017, subject to refund pending the outcome of the hearing and settlement procedures. On October 13, 2017, MAIT and certain parties filed a settlement agreement with FERC. The settlement agreement provides for certain changes to MAIT's formula rate, changes MAIT's ROE from 11% to 10.3%, sets the recovery amount for certain regulatory assets, and establishes that MAIT's capital structure will not exceed 60% equity over the period ending December 31, 2021. The settlement agreement further provides that the ROE and the 60% cap on the equity component of MAIT's capital structure will remain in effect unless changed pursuant to section 205 or 206 of the FPA provided the effective date for any change shall be no earlier than January 1, 2022.

On May 21, 2018, FERC issued an order accepting the settlement agreement as filed, without conditions. Refunds for the difference between the filed rate and the settlement rate will be handled through MAIT's true-up process. In compliance with the settlement agreement, on June 15, 2018, MAIT withdrew its April 2017 request for rehearing of FERC’s March 10, 2017 order.

PATH Transmission Project

In 2012, the PJM Board of Managers canceled the PATH project, a proposed transmission line from West Virginia through Virginia and into Maryland. 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 hearing and settlement procedures. On January 19, 2017, FERC issued an order reducing the PATH formula rate ROE from 10.4% to 8.11% effective January 19, 2017 and allowing recovery of certain related costs. On February 21, 2017, PATH filed a request for rehearing with FERC seeking recovery of disallowed costs and requesting that the ROE be reset to 10.4%. The Edison Electric Institute submitted an amicus curiae request for reconsideration in support of PATH. On March 20, 2017, PATH also submitted a compliance filing implementing the January 19, 2017 order. Certain affected ratepayers challenged the compliance filing, and FERC Staff requested additional information on, and edits to, the compliance filing, as directed by the January 19, 2017 order. PATH responded to comments and Staff’s request. FERC orders on PATH's requests for rehearing and compliance filing remain pending.

FERC Actions on Tax Act

On March 15, 2018, FERC took action to address the impact of the Tax Act on FERC-jurisdictional rates, including transmission and electric wholesale rates. FERC directed MP, PE and WP to either submit a joint filing to adjust the transmission rate for the Allegheny transmission zone in the PJM Region to address the impact of the Tax Act changes, or to “show cause” as to why such action is not required. FERC established a refund effective date of March 21, 2018 for any refunds as a result of the change in tax rate. On May 14, 2018, MP, PE and WP submitted revisions to their stated transmission rate to reflect the reduction in the federal corporate income tax rate. The revisions reduce the rate by 6.70%. There were no comments submitted in response to the proposed revisions, and the matter is now before FERC for further action. FERC is not at this time requiring other FirstEnergy FERC-jurisdictional companies to make changes to their transmission or wholesale rates. However, these rates may be affected by a related FERC "Notice of Inquiry" assessing the impact of the Tax Act on certain rate components.

Also, on March 15, 2018, FERC issued a Notice of Inquiry seeking information regarding whether and how FERC should address possible changes to accumulated deferred income taxes and bonus depreciation as a result of the Tax Act. Such possible changes could impact FERC-jurisdictional rates, including wholesale rates. Various entities submitted responses to the Notice of Inquiry on May 21, 2018. FESC, on behalf of its transmission owning affiliates, participated in the development of separate comments submitted by Edison Electric Institute and certain PJM TOs. The matter is now before FERC for further action.

PJM Markets: Grid Reliability and Resiliency

On September 28, 2017, the Secretary of Energy released a NOPR requesting FERC to issue rules directing RTOs, including PJM, to incorporate pricing for defined “eligible grid reliability and resiliency resources” into wholesale energy markets. FERC established a docket requesting comments, and issued an order on January 8, 2018 terminating the NOPR proceeding, finding that the NOPR did not satisfy the statutory threshold requirements under the FPA for requiring changes to RTO/ISO tariffs to address resilience concerns. FERC in its order instituted a new administrative proceeding to gather additional information regarding resilience issues. Each RTO/ISO responded to a provided list of questions and various entities submitted comments. The matter is now before FERC for further action. In the event FERC orders resiliency payments in wholesale energy markets, such charges may be levied against LSEs in the PJM Region, including the Utilities. There is no deadline or requirement for FERC to act in this new proceeding and as such the outcome of the proceeding and its impact on the Utilities, if any, cannot be predicted at this time.

PJM Markets: Capacity Pricing Reform

In March 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 PJM capacity markets by state-subsidized generation. However, FERC took no action at that time.

In April 2018, PJM filed with FERC two alternative proposals to modify the PJM Tariff to address concerns that state-authorized subsidies to certain generators within PJM may affect market prices. Under one approach, PJM would establish a two-stage capacity auction to enable subsidized generators to participate in the auction, but to prevent the subsidies from affecting the market clearing price. Under the alternative approach, the MOPR would be expanded to cover all generators in PJM, including vertically-integrated utility generation owners such as MP and JCP&L. PJM requested FERC action on the filing by June 29, 2018, and to make the proposed tariff revisions effective as of January 4, 2019. FESC, on behalf of its affiliates and jointly with EKPC, submitted a protest of PJM's proposals. FESC and EKPC requested FERC reject PJM's proposals, maintain the existing PJM market rules, and direct PJM to develop a holistic solution to the fundamental issues facing its markets. FESC and EKPC submitted that should FERC opt to change PJM's existing MOPR rules, FERC should accept PJM's capacity repricing option subject to additional development pursuant to PJM's stakeholder process. Various other entities also submitted protests and comments.

On June 29, 2018, FERC issued an order rejecting the March 2016 complaint and both of PJM's April 2018 proposals, finding that none of the proposed solutions to MOPR reform were just and reasonable and not unduly discriminatory. FERC established a new FPA Section 206 proceeding to develop a solution to the MOPR construct. FERC's directives in the new proceeding are to revise the MOPR so that it (i) applies to both existing and new resources that receive out-of-market subsidies with very limited exemptions; and (ii) accommodates state policies by allowing a new FRR-like alternative that would remove resources that receive out-of-market subsidies from the capacity market if the unit could be paired with a commensurate amount of load. Resources receiving out-of-market revenues could opt to stay in the capacity market but would be subject to the revised MOPR, or under the FRR-like alternative they could exit the market. FERC established a timeline for comments and expects to issue an order by January 4, 2019, so that the reformed MOPR can be implemented for the 2019 BRA. FERC instituted a refund effective date of July 11, 2018, for the new Section 206 proceeding. On July 30, 2018 FESC, on behalf of the Utilities, submitted a request for clarification or, in the alternative, rehearing of FERC's June 29, 2018 order. Specifically, FESC requested clarification regarding the applicability of FERC's directed MOPR reform to vertically-integrated resources.

On May 31, 2018, certain merchant generators filed a complaint with FERC against PJM seeking an order finding that PJM's existing MOPR mechanism is unjust and unreasonable, and implementing instead a so-called "Clean" MOPR that would apply to existing and new generation resources of all fuel types and all ownership arrangements, including regulated generation resources such as MP's and JCP&L's existing generation, that receive or have any form of "out-of-market" support, including recovery of generation costs in retail rates. The complainants request a FERC order by May 2019, so that the proposed "Clean" MOPR could be implemented in PJM's 2019 BRA. PJM answered the complaint on June 19, 2018, requesting that FERC accept one of PJM's two proposed alternatives (discussed above) instead. FESC, on behalf of its affiliates and jointly with EKPC, submitted a protest of the complaint. FESC and

EKPC requested FER reject PJM's proposals, maintain the existing PJM market rules, and direct PJM to develop a holistic solution to the fundamental issues facing its market. FESC and EKPC submitted that should FERC opt to change PJM's existing MOPR rules, FERC should accept PJM's capacity repricing option subject to additional development pursuant to PJM's stakeholder process. Various other entities also submitted protests and comments. FERC did not address the Clean MOPR Complaint in its June 29, 2018 order and, in consequence, the Clean MOPR Complaint remains pending before FERC. The outcome of FERC's Section 206 proceeding and the Clean MOPR Complaint, and their impact on FirstEnergy's regulated generation sources, if any, cannot be predicted at this time.

14. 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, 2018, FirstEnergy's outstanding guarantees and other assurances aggregated approximately $1.7 billion, consisting of guarantees and assurances on behalf of FES and FENOC ($354 million), parental guarantees on behalf of its consolidated subsidiaries ($1 billion), other guarantees ($235 million) and other assurances ($128 million).

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 ratings 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 AE Supply's power portfolio exposure as of June 30, 2018, AE Supply has posted collateral of $2 million. The Utilities and FET have posted collateral of $10 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. The following table discloses the potential additional credit rating contingent contractual collateral obligations as of June 30, 2018.

Potential Collateral Obligations	AE Supply	Utilities and FET	FE	Total
	(In millions)			
Contractual Obligations for Additional Collateral				
At Current Credit Rating	$ 1	$ —	$—	$1
Upon Further Downgrade	—	56	—	56
Surety Bonds (Collateralized Amount)	1	59	235	295
Total Exposure from Contractual Obligations	$ 2	$ 115	$235	$352

Surety Bonds are not tied to a credit rating. Surety Bonds' impact assumes maximum contractual obligations (typical obligations require 30 days to cure). FE provides credit support for FG surety bonds of $169 million and $31 million for the benefit of the PA DEP with respect to LBR CCR impoundment closure and post-closure activities and the Hatfield's Ferry CCR disposal site, respectively.

OTHER COMMITMENTS AND CONTINGENCIES

FE is a guarantor under a $300 million syndicated senior secured term loan facility due March 3, 2020, under which Global Holding's outstanding balance is $235 million as of June 30, 2018. 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 guarantees 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. Pursuant to a March 28, 2017 executive order, the EPA and other federal agencies are to review existing regulations that potentially burden the development or use of domestically produced energy resources and appropriately suspend, revise or rescind those that unduly burden the development of domestic energy resources beyond the degree necessary to protect the public interest or otherwise comply with the law. FirstEnergy cannot predict the timing or ultimate outcome of any of these reviews or how any future actions taken as a result thereof, in particular with respect to existing environmental regulations, may impact its business, results of operations, cash flows and financial condition.

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 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 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 the EPA’s regulatory approach under CSAPR, but questioning whether the EPA required upwind states to reduce emissions by more than their contribution to air pollution in downwind states. The EPA issued a CSAPR update rule on September 7, 2016, reducing summertime NOx emissions from power plants in 22 states in the eastern U.S., including Ohio, Pennsylvania and West Virginia, beginning in 2017. Various states and other stakeholders appealed the CSAPR update rule to the D.C. Circuit in November and December 2016. On September 6, 2017, the D.C. Circuit rejected the industry's bid for a lengthy pause in the litigation and set a briefing schedule. Depending on the outcome of the appeals, the EPA’s reconsideration of the CSAPR update rule and how the EPA and the states ultimately implement CSAPR, the future cost of compliance may be material and changes to FirstEnergy's operations may result.

The EPA tightened the primary and secondary NAAQS for ozone from the 2008 standard levels of 75 PPB to 70 PPB on October 1, 2015. The 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 on April 30, 2018, the EPA designated fifty-one areas in twenty-two states as non-attainment; however, FirstEnergy has no power plants operating in those areas. States 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 operations may result. In August 2016, the State of Delaware filed a CAA Section 126 petition with the EPA alleging that the Harrison generating facility's NOx emissions significantly contribute to Delaware's inability to attain the ozone NAAQS. The petition seeks a short-term NOx emission rate limit of 0.125 lb/mmBTU over an averaging period of no more than 24 hours. On September 27, 2016, the EPA extended the time frame for acting on the State of Delaware's CAA Section 126 petition by six months to April 7, 2017, but has not taken any further action. On January 2, 2018, the State of Delaware provided the EPA a notice required at least 60 days prior to filing a suit seeking to compel the EPA to either approve or deny the August 2016 CAA Section 126 petition. In November 2016, the State of Maryland filed a CAA Section 126 petition with the EPA alleging that NOx emissions from 36 EGUs, including Harrison Units 1, 2 and 3 and Pleasants Units 1 and 2, significantly contribute to Maryland's inability to attain the ozone NAAQS. The petition seeks NOx emission rate limits for the 36 EGUs by May 1, 2017. On January 3, 2017, the EPA extended the time frame for acting on the CAA Section 126 petition by six months to July 15, 2017, but has not taken any further action. On September 27, 2017, and October 4, 2017, the State of Maryland and various environmental organizations filed complaints in the U.S. District Court for the District of Maryland seeking an order that the EPA either approve or deny the CAA Section 126 petition of November 16, 2016. On May 31, 2018, the EPA proposed to deny both the States of Delaware and Maryland petitions under CAA Section 126. In March 2018, the State of New York filed a CAA Section 126 petition with the EPA alleging that NOx emissions from nine states (including Ohio, Pennsylvania and West Virginia) significantly contribute to New York’s inability to attain the ozone NAAQS. The petition seeks suitable emission rate limits for large stationary sources that are affecting New York’s air quality within the three years allowed by CAA Section 126. On May 3, 2018, the EPA extended the time frame for acting on the CAA Section 126 petition by six months to November 9, 2018. FirstEnergy is unable to predict the outcome of these matters or estimate the loss or range of loss.

On May 1, 2017, FE and FG and CSX and BNSF entered into a definitive settlement agreement, which resolved all claims related to a coal transportation contract dispute as a result of MATS on the terms and conditions set forth below. Pursuant to the settlement agreement, FG agreed to pay CSX and BNSF an aggregate amount equal to $109 million, payable in three annual installments, the first of which was made on May 1, 2017. FE agreed to unconditionally and continually guarantee the settlement payments due by FG pursuant to the terms of the settlement agreement. The settlement agreement further provided that in the event of the initiation of bankruptcy proceedings or failure to make timely settlement payments, the unpaid settlement amount will immediately accelerate and become due and payable in full. On April 6, 2018, FE paid the remaining $72 million under the settlement agreement as a result of the FES Bankruptcy.

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. On June 23, 2014, the U.S. Supreme Court decided that CO_2 or other GHG emissions alone cannot trigger permitting requirements under the CAA, but that air emission sources that need PSD permits due to other regulated air pollutants can be required by the EPA to install GHG control technologies. The EPA released its final CPP regulations in August 2015 (which have been stayed by the U.S. Supreme Court), to reduce CO_2 emissions from existing fossil fuel-fired EGUs. The EPA also finalized separate regulations imposing CO_2 emission limits for new, modified, and reconstructed fossil fuel fired EGUs. Numerous states and private parties filed appeals and motions to stay the CPP with the D.C. Circuit in October 2015. On January 21, 2016, 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. On March 28, 2017, an executive order, entitled “Promoting Energy Independence and Economic Growth,” instructed the EPA to review the CPP and related rules addressing GHG emissions and suspend, revise or rescind the rules if appropriate. On October 16, 2017, the EPA issued a proposed rule to repeal the CPP. Depending on the outcomes of the review pursuant to the executive order, 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 GHG emissions by 26 to 28 percent below 2005 levels by 2025, and in September 2016, joined in adopting the agreement reached on December 12, 2015, at the United Nations Framework Convention on Climate Change meetings in Paris. The Paris Agreement was ratified by the requisite number of countries (i.e., at least 55 countries representing at least 55% of global GHG emissions) in October 2016 and its non-binding obligations to limit global warming to well below two degrees Celsius became effective on November 4, 2016. On June 1, 2017, the Trump Administration announced that the U.S. would cease all participation in the Paris Agreement. 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.

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 facilities. 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. Depending on any final action taken by the states with respect to impingement and entrainment, the future capital costs of compliance with these standards may be material.

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 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. On April 13, 2017, the EPA granted a Petition for Reconsideration and administratively stayed (effective upon publication in the Federal Register) all deadlines in the effluent limits rule pending a new rulemaking. Also, on September 18, 2017, the EPA postponed certain compliance deadlines for two years. 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 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. In March 2018, the WVDEP issued a draft NPDES Permit Renewal that, if finalized as proposed, would moot the appeal and reduce the estimated capital investment requirements. 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 CCRs, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation.

In April 2015, the EPA finalized regulations for the disposal of CCRs (non-hazardous), establishing national standards for 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. On September 13, 2017, the EPA announced that it would reconsider certain provisions of the final regulations. On July 17, 2018, the EPA Administrator signed a final rule extending the deadline for certain CCR facilities to cease disposal and commence closure activities, as well as, establishing less stringent groundwater monitoring and protection requirements. Based on an assessment of the finalized regulations, the future cost of compliance and expected timing had no significant impact on FirstEnergy's existing AROs associated with CCRs. Although not currently expected, changes in timing and closure plan requirements in the future could materially and adversely impact FirstEnergy's AROs.

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, 2018, based on estimates of the total costs of cleanup, FirstEnergy's proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $116 million have been accrued through June 30, 2018. Included in the total are accrued liabilities of approximately $78 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. FE 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, JCP&L, ME and PN must ensure that adequate funds will be available to decommission their retired nuclear facility, TMI-2. As of June 30, 2018, JCP&L, ME and PN had approximately $0.8 billion invested in external trusts to be used for the decommissioning and environmental remediation of their retired TMI-2 nuclear generating facility. The values of these NDTs also fluctuate based on market conditions. If the values of the trusts decline by a material amount, the obligation of JCP&L, ME, and PN 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.

FES Bankruptcy

On March 31, 2018, FES, including its consolidated subsidiaries, FG, NG, FE Aircraft Leasing Corp., Norton Energy Storage L.L.C. and FirstEnergy Generation Mansfield Unit 1 Corp, and FENOC filed voluntary petitions for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code in the Bankruptcy Court. See Note 3, "Discontinued Operations," for additional information.

Other Legal Matters

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to FirstEnergy's normal business operations pending against FE or its subsidiaries. The loss or range of loss in these matters is not expected to be material to FE or its subsidiaries. The other potentially material items not otherwise discussed above are described under Note 13, "Regulatory Matters."

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 FE 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 FE's or its subsidiaries' financial condition, results of operations and cash flows.

15. SEGMENT INFORMATION

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

On March 31, 2018, as discussed in Note 3, “Discontinued Operations,” FirstEnergy deconsolidated FES and FENOC and presented FES, FENOC, BSPC and a portion of AE Supply, representing substantially all of FirstEnergy’s operations that previously comprised the CES reportable operating segment, as discontinued operations in FirstEnergy’s consolidated financial statements resulting from actions taken as part of the strategic review to exit commodity-exposed generation. The financial information for all periods has been revised to present the discontinued operations within Reconciling Adjustments. The remaining business activities that previously comprised the CES reportable operating segment were not material and, as such, have been combined into Corporate/Other for reporting purposes.

The Regulated Distribution segment distributes electricity through FirstEnergy’s ten utility operating companies, serving approximately six million customers within 65,000 square miles of Ohio, Pennsylvania, West Virginia, Maryland, New Jersey and New York, and purchases power for its POLR, SOS, SSO and default service requirements in Ohio, Pennsylvania, New Jersey and Maryland. This segment also controls 3,790 MWs of regulated electric generation capacity located primarily in West Virginia, Virginia and New Jersey. The segment's results reflect the commodity costs of securing electric generation and the deferral and amortization of certain fuel costs.

The Regulated Transmission segment provides transmission infrastructure owned and operated by ATSI, TrAIL, MAIT and certain of FirstEnergy's utilities (JCP&L, MP, PE and WP) to transmit electricity from generation sources to distribution facilities. The segment's revenues are primarily derived from forward-looking formula rates at ATSI, TrAIL, and MAIT as well as stated transmission rates at JCP&L, MP, PE and WP. Both the forward-looking formula and stated rates recover costs that the regulatory agencies determine are permitted to be recovered and provide a return on transmission capital investment. Under forward-looking formula rates, the revenue requirement is updated annually based on a projected rate base and projected costs, which is subject to an annual true-up based on actual costs. The segment's results also reflect the net transmission expenses related to the delivery of electricity on FirstEnergy's transmission facilities.

Corporate support not charged to FE's subsidiaries, interest expense on stand-alone holding company debt, corporate income taxes and other businesses that do not constitute an operating segment are categorized as Corporate/Other for reportable business segment purposes. Additionally, reconciling adjustments for the elimination of inter-segment transactions and discontinued operations are included in Corporate/Other. As of June 30, 2018, 1,367 MWs of electric generating capacity, representing the Pleasants Plant and AE Supply's OVEC capacity entitlement, was included in Corporate/Other. As of June 30, 2018, Corporate/Other had $5.35 billion of FE holding company long-term debt and $1.6 billion in borrowings under its revolving credit facility.

Financial information for each of FirstEnergy's reportable segments is presented in the tables below.

Segment Financial Information

For the Three Months Ended	Regulated Distribution	Regulated Transmission	Corporate/ Other	Reconciling Adjustments	Consolidated
	(In millions)				
June 30, 2018					
Revenues	$2,352	$ 341	$ 86	$ (75)	$ 2,704
Depreciation	200	62	19	18	299
Deferral of regulatory assets, net	(107)	—	—	—	(107)
Miscellaneous income (expense), net	56	3	(1)	(10)	48
Interest expense	129	42	208	(10)	369
Income taxes	138	38	(61)	—	115
Income (loss) from continuing operations	377	104	(214)	—	267
Total assets	28,088	9,833	1,050	—	38,971
Total goodwill	5,004	614	—	—	5,618
Property additions	391	282	51	—	724
June 30, 2017					
Revenues	$2,271	$ 327	$ 77	$ (51)	$ 2,624
Depreciation	179	54	3	18	254
Amortization of regulatory assets, net	75	3	—	—	78
Miscellaneous income (expense), net	14	—	10	(13)	11
Interest expense	134	39	88	(13)	248
Income taxes (benefits)	121	53	(42)	—	132
Income (loss) from continuing operations	205	92	(78)	—	219
Total assets	27,660	9,142	1,190	5,335	43,327
Total goodwill	5,004	614	—	—	5,618
Property additions	304	245	29	88	666
For the Six Months Ended					
June 30, 2018					
Revenues	$4,928	$ 664	$ 211	$ (123)	$ 5,680
Depreciation	396	123	38	36	593
Amortization (deferral) of regulatory assets, net	(259)	4	—	—	(255)
Miscellaneous income (expense), net	112	7	15	(19)	115
Interest expense	257	81	300	(19)	619
Income taxes	231	70	66	—	367
Income (loss) from continuing operations	699	203	(458)	—	444
Property additions	655	574	63	15	1,307
June 30, 2017					
Revenues	$4,771	$ 640	$ 169	$ (101)	$ 5,479
Depreciation	357	105	7	35	504
Amortization of regulatory assets, net	156	5	—	—	161
Miscellaneous income (expense), net	29	—	16	(20)	25
Interest expense	272	78	163	(20)	493
Income taxes (benefits)	259	105	(80)	—	284

Income (loss) from continuing operations	442	180	(146)	—	476
Property additions	568	469	39	178	1,254

ITEM 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations

FIRSTENERGY CORP.
MANAGEMENT’S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS
FIRSTENERGY’S BUSINESS

FE and its subsidiaries are principally involved in the transmission, distribution and generation of electricity. Its reportable segments are as follows: Regulated Distribution and Regulated Transmission.

On March 31, 2018, as discussed below, FirstEnergy deconsolidated FES and FENOC and presented FES, FENOC, BSPC and a portion of AE Supply, representing substantially all of FirstEnergy’s operations that previously comprised the CES reportable operating segment, as discontinued operations in FirstEnergy’s consolidated financial statements resulting from actions taken as part of the strategic review to exit commodity-exposed generation. The financial information for all periods has been revised to present the discontinued operations within Reconciling Adjustments. The remaining business activities that previously comprised the CES reportable operating segment were not material and, as such, have been combined into Corporate/Other for reporting purposes.

The Regulated Distribution segment distributes electricity through FirstEnergy’s ten utility operating companies, serving approximately six million customers within 65,000 square miles of Ohio, Pennsylvania, West Virginia, Maryland, New Jersey and New York, and purchases power for its POLR, SOS, SSO and default service requirements in Ohio, Pennsylvania, New Jersey and Maryland. This segment also controls 3,790 MWs of regulated electric generation capacity located primarily in West Virginia, Virginia and New Jersey. The segment's results reflect the commodity costs of securing electric generation and the deferral and amortization of certain fuel costs.

The Regulated Transmission segment provides transmission infrastructure owned and operated by ATSI, TrAIL, MAIT and certain of FirstEnergy's utilities (JCP&L, MP, PE and WP) to transmit electricity from generation sources to distribution facilities. The segment's revenues are primarily derived from forward-looking formula rates at ATSI, TrAIL, and MAIT as well as stated transmission rates at certain of JCP&L, MP, PE and WP. Both the forward-looking formula and stated rates recover costs that the regulatory agencies determine are permitted to be recovered and provide a return on transmission capital investment. Under forward-looking formula rates, the revenue requirement is updated annually based on a projected rate base and projected costs, which is subject to an annual true-up based on actual costs. The segment's results also reflect the net transmission expenses related to the delivery of electricity on FirstEnergy's transmission facilities.

Corporate support not charged to FE's subsidiaries, interest expense on stand-alone holding company debt, corporate income taxes and other businesses that do not constitute an operating segment are categorized as Corporate/Other for reportable business segment purposes. Additionally, reconciling adjustments for the elimination of inter-segment transactions and discontinued operations are included in Corporate/Other. As of June 30, 2018, 1,367 MWs of electric generating capacity, representing the Pleasants Plant and AE Supply's OVEC capacity entitlement, was included in Corporate/Other. As of June 30, 2018, Corporate/Other had $5.35 billion of FE holding company long-term debt and $1.6 billion in borrowings under its revolving credit facility.

EXECUTIVE SUMMARY

FirstEnergy’s strategy is to be a fully regulated utility company, focusing on stable and predictable earnings and cash flow from its regulated business units - Regulated Distribution and Regulated Transmission - which focus on delivering enhanced customer service and reliability. Together, the Regulated Distribution and Regulated Transmission businesses are expected to provide stable, predictable earnings and cash flows that support FE’s dividend.

The scale and diversity of the ten Utilities that comprise the Regulated Distribution business uniquely position this business for growth through opportunities for additional investment. Since 2015, Regulated Distribution has experienced significant growth through investments that have improved reliability and added operating flexibility to the distribution infrastructure, which provide benefits to the customers and communities those Utilities serve. Based on its current capital plan, which includes $5.7 to $6.7 billion in forecasted capital investments through 2021, Regulated Distribution’s rate base growth rate is expected to be approximately 5% through 2021. Additionally, this business is exploring other opportunities for growth, including investments in electric system improvement and modernization projects to increase reliability and improve service to customers, as well as exploring opportunities in customer engagement that focus on the electrification of customers' homes and businesses by providing a full range of products and services.

With approximately 24,500 miles in operations, the Regulated Transmission business is the centerpiece of FirstEnergy’s regulated investment strategy with approximately 80% of its capital investments recovered under forward-looking formula rates, including ATSI, TrAIL, and MAIT. Regulated Transmission has also experienced significant growth as part of its Energizing the Future transmission plan with plans to invest $4.0 to $4.8 billion in capital from 2018 to 2021, which is expected to result in Regulated Transmission rate base growth of approximately 11% through 2021.

FirstEnergy believes there are incremental investment opportunities for its existing transmission infrastructure of approximately $20 billion beyond those identified through 2021, which are expected to strengthen grid and cyber-security and make the transmission system more reliable, robust, secure and resistant to extreme weather events, with improved operational flexibility.

On December 22, 2017, the President signed the Tax Act into law. Substantially all of the provisions of the Tax Act are effective for taxable years beginning after December 31, 2017. As discussed below, various state regulatory proceedings have been initiated to investigate the impact of the Tax Act on the Utilities’ rates and charges, and FERC recently took action to address the impact of the Tax Act on FERC-jurisdictional rates, including transmission and electric wholesale rates. FirstEnergy continues to work with various state regulatory commissions to determine appropriate changes to customer rates resulting from the Tax Act. Several states have since implemented rate reductions to reflect the impact of the Tax Act, while in the remaining states, FirstEnergy continues to track and apply regulatory accounting treatment for the expected rate impact of changes resulting from the Tax Act. FirstEnergy has also reflected the impact of changes to current taxes in its normal update to FERC-jurisdictional transmission rates and will continue to work with FERC regarding whether and how it should address possible changes to transmission and wholesale rates resulting from the Tax Act.

As previously disclosed, on January 22, 2018, FirstEnergy announced a $2.5 billion equity issuance, which included $1.62 billion in mandatorily convertible preferred equity with an initial conversion price of $27.42 per share and $850 million of common equity issued at $28.22 per share. The preferred shares participate in the dividend paid on common stock on an as-converted basis and are non-voting except in certain limited circumstances. The preferred shares contain an optional conversion right for holders as of July 22, 2018, and will mandatorily convert in July 2019, subject to limited exceptions. Proceeds from the investment were used to reduce holding company debt by

$1.45 billion and fund the company's pension plan by $750 million, with the remainder used for general corporate purposes. Because of this investment, FirstEnergy does not currently anticipate the need to issue additional equity through at least 2021 outside of its regular stock investment and employee benefit plans. As of July 27, 2018, 224,714 shares of preferred stock have been converted to 8,195,257 shares of common stock at the option of the holders.

The equity investment strengthened the Company's balance sheet and positions FirstEnergy for sustained investment-grade credit metrics. In connection with the equity investment, FirstEnergy formed a RWG composed of three employees of FirstEnergy and two outside members to advise FirstEnergy management regarding the FES Bankruptcy. The RWG has been engaged in substantive negotiations with a steering committee of FES noteholders further discussed below.

On March 31, 2018, FirstEnergy's competitive subsidiary FES and FENOC voluntarily filed petitions under Chapter 11 of the Federal Bankruptcy Code with the U.S. Bankruptcy Court. FirstEnergy and its other subsidiaries - including its Utilities and AE Supply - are not part of the filing and will not be subject to the Chapter 11 process. The voluntary bankruptcy filings by FES and FENOC represent a significant event in FirstEnergy's previously announced strategy to exit the competitive generation business and become a fully regulated utility company with a stronger balance sheet, solid cash flows and more predictable earnings. As a result of the bankruptcy filings, as of March 31, 2018, FES and FENOC were deconsolidated from FirstEnergy's financial statements. Additionally, the operating results of FES and FENOC, as well as BSPC and a portion of AE Supply that were subject to completed or pending asset sales, collectively representing substantially all of FirstEnergy's operations that comprised the CES reportable segment, are presented as discontinued operations. Prior periods have been reclassified to conform with such presentation as discontinued operations.

On April 20, 2018, FirstEnergy reached an agreement in principle with two groups of key FES creditors in the FES Bankruptcy. The first is an ad hoc group, which includes a majority of the pollution control revenue bonds supported by notes issued by FG and NG and the holders of senior notes issued by FES, while the second group includes the majority of Bruce Mansfield Unit 1 sale and leaseback transaction certificate holders. On May 7, 2018, FE, FES, the FES ad hoc creditor groups and the UCC entered into a Standstill Agreement, which was previously approved by the Bankruptcy Court, agreeing to keep the terms of the settlement open through August 1, 2018, and to other matters to enable an efficient settlement process, including expedited discovery protocols and transfer restrictions on the FES creditor groups. On July 31, 2018, FirstEnergy reached an updated agreement in principle with the same two groups of key FES creditors in the FES Bankruptcy and added FES, FENOC, and the UCC to such agreement in principle. In connection with the agreement in principle, the parties also extended the Standstill Agreement until the earlier of the effective date of a plan of reorganization for FES and FENOC or termination of the definitive settlement agreement. The updated agreement in principle includes the following terms, among others:

- FE will pay certain pre-petition FES and FENOC employee-related obligations, which include unfunded pension obligations and other employee benefits, and provides for the waiver of all pre-petition claims against FES and FENOC, including the full borrowings by FES under the $500 million secured credit facility, the $200 million credit agreement being used to support surety bonds, the BNSF/CSX rail settlement guarantee, and FES' and FENOC's unfunded pension obligations.
- The full release of all claims against FirstEnergy by FES, FENOC and their creditors.
- A $225 million cash payment from FirstEnergy.
- Up to a $628 million note from FirstEnergy, which is intended to represent the initial estimated value of the worthless stock deduction associated with the FES Bankruptcy and was designed to trade at par value when issued.
- Transfer of the Pleasants Power Station to FES for the benefit of FES' creditors. Prior to transfer and beginning no later than January 1, 2019, FES to have an economic lease in Pleasants; AE Supply will operate Pleasants until transfer.
- FirstEnergy agrees to credit nine-months of FES' and FENOC's shared service costs beginning as of April 1, 2018, in an amount not to exceed $112.5 million, and FirstEnergy agrees to extend the availability of shared services until no later than June 30, 2020.
- FirstEnergy agrees to fund through its pension plan a pension enhancement should FES offer a voluntary enhanced retirement package in 2019, which is estimated to cost $15 million, and approximately $3 million for other employee benefits.

The timing of and the conditions to FirstEnergy's performance of the terms above are set forth in the agreement in principle. This agreement will be subject to approval by the FE, FES, FENOC and AE Supply Boards of Directors, the execution of definitive agreements and the approval of the Bankruptcy Court. Additionally, the Bruce Mansfield certificate holders' support for the agreement is subject to and conditioned upon the ultimate implementation of the agreed upon treatment of certain claims of the Bruce Mansfield certificate holders. There can be no assurance that a definitive settlement agreement will be finalized and approved and, even if approved, whether the conditions to such settlement will be satisfied, and the actual outcome of this matter may differ materially from the terms of the agreement in principle described herein.

With the bankruptcy filings of FES and FENOC, and the completed sale of the previously announced competitive Bath hydroelectric station, FirstEnergy's electric generation fleet is now made up of 3,790 MW of regulated generation, including four plants in West Virginia, Virginia and New Jersey. This excludes AE Supply's remaining competitive generation assets - the 1,300 MW Pleasants Power Station, which FirstEnergy has announced plans to sell or deactivate by the end of 2018, if not otherwise transferred to FES' creditors, and its 67 MW OVEC capacity entitlement.

In support of the strategic review to exit competitive generation, management launched the FE Tomorrow initiative to define FirstEnergy's future organization to support its regulated business. FE Tomorrow is intended to align corporate services to efficiently support the regulated operations by ensuring that FirstEnergy has the right talent, organizational and cost structure to achieve our earnings growth targets. In support of the FE Tomorrow initiative, in June and early July 2018, nearly 500 employees in the shared services and utility services and sustainability organizations, which was more than 80% of eligible employees, accepted a voluntary enhanced retirement package, which included severance compensation and a temporary pension enhancement, with most employees departing by December 31, 2018. FirstEnergy expects further talent, organizational and cost structure adjustments in order to accomplish the FE Tomorrow goals. Management expects the cost savings resulting from the FE Tomorrow initiative to support the company's growth targets.

FINANCIAL OVERVIEW AND RESULTS OF OPERATIONS

(In millions, except per share amounts)	For the Three Months Ended June 30,				For the Six Months Ended June 30,			
	2018	2017	Change		2018	2017	Change	
Revenues	$2,704	$2,624	$80	3 %	$5,680	$5,479	$201	4 %
Operating expenses	2,017	2,050	(33)	(2)%	4,396	4,277	119	3 %
Operating income	687	574	113	20 %	1,284	1,202	82	7 %
Other expenses, net	(305)	(223)	(82)	37 %	(473)	(442)	(31)	7 %
Income before income taxes	382	351	31	9 %	811	760	51	7 %
Income taxes	115	132	(17)	(13)%	367	284	83	29 %
Income from continuing operations	267	219	48	22 %	444	476	(32)	(7)%
Discontinued operations	32	(45)	77	NM	1,224	(97)	1,321	NM
Net income	$299	$174	$125	72 %	$1,668	$379	$1,289	340 %

* NM = not meaningful

The financial results discussed below include revenues and expenses from transactions among FirstEnergy’s business segments. A reconciliation of segment financial results is provided in Note 15, "Segment Information," of the Notes to Consolidated Financial Statements.

On March 31, 2018, as discussed above, FirstEnergy deconsolidated FES and FENOC and presented FES, FENOC, BSPC and a portion of AE Supply, representing substantially all of FirstEnergy’s operations that previously comprised the CES reportable operating segment, as discontinued operations in FirstEnergy’s consolidated financial statements resulting from the FES Bankruptcy and actions taken as part of the strategic review to exit commodity-exposed generation. The financial information for all periods has been revised to present the discontinued operations. The remaining business activities that previously comprised the CES reportable operating segment were not material and, as such, have been combined into Corporate/Other for reporting purposes.

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

Summary of Results of Operations — Second Quarter 2018 Compared with Second Quarter 2017

Financial results for FirstEnergy's business segments in the second quarter of 2018 and 2017 were as follows:

Second Quarter 2018 Financial Results	Regulated Distribution	Regulated Transmission	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)			
Revenues:				
External				
Electric	$2,291	$ 336	$ 31	$ 2,658
Other	61	5	(20)	46
Total Revenues	2,352	341	11	2,704
Operating Expenses:				
Fuel	128	—	49	177
Purchased power	699	—	(1)	698
Other operating expenses	666	60	(21)	705
Provision for depreciation	200	62	37	299
Deferral of regulatory assets, net	(107)	—	—	(107)
General taxes	184	48	13	245
Total Operating Expenses	1,770	170	77	2,017
Operating Income (Loss)	582	171	(66)	687
Other Income (Expense):				
Miscellaneous income (expense), net	56	3	(11)	48
Interest expense	(129)	(42)	(198)	(369)
Capitalized financing costs	6	10	—	16
Total Other Expense	(67)	(29)	(209)	(305)
Income (Loss) Before Income Taxes (Benefits)	515	142	(275)	382
Income taxes (benefits)	138	38	(61)	115
Income (Loss) From Continuing Operations	377	104	(214)	267
Discontinued Operations, net of tax	—	—	32	32
Net Income (Loss)	$377	$ 104	$ (182)	$ 299

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Second Quarter 2017 Financial Results	Regulated Distribution	Regulated Transmission	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)			
Revenues:				
External				
Electric	$2,206	$ 323	$ 32	$ 2,561
Other	65	4	(6)	63
Total Revenues	2,271	327	26	2,624
Operating Expenses:				
Fuel	121	—	42	163
Purchased power	646	—	4	650
Other operating expenses	634	50	(9)	675
Provision for depreciation	179	54	21	254
Amortization of regulatory assets, net	75	3	—	78
General taxes	175	43	12	230
Total Operating Expenses	1,830	150	70	2,050
Operating Income (Loss)	441	177	(44)	574
Other Income (Expense):				
Miscellaneous income (expense), net	14	—	(3)	11
Interest expense	(134)	(39)	(75)	(248)
Capitalized financing costs	5	7	2	14
Total Other Expense	(115)	(32)	(76)	(223)
Income (Loss) Before Income Taxes (Benefits)	326	145	(120)	351
Income taxes (benefits)	121	53	(42)	132
Income (Loss) From Continuing Operations	205	92	(78)	219
Discontinued Operations, net of tax	—	—	(45)	(45)
Net Income (Loss)	$205	$ 92	$ (123)	$ 174

Changes Between Second Quarter 2018 and Second Quarter 2017 Financial Results	Regulated Distribution	Regulated Transmission	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)			
Revenues:				
External				
Electric	$85	$ 13	$ (1)	$ 97
Other	(4)	1	(14)	(17)
Total Revenues	81	14	(15)	80
Operating Expenses:				
Fuel	7	—	7	14
Purchased power	53	—	(5)	48
Other operating expenses	32	10	(12)	30
Provision for depreciation	21	8	16	45
Amortization (deferral) of regulatory assets, net	(182)	(3)	—	(185)
General taxes	9	5	1	15
Total Operating Expenses	(60)	20	7	(33)
Operating Income (Loss)	141	(6)	(22)	113
Other Income (Expense):				
Miscellaneous income (expense), net	42	3	(8)	37
Interest expense	5	(3)	(123)	(121)
Capitalized financing costs	1	3	(2)	2
Total Other Expense	48	3	(133)	(82)
Income (Loss) Before Income Taxes (Benefits)	189	(3)	(155)	31
Income taxes (benefits)	17	(15)	(19)	(17)
Income (Loss) From Continuing Operations	172	12	(136)	48
Discontinued Operations, net of tax	—	—	77	77
Net Income (Loss)	$172	$ 12	$ (59)	$ 125

Regulated Distribution — Second Quarter 2018 Compared with Second Quarter 2017

Regulated Distribution's operating results increased $172 million in the second quarter of 2018, as compared to the same period of 2017, reflecting the reversal of a reserve on recoverability of certain REC purchases in Ohio, the net impact of a FERC settlement that reallocated certain transmission costs and higher revenues associated with increased weather-related usage.

Revenues —

The $81 million increase in total revenues resulted from the following sources:

Revenues by Type of Service	For the Three Months Ended June 30, 2018	2017	Increase (Decrease)
	(In millions)		
Distribution services[1]	$1,288	$1,255	$ 33
Generation sales:			
Retail	882	839	43
Wholesale	121	112	9
Total generation sales	1,003	951	52
Other	61	65	(4)
Total Revenues	$2,352	$2,271	$ 81

[1] Includes $60 million and $48 million of ARP revenues for the three months ended June 30, 2018 and 2017, respectively.

Distribution services revenues increased $33 million, primarily resulting from higher weather-related customer usage as described below. Additionally, distribution revenues were impacted by higher rates associated with the recovery of deferred costs, partially offset by certain tax impacts reflected as a reduction in revenues resulting from the Tax Act. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	For the Three Months Ended June 30, 2018	2017	Increase
	(In thousands)		
Residential	12,074	11,115	8.6 %
Commercial	10,197	10,039	1.6 %
Industrial	13,201	12,946	2.0 %
Other	140	138	1.4 %
Total Electric Distribution MWH Deliveries	35,612	34,238	4.0 %

Higher distribution deliveries to residential and commercial customers primarily reflect higher weather-related usage resulting from cooling degree days that were 22% above 2017, and 30% above normal and heating degree days that were 33% above 2017, and 5% above normal. Deliveries to industrial customers increased reflecting higher shale and steel customer usage.

The following table summarizes the price and volume factors contributing to the $52 million increase in generation revenues for the second quarter of 2018 compared to the same period of 2017:

Source of Change in Generation Revenues	Increase (Decrease) (In millions)
Retail:	
Effect of increase in sales volumes	$ 50
Change in prices	(7)
	43
Wholesale:	
Effect of decrease in sales volumes	(8)
Change in prices	11
Capacity Revenue	6
	9
Increase in Generation Revenues	$ 52

The increase in retail generation sales volumes was primarily due to higher weather-related usage, as described above. Total generation provided by alternative suppliers as a percentage of total MWH deliveries was flat across our service territory. The decrease in retail generation prices primarily resulted from lower default service auction prices in Pennsylvania and New Jersey.

Wholesale generation revenues increased $9 million in the second quarter of 2018, as compared to the same period in 2017, primarily due to higher spot market prices and capacity revenue, partially offset by lower 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 $60 million, primarily due to the following:

- Purchased power costs were $53 million higher in the second quarter of 2018, as compared to the same period in 2017, primarily due to increased volumes resulting from higher customer weather-related usage.

Source of Change in Purchased Power	Increase (Decrease) (In millions)
Purchases from non-affiliates:	
Change due to increased unit costs	$ 14
Change due to volumes	35
	49
Purchases from affiliates:	
Change due to decreased unit costs	(3)
Change due to volumes	(6)
	(9)
Capacity	13
Increase in Purchased Power Costs	$ 53

- Other operating expenses increased $32 million, primarily due to:
  - Increased storm restoration costs of $17 million, which were deferred for future recovery, resulting in no material impact on current period earnings.
  - Net network transmission expenses were flat reflecting increased transmission costs offset by a FERC settlement during the second quarter of 2018 that reallocated certain transmission costs across utilities in PJM and resulted in a refund to the Ohio Companies. Except for certain transmission costs and credits 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 operating and maintenance expenses of $15 million, primarily due to higher benefit costs.

- Depreciation expense increased $21 million, primarily due to a higher asset base.

- Amortization expense decreased $182 million, primarily due to the reversal of a liability at the Ohio Companies for an Ohio Supreme Court ruling regarding purchase of RECs, as well as higher deferrals of transmission expenses associated with the FERC settlement discussed above, and increased deferral of storm restoration costs.

Other Expense —

Total other expense decreased $48 million, primarily due to higher net miscellaneous income resulting from lower pension and OPEB non-service costs related to expected asset returns on the pension contributions discussed above, and lower capitalization, as well as lower interest expense resulting from a debt maturity at CEI.

Income Taxes —

Regulated Distribution’s effective tax rate was 26.8% and 37.1% for the three months ended June 30, 2018 and 2017, respectively. The lower rate is primarily a result of certain impacts of the Tax Act.

Regulated Transmission — Second Quarter 2018 Compared with Second Quarter 2017

Regulated Transmission's operating results increased $12 million in the second quarter of 2018, as compared to the same period of 2017, primarily resulting from the impact of a higher rate base at ATSI and MAIT and higher revenues at JCP&L, partially offset by a lower rate base at TrAIL.

Revenues —

Total revenues increased $14 million, primarily due to the implementation of approved settlement rates in JCP&L, effective January 1, 2018, recovery of incremental operating expenses and a higher rate base at ATSI and MAIT, partially offset by a lower rate base at TrAIL.

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

Revenues by Transmission Asset Owner	For the Three Months Ended June 30, 2018	2017	Increase (Decrease)
	(In millions)		
ATSI	$168	$164	$ 4
TrAIL	65	73	(8)

MAIT	35	24	11
Other	73	66	7
Total Revenues	$341	$327	$ 14

Operating Expenses —

Total operating expenses increased $20 million, primarily due to higher operating and maintenance expenses as well as higher property taxes and depreciation due to higher asset base. The majority of the increases were recovered through formula rates at ATSI, MAIT and TrAIL, resulting in no material impact on current period earnings.

Income Taxes —

Regulated Transmission's effective tax rate was 26.8% and 36.6% for the three months ended June 30, 2018 and 2017, respectively. The lower rate is primarily a result of certain impacts of the Tax Act.

Corporate / Other — Second Quarter 2018 Compared with Second Quarter 2017

Financial results from the Corporate/Other operating segment and reconciling adjustments, including interest expense on holding company debt, corporate support services revenues and expenses and income taxes, resulted in a $59 million decrease in consolidated earnings in the second quarter of 2018, compared to the same period of 2017, primarily associated with higher operating expenses and higher interest expense, partially offset by higher wholesale sales from the Pleasants Power Station due to higher market prices. Higher interest expense resulted from the issuance of $3 billion of senior notes in June 2017, proceeds of which were used to repay short-term borrowings and redeem $650 million of notes due in 2018, as well as make-whole premiums of approximately $90 million in connection with the repayment of AE Supply and AGC senior notes in the second quarter of 2018.

Summary of Results of Operations — First Six Months of 2018 Compared with First Six Months of 2017

Financial results for FirstEnergy's business segments in the first six months of 2018 and 2017 were as follows:

First Six Months 2018 Financial Results	Regulated Distribution	Regulated Transmission	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)			
Revenues:				
External				
Electric	$4,799	$ 655	$ 125	$ 5,579
Other	129	9	(37)	101
Total Revenues	4,928	664	88	5,680
Operating Expenses:				
Fuel	267	—	97	364
Purchased power	1,518	—	5	1,523
Other operating expenses	1,564	114	(11)	1,667
Provision for depreciation	396	123	74	593
Amortization (deferral) of regulatory assets, net	(259)	4	—	(255)
General taxes	379	95	30	504
Total Operating Expenses	3,865	336	195	4,396
Operating Income (Loss)	1,063	328	(107)	1,284
Other Income (Expense):				
Miscellaneous income (expense), net	112	7	(4)	115
Interest expense	(257)	(81)	(281)	(619)
Capitalized financing costs	12	19	—	31
Total Other Expense	(133)	(55)	(285)	(473)
Income (Loss) Before Income Taxes	930	273	(392)	811
Income taxes	231	70	66	367
Income (Loss) From Continuing Operations	699	203	(458)	444
Discontinued Operations, net of tax	—	—	1,224	1,224
Net Income	$699	$ 203	$ 766	$ 1,668

First Six Months 2017 Financial Results	Regulated Distribution	Regulated Transmission	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)			
Revenues:				
External				
Electric	$4,640	$ 631	$ 91	$ 5,362
Other	131	9	(23)	117
Total Revenues	4,771	640	68	5,479
Operating Expenses:				
Fuel	262	—	105	367
Purchased power	1,436	—	5	1,441
Other operating expenses	1,268	95	(31)	1,332
Provision for depreciation	357	105	42	504
Amortization of regulatory assets, net	156	5	—	161
General taxes	359	85	28	472
Total Operating Expenses	3,838	290	149	4,277
Operating Income (Loss)	933	350	(81)	1,202
Other Income (Expense):				
Miscellaneous income (loss), net	29	—	(4)	25
Interest expense	(272)	(78)	(143)	(493)
Capitalized financing costs	11	13	2	26
Total Other Expense	(232)	(65)	(145)	(442)
Income (Loss) Before Income Taxes (Benefits)	701	285	(226)	760
Income taxes (benefits)	259	105	(80)	284
Income (Loss) From Continuing Operations	442	180	(146)	476
Discontinued Operations, net of tax	—	—	(97)	(97)
Net Income (Loss)	$442	$ 180	$ (243)	$ 379

Changes Between First Six Months 2018 and First Six Months 2017 Financial Results	Regulated Distribution	Regulated Transmission	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)			
Revenues:				
External				
Electric	$159	$ 24	$ 34	$ 217
Other	(2)	—	(14)	(16)
Total Revenues	157	24	20	201
Operating Expenses:				
Fuel	5	—	(8)	(3)
Purchased power	82	—	—	82
Other operating expenses	296	19	20	335
Provision for depreciation	39	18	32	89
Amortization (deferral) of regulatory assets, net	(415)	(1)	—	(416)
General taxes	20	10	2	32
Total Operating Expenses	27	46	46	119
Operating Income (Loss)	130	(22)	(26)	82
Other Income (Expense):				
Miscellaneous income, net	83	7	—	90
Interest expense	15	(3)	(138)	(126)
Capitalized financing costs	1	6	(2)	5
Total Other Expense	99	10	(140)	(31)
Income (Loss) Before Income Taxes (Benefits)	229	(12)	(166)	51
Income taxes (benefits)	(28)	(35)	146	83
Income (Loss) From Continuing Operations	257	23	(312)	(32)
Discontinued Operations, net of tax	—	—	1,321	1,321
Net Income (Loss)	$257	$ 23	$ 1,009	$ 1,289

Regulated Distribution — First Six Months of 2018 Compared with First Six Months of 2017

Regulated Distribution's net income increased $257 million in the first six months of 2018, as compared to the same period of 2017, reflecting the reversal of a reserve on recoverability of certain REC purchases in Ohio, the net impact of a FERC settlement that reallocated certain transmission costs, higher revenues associated with increased weather-related usage and the implementation of approved rates in Ohio and Pennsylvania, as further described below, and lower net operating and miscellaneous expenses.

Revenues —

The $157 million increase in total revenues resulted from the following sources:

Revenues by Type of Service	For the Six Months Ended June 30, 2018	2017	Increase (Decrease)
	(In millions)		
Distribution services[1]	$2,633	$2,563	$ 70
Generation sales:			
Retail	1,922	1,844	78
Wholesale	244	233	11
Total generation sales	2,166	2,077	89
Other	129	131	(2)
Total Revenues	$4,928	$4,771	$ 157

[1] Includes $124 million and $113 million of ARP revenues for the six months ended June 30, 2018 and 2017, respectively.

Distribution services revenues increased $70 million, primarily resulting from the impact of approved base distribution rate increases in Pennsylvania, effective January 27, 2017, higher revenue from the DCR in Ohio, and higher weather-related customer usage as described below. Additionally, distribution revenues were impacted by higher rates associated with the recovery of deferred costs, partially offset by certain tax impacts reflected as a reduction in revenues resulting from the Tax Act. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	For the Six Months Ended June 30, 2018	2017	Increase
	(In thousands)		
Residential	27,073	24,983	8.4 %
Commercial	20,723	20,201	2.6 %
Industrial	26,275	25,663	2.4 %
Other	281	281	— %
Total Electric Distribution MWH Deliveries	74,352	71,128	4.5 %

Higher distribution deliveries to residential and commercial customers primarily reflect higher weather-related usage resulting from cooling degree days that were 22% above 2017, and 30% above normal, and heating degree days that were 20% above 2017. Deliveries to industrial customers increased reflecting higher shale and steel customer usage.

The following table summarizes the price and volume factors contributing to the $89 million increase in generation revenues for the first six months of 2018 compared to the same period of 2017:

Source of Change in Generation Revenues	Increase (Decrease) (In millions)
Retail:	
Effect of increase in sales volumes	$ 123
Change in prices	(45)
	78
Wholesale:	
Effect of decrease in sales volumes	(28)
Change in prices	28
Capacity Revenue	11
	11
Increase in Generation Revenues	$ 89

The increase in retail generation sales volumes was primarily due to higher weather-related usage, as described above. Total generation provided by alternative suppliers as a percentage of total MWH deliveries was flat across our service territory. The decrease in retail generation prices primarily resulted from lower default service auction prices in Pennsylvania and New Jersey.

Wholesale generation revenues increased $11 million in the first six months of 2018, as compared to the same period in 2017, primarily due to higher capacity revenue. The difference between current wholesale generation revenues and certain energy costs incurred are deferred for future recovery or refund, with no material impact to earnings.

Operating Expenses —

Total operating expenses increased $27 million, primarily due to the following:

- Purchased power costs increased $82 million during the first six months of 2018, as compared to the same period of 2017, primarily due to increased volumes resulting from higher customer weather-related usage, as described above, partially offset by lower unit costs reflecting lower default service auction prices.

Source of Change in Purchased Power	Increase (Decrease) (In millions)
Purchases from non-affiliates:	
Change due to decreased unit costs	$ (6)
Change due to volumes	77
	71
Purchases from affiliates:	
Change due to decreased unit costs	(7)
Change due to volumes	(10)
	(17)
Capacity	28
Increase in Purchased Power Costs	$ 82

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- Other operating expenses increased $296 million, primarily due to:
  - Increased storm restoration costs of $201 million, primarily associated with the March 2018 east coast storms, which were deferred for future recovery, resulting in no material impact on current period earnings.
  - Higher net network transmission expenses of $44 million reflecting increased transmission costs, partially offset by a FERC settlement during the second quarter of 2018 that reallocated certain transmission costs across utilities in PJM and resulted in a refund to the Ohio Companies. Except for certain transmission costs and credits 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 energy efficiency program costs of $28 million, which are deferred for future recovery, resulting in no material impact on current period earnings.
  - Higher operating and maintenance expenses of $23 million, primarily due to higher benefit costs.

- Depreciation expense increased $39 million, primarily due to a higher rate base.

- Amortization expense decreased $415 million, primarily due to increased deferral of storm restoration costs, the Ohio Supreme Court ruling regarding purchase of RECs, higher deferral of transmission and generation expenses including the net impact of the FERC settlement discussed above, and higher deferral of energy efficiency program costs.

- General taxes expense increased $20 million, primarily due to revenue-related taxes associated with increased sales volumes and higher property taxes.

Other Expense —

Total other expense decreased $99 million, primarily due to higher net miscellaneous income resulting from lower pension and OPEB non-service costs related to expected asset returns on the pension contributions discussed above, and lower capitalization, as well as lower interest expense resulting from debt maturities at JCP&L and CEI.

Income Taxes —

Regulated Distribution’s effective tax rate was 24.8% and 36.9% for the six months ended June 30, 2018 and 2017, respectively. The lower rate is primarily a result of certain impacts of the Tax Act.

Regulated Transmission — First Six Months of 2018 Compared with First Six Months of 2017

Regulated Transmission's net income increased $23 million in the first six months of 2018, as compared to the same period of 2017, primarily resulting from the impact of a higher rate base at ATSI and MAIT and higher revenues at JCP&L, partially offset by a lower rate base at TrAIL.

Revenues —

Total revenues increased $24 million, primarily due to the implementation of approved settlement rates in JCP&L, effective January 1, 2018, recovery of incremental operating expenses and a higher rate base at ATSI and MAIT, partially offset by a lower rate base at TrAIL.

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

For the Six
Months
Ended June

Revenues by Transmission Asset Owner	30, 2018	2017	Increase (Decrease)
	(In millions)		
ATSI	$327	$317	$ 10
TrAIL	127	144	(17)
MAIT	66	49	17
Other	144	130	14
Total Revenues	$664	$640	$ 24

Operating Expenses —

Total operating expenses increased $46 million, primarily due to higher operating and maintenance expenses, as well as higher property taxes and depreciation due to higher asset base. The majority of the increases are recovered through formula rates at ATSI, MAIT and TrAIL, resulting in no material impact on current period earnings.

Other Expense —

Total other expense decreased $10 million, primarily due to higher net miscellaneous income resulting from lower pension and OPEB non-service costs related to the pension contributions discussed above, higher expected asset returns and lower capitalization, as well as higher capitalized financing costs.

Income Taxes —

Regulated Transmission’s effective tax rate was 25.6% and 36.8% for the six months ended June 30, 2018 and 2017, respectively. The lower rate is primarily a result of certain impacts of the Tax Act.

Corporate / Other — First Six Months of 2018 Compared with First Six Months of 2017

Financial results from the Corporate/Other operating segment and reconciling adjustments resulted in a $312 million decrease in income from continuing operations in the first six months of 2018 compared to the same period of 2017, primarily associated with higher operating expense, higher interest expense and a higher consolidated effective tax rate, partially offset by higher wholesale sales from the Pleasants Power Station due to higher market prices. Higher interest expense resulted from FE's issuance of $3 billion of senior notes in June 2017, as well as make-whole premiums of approximately $90 million in connection with the repayment of AE Supply and AGC senior notes in the second quarter of 2018. The increase in effective tax rate is primarily due to the legal and financial separation of FES and FENOC from FirstEnergy. This separation officially eroded the ties between FES, FENOC and other FirstEnergy subsidiaries doing business in West Virginia. As such, FES and FENOC were removed from the West Virginia unitary group when calculating West Virginia state income taxes, resulting in a $126 million charge to income tax expense in continuing operations associated with the re-measurement in state deferred taxes. Additionally, the decrease in the corporate federal income tax rate from 35% to 21%, which became effective January 1, 2018, reduced income tax benefits.

For the six months ended June 30, 2018 and 2017, FirstEnergy recorded income from discontinued operations, net of tax, of $1,224 million and losses from discontinued operations, net of tax, of $97 million, respectively. Discontinued operations were comprised of the results of FES, FENOC, BSPC and a portion of AE Supply, and a gain on deconsolidation of approximately $1.2 billion, which consisted of the following:

(In millions)	For the Six Months Ended June 30, 2018
Removal of investment in FES and FENOC	$2,193
Assumption of benefit obligations retained at FE (including Pension, OPEB and EDCP)	(820)
Guarantees and credit support provided by FE	(139)
Reserve on receivables and allocated Pension/OPEB mark-to-market	(914)
Income tax benefit, including estimated worthless stock deduction	919
Gain on deconsolidation of FES and FENOC, net of tax	$1,239

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.

As a result of the Tax Act, FirstEnergy adjusted its net deferred tax liabilities at December 31, 2017, for the reduction in the corporate federal income tax rate from 35% to 21%. For the portions of FirstEnergy’s business that apply regulatory accounting, the impact of reducing the net deferred tax liabilities was offset with a regulatory liability, as appropriate, for amounts expected to be refunded to rate payers in future rates, with the remainder recorded to deferred income tax expense.

The following table provides information about the composition of net regulatory assets and liabilities as of June 30, 2018 and December 31, 2017, and the changes during the six months ended June 30, 2018:

Net Regulatory Assets (Liabilities) by Source	June 30, 2018	December 31, 2017	Increase (Decrease)
	(In millions)		
Regulatory transition costs	$33	$ 46	$ (13)
Customer payables for future income taxes	(2,765)	(2,765)	—
Nuclear decommissioning and spent fuel disposal costs	(300)	(323)	23
Asset removal costs	(753)	(774)	21
Deferred transmission costs	233	187	46
Deferred generation costs	228	198	30
Deferred distribution costs	233	258	(25)
Contract valuations	95	118	(23)
Storm-related costs	508	329	179
Other	35	46	(11)
Net Regulatory Liabilities included on the Consolidated Balance Sheets	$(2,453)	$ (2,680)	$ 227

Approximately $387 million and $201 million of regulatory assets, primarily related to storm damage costs, do not earn a current return as of June 30, 2018 and December 31, 2017, respectively, and a majority of which are currently being recovered through rates.

CAPITAL RESOURCES AND LIQUIDITY

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.

On January 22, 2018, FirstEnergy announced a $2.5 billion equity issuance, which included $1.62 billion in mandatorily convertible preferred equity with an initial conversion price of $27.42 per share and $850 million of common equity issued at $28.22 per share. The preferred shares participate in the dividend paid on common stock on an as-converted basis and are non-voting except in certain limited circumstances. The preferred shares contain an optional conversion right for holders as of July 22, 2018, and will mandatorily convert in July 2019, subject to limited exceptions. Proceeds from the investment were used to reduce holding company debt by $1.45 billion and fund the company’s pension plan by $750 million, with the remainder used for general corporate purposes. As of July 27, 2018, 224,714 shares of preferred stock have been converted into 8,195,257 shares of common stock at the option of the holders.

The equity investment strengthened FirstEnergy's balance sheet and supports the company's transition to a fully regulated utility company. By deleveraging the company, the investment also enables FirstEnergy to enhance its investment grade credit metrics and FirstEnergy does not currently anticipate the need to issue additional equity through at least 2021 outside of its regular stock investment and employee benefit plans.

In addition to this equity investment, FE and its utility and transmission subsidiaries expect their existing sources of liquidity to remain sufficient to meet their respective anticipated obligations. In addition to internal sources to fund liquidity and capital requirements for 2018 and beyond, FE and its utility and transmission subsidiaries expect 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 by certain utility and transmission subsidiaries to, among other things, fund capital expenditures and refinance short-term and maturing long-term debt, subject to market conditions and other factors.

FirstEnergy's strategy is to focus on investments in its regulated operations. The centerpiece of this strategy is the Energizing the Future transmission plan, pursuant to which FirstEnergy plans to invest $4.0 to $4.8 billion in capital investments from 2018 to 2021, including an expected $1.1 billion in 2018. 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. In total, FirstEnergy has identified over $20 billion in transmission investment opportunities across the 24,500-mile transmission system, making this a continuing platform for investment in the years beyond 2021.

In alignment with FirstEnergy’s strategy to invest in its Regulated Transmission and Regulated Distribution segments as it transitions to a fully regulated company, FirstEnergy is also focused on improving the balance sheet over time consistent with its business profile and maintaining investment grade ratings at its regulated businesses and FE. Specifically, at the regulated businesses, regulatory authority has been obtained for various regulated distribution and transmission subsidiaries to issue and/or refinance debt.

Any financing plans by FE or any of its consolidated subsidiaries, including the issuance of equity and debt, and the refinancing of short-term and maturing long-term debt are subject to market conditions and other factors. No assurance can be given that any such issuances, financing or refinancing, as the case may be, will be completed as anticipated or at all. Any delay in the completion of financing plans could require FE or any of its consolidated subsidiaries to utilize short-term borrowing capacity, which could impact available liquidity. In addition, FE and its consolidated subsidiaries expect to continually evaluate any planned financings, which may result in changes from time to time.

On March 9, 2018, FES borrowed $500 million from FE under the secured credit facility, dated as of December 6, 2016, among FES, as Borrower, FG and NG as guarantors, and FE, as lender, which fully utilized the committed line of credit available under the secured credit facility. Following deconsolidation of FES, FE fully reserved for the $500 million associated with the borrowings under the secured credit facility.

On April 20, 2018, FirstEnergy reached an agreement in principle with two groups of key FES creditors in the FES Bankruptcy. The first is an ad hoc group, which includes a majority of the pollution control revenue bonds supported by notes issued by FG and NG and the holders of senior notes issued by FES, while the second group includes the majority of Bruce Mansfield Unit 1 sale and leaseback transaction certificate holders. On May 7, 2018, FE, FES, the FES ad hoc creditor groups and the UCC entered into a Standstill Agreement, which was previously approved by the Bankruptcy Court, agreeing to keep the terms of the settlement open through August 1, 2018, and to other matters to enable an efficient settlement process, including expedited discovery protocols and transfer restrictions on the FES creditor groups. On July 31, 2018, FirstEnergy reached an updated agreement in principle with the same two groups of key FES creditors in the FES Bankruptcy and added FES, FENOC, and the UCC to such agreement in principle. In connection with the agreement in principle, the parties also extended the Standstill Agreement until the earlier of the effective date of a plan of reorganization for FES and FENOC or termination of the definitive settlement agreement. The updated agreement in principle includes the following terms, among others:

- FE will pay certain pre-petition FES and FENOC employee-related obligations, which include unfunded pension obligations and other employee benefits, and provides for the waiver of all pre-petition claims against FES and FENOC, including the full borrowings by FES under the $500 million secured credit facility, the $200 million credit agreement being used to support surety bonds, the BNSF/CSX rail settlement guarantee, and FES’ and FENOC’s unfunded pension obligations.
- The full release of all claims against FirstEnergy by FES, FENOC and their creditors.
- A $225 million cash payment from FirstEnergy.
- Up to a $628 million note from FirstEnergy, which is intended to represent the initial estimated value of the worthless stock deduction associated with the FES Bankruptcy and was designed to trade at par value when issued.
- Transfer of the Pleasants Power Station to FES for the benefit of FES’ creditors. Prior to transfer and beginning no later than January 1, 2019, FES to have an economic lease in Pleasants; AE Supply will operate Pleasants until transfer.
- FirstEnergy agrees to credit nine-months of FES’ and FENOC’s shared service costs beginning as of April 1, 2018, in an amount not to exceed $112.5 million, and FirstEnergy agrees to extend the availability of shared services until no later than June 30, 2020.
- FirstEnergy agrees to fund through its pension plan a pension enhancement should FES offer a voluntary enhanced retirement package in 2019, which is estimated to cost $15 million, and approximately $3 million for other employee benefits.

The timing of and the conditions to FirstEnergy's performance of the terms above are set forth in the agreement in principle. This agreement will be subject to approval by the FE, FES, FENOC and AE Supply Boards of Directors, the execution of definitive agreements and the approval of the Bankruptcy Court. Additionally, the Bruce Mansfield certificate holders’ support for the agreement is subject to and conditioned upon the ultimate implementation of the agreed upon treatment of certain claims of the Bruce Mansfield certificate holders. There can be no assurance that a definitive settlement agreement will be finalized and approved and, even if approved, whether the conditions to such settlement will be satisfied, and the actual outcome of this matter may differ materially from the terms of the agreement in principle described herein.

In support of the strategic review to exit competitive generation, management launched the FE Tomorrow initiative to define FirstEnergy's future organization to support its regulated business. FE Tomorrow is intended to align corporate services to efficiently support the regulated operations by ensuring that FirstEnergy has the right talent, organizational and cost structure to achieve our earnings growth targets. In support of the FE Tomorrow initiative, in June and early July 2018, nearly 500 employees in the shared services and utility services and sustainability organizations, which was more than 80% of eligible employees, accepted a voluntary enhanced retirement package, which included severance compensation and a temporary pension enhancement, with most employees departing by December 31, 2018. FirstEnergy expects further talent, organizational and cost structure adjustments in order to accomplish the FE Tomorrow goals. Management expects the cost savings resulting from the FE Tomorrow initiative to support the company's growth targets.

As of June 30, 2018, FirstEnergy's net deficit in working capital (current assets less current liabilities) was due in large part to short-term borrowings and currently payable long-term debt. Currently payable long-term debt as of June 30, 2018, consisted of the following:

Currently Payable Long-Term Debt	(In millions)
Unsecured notes	$ 725
FMBs	325
Sinking fund requirements	63
Other notes	19
	$ 1,132

Short-Term Borrowings / Revolving Credit Facilities

FE and the Utilities and FET and its subsidiaries participate in two separate five-year syndicated revolving credit facilities with aggregate commitments of $5.0 billion (Facilities), which are available through December 6, 2021. FE and the Utilities and FET and its subsidiaries may use borrowings under their Facilities for working capital and other general corporate purposes, including intercompany loans and advances by a borrower to any of its subsidiaries. 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) of no more than 65%, and 75% for FET, measured at the end of each fiscal quarter.

FirstEnergy had $1,664 million and $300 million of short-term borrowings as of June 30, 2018 and December 31, 2017, respectively. FirstEnergy's available liquidity from external sources as of June 30, 2018, was as follows:

Borrower(s)	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy[(1)]	Revolving	December 2021	$4,000	$ 2,326
FET[(2)]	Revolving	December 2021	1,000	1,000
		Subtotal	$5,000	$ 3,326
	Cash and cash equivalents		—	256
		Total	$5,000	$ 3,582

(1) FE and the Utilities. Available liquidity includes impact of $10 million of LOCs issued under various terms.
(2) Includes FET, ATSI, MAIT and TrAIL.

The following table summarizes the borrowing sub-limits for each borrower under the facilities, the limitations on short-term indebtedness applicable to each borrower under current regulatory approvals and applicable statutory and/or charter limitations as of June 30, 2018:

Borrower	FirstEnergy Revolving Credit Facility Sub-Limit	FET Revolving Credit Facility Sub-Limit	Regulatory and Other Short-Term Debt Limitations	
	(In millions)			
FE	$4,000	$ —	$ —	(1)
FET	—	1,000	—	(1)
OE	500	—	500	(2)
CEI	500	—	500	(2)
TE	500	—	300	(2)
JCP&L	600	—	500	(2)
ME	300	—	500	(2)
PN	300	—	300	(2)
WP	200	—	200	(2)
MP	500	—	500	(2)
PE	150	—	150	(2)
ATSI	—	500	500	(2)
Penn	50	—	100	(2)
TrAIL	—	400	400	(2)
MAIT	—	400	400	(2)

(1) No limitations.
(2) Includes amounts which may be borrowed under the regulated companies' money pool.

$250 million of the FE Facility and $100 million of the FET Facility, subject to each borrower’s sub-limit, is available for the issuance of LOCs (subject to borrowings drawn under the Facilities) expiring up to one year from the date of issuance. The stated amount of outstanding LOCs will count against total commitments available under each of the Facilities and against the applicable borrower’s borrowing sub-limit.

The Facilities do not contain provisions that restrict the ability to borrow or accelerate payment of outstanding advances in the event of any change in credit ratings of the borrowers. Pricing is defined in “pricing grids,” whereby the cost of funds borrowed under the facilities is related to the credit ratings of the company borrowing the funds, other than the FET facility, which is based on its subsidiaries' credit ratings. Additionally, borrowings under each of the Facilities are subject to the usual and customary provisions for acceleration upon the occurrence of events of default, including a cross-default for other indebtedness in excess of $100 million.

As of June 30, 2018, the borrowers were in compliance with the applicable debt-to-total-capitalization ratio covenants, as well as in the case of FE, the minimum interest coverage ratio requirement, in each case as defined under the respective Facilities.

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. Similar but separate arrangements exist among

FirstEnergy’s unregulated companies with AE Supply, FE, FET, FEV and certain other unregulated subsidiaries of FE participating in a money pool. FESC administers these money pools and tracks surplus funds of FirstEnergy and the respective regulated and unregulated subsidiaries, as the case may be, as well as proceeds available from bank borrowings. Companies receiving a loan under the money pool agreements must repay the principal amount of the loan, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from their respective pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings in the first six months of 2018 was 2.18% per annum for the regulated companies’ money pool and 2.61% per annum for the unregulated companies’ money pool.

On March 16, 2018, FES and FENOC withdrew from the unregulated companies' money pool, which included FE, FES and FENOC. As of the date of the withdrawal, FES and FENOC owed FE approximately $4 million in unsecured borrowings in the aggregate under the money pool. In addition, as of March 31, 2018, AE Supply had a $102 million outstanding unsecured promissory note owed from FES. Following deconsolidation of FES and FENOC, FE fully reserved the $4 million associated with the outstanding unsecured borrowings under the unregulated companies' money pool and the $102 million associated with the AE Supply unsecured promissory note.

Long-Term Debt Capacity

FE's and its subsidiaries' access to capital markets and costs of financing are influenced by the credit ratings of their securities. The following table displays FE’s and its subsidiaries’ credit ratings as of July 31, 2018:

	Senior Secured			Senior Unsecured		
Issuer	S&P	Moody’s	Fitch	S&P	Moody’s	Fitch
FE	—	—	—	BB+	Baa3	BBB-
AGC	—	—	—	—	—	BB
ATSI	—	—	—	BBB-	Baa1	BBB+
CEI	BBB+	Baa1	A-	BBB-	Baa3	BBB+
FET	—	—	—	BB+	Baa2	BBB-
JCP&L	—	—	—	BBB-	Baa2	BBB
ME	—	—	—	BBB-	A3	BBB+
MAIT	—	—	—	BBB-	Baa1	BBB+
MP	BBB+	A3	BBB+	BBB-	Baa2	—
OE	BBB+	A2	A-	BBB-	Baa1	BBB+
PN	—	—	—	BBB-	Baa1	BBB+
Penn	—	A2	A-	—	—	—
PE	—	—	BBB+	—	—	—
TE	BBB+	Baa1	A-	—	—	—
TrAIL	—	—	—	BBB-	A3	BBB+
WP	—	—	A-	—	—	—

Debt capacity is subject to the consolidated debt-to-total-capitalization limits in the credit facilities previously discussed. As of June 30, 2018, FE and its subsidiaries could issue additional debt of approximately $10.7 billion, or incur a $5.8 billion reduction to equity, and remain within the limitations of the financial covenants required by the FE Facility.

Changes in Cash Position

As of June 30, 2018, FirstEnergy had $256 million of cash and cash equivalents and approximately $68 million of restricted cash compared to $589 million of cash and cash equivalents and approximately $54 million of restricted cash as of December 31, 2017 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. The most significant use of cash from operating activities is buying electricity in the wholesale market and paying fuel suppliers, employees, tax authorities, lenders and others for a wide range of materials and services.

FirstEnergy's Consolidated Statement of Cash Flows combines cash flows from discontinued operations with cash flows from continuing operations within each cash flow statement category. The following table summarizes the major classes of cash flow items as discontinued operations for the six months ended June 30, 2018 and 2017:

	For the Six Months Ended June 30,	
(In millions)	2018	2017

CASH FLOWS FROM OPERATING ACTIVITIES:		
Income (loss) from discontinued operations	$1,224	$(97)
Depreciation and amortization, including nuclear fuel, regulatory assets, net, intangible assets and deferred debt-related costs	47	157
Unrealized (gain) loss on derivative transactions	(10)	53

Net cash used for operating activities was $288 million during the first six months of 2018 compared with $1,482 million provided from operating activities during the first six months of 2017. Key changes in cash flows from operations in the first six months of 2018, compared in the same period of 2017, primarily were as follows:

- a $1.25 billion increase in cash contributions to the qualified pension plan;

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- a $93 million coal supply agreement settlement payment by AE Supply in the first quarter of 2018;
- the absence of FES' cash from operations in the second quarter of 2018; partially offset by
- higher transmission revenue, reflecting recovery of incremental operating expenses, a higher rate base at ATSI and MAIT, and the implementation of new rates at JCP&L; and
- higher distribution services retail receipts reflecting higher weather-related usage and the implementation of approved rates in Ohio and Pennsylvania.

Cash Flows From Financing Activities

In the first six months of 2018, cash provided from financing activities was $1,534 million compared to cash used for financing activities of $56 million in the first six months of 2017. The following table summarizes new debt financing, equity investments, redemptions, repayments, make-whole premiums paid on debt redemptions, short-term borrowings and dividends:

	For the Six Months Ended June 30,	
Securities Issued or Redeemed / Repaid	2018	2017
	(In millions)	
New Issues		
Unsecured notes	$450	$3,000
FMBs	—	250
Term Loan	—	250
	$450	$3,500
Preferred stock issuance	$1,616	$—
Common stock issuance	$850	$—
Redemptions / Repayments		
Unsecured notes	$(555)	$(380)
FMBs	—	(150)
Term Loan	(1,450)	—
PCRBs	(216)	(158)
Senior secured notes	(30)	(47)
	$(2,251)	$(735)
Make-whole premiums paid on debt redemptions	$(89)	$—
Short-term borrowings (repayments), net	$1,364	$(2,450)
Preferred stock dividend payments	$(42)	$—
Common stock dividend payments	$(343)	$(319)

On January 22, 2018, FE entered into agreements for the private placement of its equity securities representing an approximately $2.5 billion investment in the Company, including $1.62 billion in mandatorily convertible preferred equity and $850 million of common equity.

On January 22, 2018, FE repaid $1.2 billion of a variable rate syndicated term loan and two separate $125 million term loans using the proceeds from the $2.5 billion equity investment as discussed above.

On May 3, 2018, AGC redeemed $100 million of 5.06% senior notes due 2021 and paid $5.7 million in related make-whole premiums in connection with the redemption.

On May 10, 2018, MAIT issued $450 million of 4.10% senior notes due 2028. Proceeds from the issuance of the notes were used to establish a capital structure, to finance capital improvements and for general corporate purposes, including funding working capital needs and day-to-day operations.

On June 4, 2018, AE Supply repaid approximately $155 million of 5.75% senior notes due 2019 and approximately $150 million of 6.75% senior notes due 2039, respectively, and paid $83.3 million in related make-whole premiums in connection with repayments.

On June 4, 2018, AE Supply and MP caused to be redeemed $73.5 million of 5.50% PCRBs due 2037.

On July 10, 2018, such PCRBs were refinanced as MP issued its $73.5 million pollution control note in connection with the issuance of $73.5 million of 3.0% PCRBs with a mandatory put in October 2021.

On June 11, 2018, AE Supply caused to be redeemed $142 million of 5.25% PCRBs due 2037.

On June 15, 2018, JCP&L retired $150 million of 4.8% senior notes at maturity.

Cash Flows From Investing Activities

Cash used for investing activities in the first six months of 2018 principally represented cash used for property additions and an increase in notes receivable from affiliated companies. The following table summarizes investing activities for the first six months of 2018 and the comparable period of 2017:

Cash Used for Investing Activities[(1)]	For the Six Months Ended June 30, 2018	2017	Increase (Decrease)
	(In millions)		
Property Additions:			
Regulated Distribution	$655	$568	$ 87
Regulated Transmission	574	469	105
Corporate / Other	78	217	(139)
Nuclear fuel	—	134	(134)
Proceeds from asset sales	(390)	—	(390)
Investments	33	48	(15)
Notes receivable from affiliated companies	500	—	500
Asset removal costs	118	79	39
Other	(3)	—	(3)
	$1,565	$1,515	$ 50

(1) See Note 3, "Discontinued Operations" for major classes of discontinued operations for cash used for investing activities.

Cash used for investing activities for the first six months of 2018 increased $50 million, compared to the same period of 2017, primarily due to an increase in notes receivable from affiliated companies, higher property additions and asset removal costs, partially offset by the absence of nuclear fuel purchases and proceeds from asset sales. The increase in notes receivable from affiliated companies and property additions were due to the following:

- an increase of $500 million in notes receivable from affiliated companies resulting from FES' borrowings from the committed line of credit available under the secured credit facility with FE;
- an increase of $87 million at Regulated Distribution due to an increase in storm restoration work;
- an increase of $105 million at Regulated Transmission due to timing of capital investments associated with its Energizing the Future investment program; partially offset by
- a decrease of $139 million at Corporate/Other due to lower competitive generation investments.

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, 2018, was approximately $1.7 billion, as summarized below:

Guarantees and Other Assurances	Maximum Exposure (In millions)
FE's Guarantees and Assurances on Behalf of FES and FENOC	
Energy and Energy-Related Contracts(1)	$ 7
Surety Bonds - FG(2)	200
Deferred compensation arrangements	147
	354
FE's Guarantees on Behalf of its Consolidated Subsidiaries	
AE Supply asset sales(3)	555
Deferred compensation arrangements	450
Other	5
	1,010
FE's Guarantees on Behalf of Business Ventures	
Global Holding facility	235
Other Assurances	
Surety Bonds	118
LOCs(4)	10
	128
Total Guarantees and Other Assurances	$ 1,727

(1) Issued for open-ended terms, with a 10-day termination right by FirstEnergy. As of June 30, 2018, FE recorded an obligation for these guarantees in other non-current liabilities with a corresponding loss from discontinued operations.

(2) FE provides credit support for FG surety bonds of $169 million and $31 million for the benefit of the PA DEP with respect to LBR CCR impoundment closure and post-closure activities and the Hatfield's Ferry CCR disposal site, respectively.

(3) As a condition to closing AE Supply's sale of four natural gas plants in December 2017, FE provided the purchaser two limited three-year guarantees totaling $555 million of certain obligations of AE Supply and AGC.

(4) Includes $10 million issued for various terms pursuant to LOC capacity available under FirstEnergy’s revolving credit facilities.

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 ratings 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 AE Supply's power portfolio exposure as of June 30, 2018, AE Supply has posted collateral of $2 million. The Utilities and FET have posted collateral of $10 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. The following table discloses the potential additional credit rating contingent contractual collateral obligations as of June 30, 2018.

Potential Collateral Obligations	AE Supply	Utilities and FET	FE	Total
	(In millions)			
Contractual Obligations for Additional Collateral				
At Current Credit Rating	$ 1	$ —	$—	$1
Upon Further Downgrade	—	56	—	56
Surety Bonds (Collateralized Amount)	1	59	235	295
Total Exposure from Contractual Obligations	$ 2	$ 115	$235	$352

Surety Bonds are not tied to a credit rating. Surety Bonds' impact assumes maximum contractual obligations (typical obligations require 30 days to cure). FE provides credit support for FG surety bonds of $169 million and $31 million for the benefit of the PA DEP with respect to LBR CCR impoundment closure and post-closure activities and the Hatfield's Ferry CCR disposal site, respectively.

Other Commitments and Contingencies

FE is a guarantor under a $300 million syndicated senior secured term loan facility due March 3, 2020, under which Global Holding's outstanding balance is $235 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 guarantees 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.

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 has limited exposure 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.

The valuation of derivative contracts is based on observable market information. As of June 30, 2018, FirstEnergy has a net liability of $65 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.

Equity Price Risk

As of June 30, 2018, the FirstEnergy pension plan assets were allocated approximately as follows: 40% in equity securities, 39% in fixed income securities, 10% in absolute return strategies, 8% in real estate, 1% in private equity, and 2% 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. In January 2018, FirstEnergy satisfied its minimum required funding obligations to its qualified pension plan of $500 million and addressed funding obligations for future years with an additional contribution of $750 million. See Note 5, "Pension and Other Postemployment Benefits," of the Notes to Consolidated Financial Statements for additional details on FirstEnergy's pension plans and OPEB. Through June 30, 2018, FirstEnergy's pension plan assets lost approximately 1.1% as compared to an annual expected return on plan assets of 7.5%.

As of June 30, 2018, FirstEnergy's OPEB plans were invested in fixed income and equity securities. Through June 30, 2018, FirstEnergy's OPEB plans have earned approximately 1.5% as compared to an annual expected return on plan assets of 7.5%.

NDT funds have been established to satisfy JCP&L, ME and PN's nuclear decommissioning obligations associated with TMI-2. As of June 30, 2018, approximately 62% of the funds were invested in fixed income securities, 36% of the funds were invested in equity securities and 2% were invested in short-term investments, with limitations related to concentration and investment grade ratings. The investments are carried at their market values of approximately $510 million, $295 million and $13 million for fixed income securities, equity securities and short-term investments, respectively, as of June 30, 2018, excluding $(12) million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $29 million reduction in fair value as of June 30, 2018. A decline in the value of JCP&L, ME and PN's NDTs or a significant escalation in estimated decommissioning costs could result in additional funding requirements. During the six months ended June 30, 2018, JCP&L, ME and PN made no contributions to the NDTs.

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, 2018.

CREDIT RISK

Credit risk is the risk that FirstEnergy would incur a loss as a result of nonperformance by counterparties of their contractual obligations. FirstEnergy maintains credit policies and procedures with respect to counterparty credit (including requirements that counterparties maintain specified credit ratings) and require other assurances in the form of credit support or collateral in certain circumstances in order to limit counterparty credit risk. However, FirstEnergy, as applicable, has concentrations of suppliers and customers among electric utilities, financial institutions and energy marketing and trading companies. These concentrations may impact FirstEnergy's overall exposure to credit risk, positively or negatively, as counterparties may be similarly affected by changes in economic, regulatory or other conditions. In the event an energy supplier of the Ohio Companies, Pennsylvania Companies, JCP&L and PE defaults on its obligation, the Ohio Companies, Pennsylvania Companies, JCP&L and PE would be required to seek replacement power in the market. In general, subject to regulatory review or other processes, appropriate incremental costs incurred by these entities would be recoverable from customers through applicable rate mechanisms, thereby mitigating the financial risk for these entities. FirstEnergy's credit policies to manage credit risk include the use of an established credit approval process, daily monitoring of counterparty positions and the use of master netting agreements or provisions. These agreements generally include credit mitigation provisions, such as margin, prepayment or collateral requirements. FirstEnergy and its subsidiaries may request additional credit assurance, in certain circumstances, in the event that the counterparties' credit ratings fall below investment grade, their tangible net worth falls below specified percentages or their exposures exceed an established credit limit.

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. In addition, if any of the FirstEnergy affiliates were to engage in the construction of significant new transmission facilities, depending on the state, they may be required to obtain state regulatory authorization to site, construct and operate the new transmission facility.

Following the adoption of the Tax Act, various state regulatory proceedings have been initiated to investigate the impact of the Tax Act on the Utilities’ rates and charges. State proceedings that have arisen are discussed below. The Utilities continue to monitor and investigate the impact of state regulatory proceedings resulting from the Tax Act.

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. On July 16, 2015, the MDPSC issued an order setting new incremental energy savings goals for 2017 and beyond, beginning with the goal of 0.97% savings achieved under PE's plan for 2016, and increasing 0.2% per year thereafter to reach 2%. The Maryland legislature in April 2017 adopted a statute requiring the same 0.2% per year increase, up to the ultimate goal of 2% annual savings, for the duration of the 2018-2020 and 2021-2023 EmPOWER Maryland program cycles, to the extent the MDPSC determines that cost-effective programs and services are available. PE's approved 2018-2020 EmPOWER Maryland plan continues and expands upon prior years' programs, and adds new programs, for a projected total cost of $116 million over the three-year period. On December 22, 2017, the MDPSC issued an order approving the 2018-2020 plan with various modifications. PE recovers 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 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. 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 2013 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 2013 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, as well as 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 Maryland 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 issued a ruling on any of those matters.

On September 26, 2016, the MDPSC initiated a new proceeding to consider an array of issues relating to electric distribution system design, including matters relating to electric vehicles, distributed energy resources, advanced metering infrastructure, energy storage, system planning, rate design, and impacts on low-income customers. Comments were filed and a hearing was held in late 2016. On January 31, 2017, the MDPSC issued a notice establishing five working groups to address these issues over the following eighteen months, and also directed the retention of an outside consultant to prepare a report on costs and benefits of distributed solar generation in Maryland. On January 19, 2018, PE filed a joint petition, along with other utility companies, work group stakeholders, and the MDPSC electric vehicle work group leader, to implement a statewide electric vehicle portfolio. If approved, PE will launch an electric vehicle charging infrastructure program on January 1, 2019, offering up to 2,000 rebates for electric vehicle charging equipment to residential customers, and deploying up to 259 chargers at non-residential customer service locations at a projected total cost of $12 million. PE is proposing to recover program costs subject to a five-year amortization. On February 6, 2018, the MDPSC opened a new proceeding to consider the petition and numerous parties filed comments on the petition on March 27, 2018, and the MDPSC held a hearing on the petition in May 2018. In an order issued July 2, 2018, the MDPSC directed the parties to conduct more discovery on the matter, then file additional comments by August 30, 2018, after which a second hearing will be conducted in early September 2018.

On January 12, 2018, the MDPSC instituted a proceeding to examine the impacts of the Tax Act on the rates and charges of Maryland utilities. PE was required to track and apply regulatory accounting treatment for the impacts beginning January 1, 2018, and submitted a report to the MDPSC on February 15, 2018, estimating that the Tax Act impacts would be approximately $7 million to $8 million annually for PE’s customers. PE proposed to file a base rate case in the third quarter of 2018 where the benefits from the effects of the Tax Act will be realized by customers through a lower rate increase than would otherwise be necessary.

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.

JCP&L currently operates under rates that were approved by the NJBPU on December 12, 2016, effective as of January 1, 2017. These rates provide an annual increase in operating revenues of approximately $80 million from those previously in place and are intended 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. In addition, on January 25, 2017, the NJBPU approved the acceleration of the amortization of JCP&L’s 2012 major storm expenses that are recovered through the SRC in order for JCP&L to achieve full recovery by December 31, 2019.

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 included operational and financial components. The independent consultant conducting the review issued a final report on July 27, 2016, recognizing that JCP&L is meeting the NJBPU requirements and making various operational and financial recommendations. The NJBPU issued an Order on August 24, 2016, that accepted the independent consultant’s final report and directed JCP&L, the Division of Rate Counsel and other interested parties to address the recommendations.

In an Order issued October 22, 2014, in a generic proceeding to review its policies with respect to the use of a CTA in base rate cases, 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 Superior Court of New Jersey Appellate Division and JCP&L filed to participate as a respondent in that proceeding supporting the order. On September 18, 2017, the Superior Court of New Jersey Appellate Division reversed the NJBPU's Order on the basis that the NJBPU's modification of its CTA methodology did not comply with the procedures of the NJAPA. JCP&L's existing rates are not expected to be impacted by this order. On December 19, 2017, the NJBPU approved the issuance of proposed rules to modify the CTA methodology consistent with its October 22, 2014, Generic Order, which were published in the NJ Register on January 16, 2018, and republished on February 6, 2018, to correct an error. JCP&L filed comments supporting the proposed rulemaking on April 6, 2018.

At the December 19, 2017, NJBPU public meeting, the NJBPU approved its IIP rulemaking. The IIP creates a financial incentive for utilities to accelerate the level of investment needed to promote the timely rehabilitation and replacement of certain non-revenue producing components that enhance reliability, resiliency, and/or safety. On July 13, 2018, JCP&L filed an infrastructure plan, JCP&L Reliability Plus, which proposed to accelerate $386.8 million of electric distribution infrastructure investment over four years to enhance the reliability and resiliency of its distribution system and reduce the frequency and duration of power outages. JCP&L requested that the NJBPU issue a final order in December 2018.

On January 31, 2018, the NJBPU instituted a proceeding to examine the impacts of the Tax Act on the rates and charges of New Jersey utilities. The NJBPU ordered New Jersey utilities to: (1) defer on their books the impacts of the Tax Act effective January 1, 2018; (2) to file tariffs effective April 1, 2018, reflecting the rate impacts of changes in current taxes; and (3) to file tariffs effective July 1, 2018, reflecting the rate impacts of changes in deferred taxes. On March 2, 2018, JCP&L filed a petition with the NJBPU, which included proposed tariffs for a base rate reduction of $28.6 million effective April 1, 2018, and a rider to reflect $1.3 million in rate impacts of changes in deferred taxes. On March 26, 2018, the NJBPU approved JCP&L’s rate reduction effective April 1, 2018, on an interim basis subject to refund, pending the outcome of this proceeding. The NJBPU, however, did not address refunds and other proposed rider tariffs at such time, but may be addressed at a later date.

OHIO

The Ohio Companies currently operate under ESP IV which commenced June 1, 2016 and expires May 31, 2024. The material terms of ESP IV, as approved in the PUCO’s Opinion and Order issued on March 31, 2016 and Fifth Entry on Rehearing on October 12, 2016, include Rider DMR, which provides for the Ohio Companies to collect $132.5 million annually for three years, with the possibility of a two-year extension. Rider DMR will be grossed up for federal income taxes, resulting in an approved amount of approximately $168 million annually in 2018 and 2019. Revenues from Rider DMR will be excluded from the significantly excessive earnings test for the initial three-year term but the exclusion will be reconsidered upon application for a potential two-year extension. The PUCO set three conditions for continued recovery under Rider DMR: (1) retention of the corporate headquarters and nexus of operations in Akron, Ohio; (2) no change in control of the Ohio Companies; and (3) a demonstration of sufficient progress in the implementation of grid modernization programs approved by the PUCO. ESP IV also continues a base distribution rate freeze through May 31, 2024. In addition, ESP IV continues the supply of power to non-shopping customers at a market-based price set through an auction process.

ESP IV also continues Rider DCR, which supports continued investment related to the distribution system for the benefit of customers, with increased revenue caps of $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. Other material terms of ESP IV include: (1) the collection of lost distribution revenues associated with energy efficiency and peak demand reduction programs; (2) an agreement to file a Grid Modernization Business Plan for PUCO consideration and approval (which filing was made on February 29, 2016, and remains pending); (3) a goal across FirstEnergy to reduce CO_2 emissions by 90% below 2005 levels by 2045; (4) contributions, totaling $51 million to: (a) fund energy conservation programs, economic development and job retention in the Ohio Companies' service territories; (b) establish a fuel-fund in each of the Ohio Companies' service territories to assist low-income customers; and (c) establish a Customer Advisory Agency to ensure preservation and growth of the competitive market in Ohio; and (5) an agreement to file an application to transition to a straight fixed variable cost recovery mechanism for residential customers' base distribution rates, which filing was made on April 3, 2017, and which the PUCO denied on June 13, 2018.

Several parties, including the Ohio Companies, filed applications for rehearing regarding the Ohio Companies' ESP IV with the PUCO. The Ohio Companies' application for rehearing challenged, among other things, the PUCO's failure to adopt the Ohio Companies' suggested modifications to Rider DMR. The Ohio Companies had previously suggested that a properly designed Rider DMR would be valued at $558 million annually for eight years, and include an additional amount that recognizes the value of the economic impact of FirstEnergy maintaining its headquarters in Ohio. Other parties' applications for rehearing argued, among other things, that the PUCO's adoption of Rider DMR is not supported by law or sufficient evidence. On August 16, 2017, the PUCO denied all remaining intervenor applications for rehearing, denied the Ohio Companies' challenges to the modifications to Rider DMR and added a third-party monitor to ensure that Rider DMR funds are spent appropriately. On September 15, 2017, the Ohio Companies filed an application for rehearing of the PUCO's August 16, 2017 ruling on the issues of the third-party monitor and the ROE calculation for advanced metering infrastructure. On October 11, 2017, the PUCO denied the Ohio Companies' application for rehearing on both issues. On October 16, 2017, the Sierra Club and the OMAEG filed notices of appeal with the Supreme Court of Ohio appealing various PUCO entries on their applications for rehearing. On November 16, 2017, the Ohio Companies intervened in the appeal. Additional parties subsequently filed notices of appeal with the Supreme Court of Ohio challenging various PUCO entries on their applications for rehearing. On February 26, 2018, appellants filed their briefs. Briefs of the PUCO and the Ohio Companies were filed on May 29, 2018. On July 9, 2018, appellants filed their reply briefs. On July 30, 2018, OCC, the NOAC, and the OMAEG filed a joint motion with the Supreme Court of Ohio to stay the portions of the PUCO's orders and entries under appeal that authorized Rider DMR. The Ohio Companies responded on July 31, 2018.

Under ORC 4928.66, the Ohio Companies are required to implement energy efficiency programs that achieve certain annual energy savings and total peak demand reductions. Starting in 2017, ORC 4928.66 requires the energy savings benchmark to increase by 1% and the peak demand reduction benchmark to increase by 0.75% annually thereafter through 2020 and the energy savings benchmark to increase by 2% annually from 2021 through 2027, with a cumulative benchmark of 22.2% by 2027. 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 ORC 4928.66 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. On December 9, 2016, the Ohio Companies filed a Stipulation and Recommendation with several parties that contained changes to the plan and a decrease in the plan costs. The Ohio Companies anticipate the cost of the plans will be approximately $268 million over the life of the portfolio plans and such costs are expected to be recovered through the Ohio Companies’ existing rate mechanisms. On November 21, 2017, the PUCO issued an order that approved the filed Stipulation and Recommendation with several modifications, including a cap on the Ohio Companies’ collection of program costs and shared savings set at 4% of the Ohio Companies’ total sales to customers as reported on 2015 FERC Form 1. On December 21, 2017, the Ohio Companies filed an application for rehearing challenging the PUCO’s modification of the Stipulation and Recommendation to include the 4% cost cap, which was denied by the PUCO on January 10, 2018. On March 12, 2018, the Ohio Companies filed a Notice of Appeal with the Supreme Court of Ohio challenging the PUCO’s imposition of a 4% cost cap. Various other parties also filed Notices of Appeal challenging various PUCO entries on their applications for rehearing. The Ohio Companies filed their brief on May 21, 2018.

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, except that in 2014 SB310 froze 2015 and 2016 requirements at the 2014 level (2.5%), pushing back scheduled increases, which resumed in 2017 (3.5%), and increases 1% each year through 2026 (to 12.5%) and shall remain at 12.5% in 2027 and each year thereafter. 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. The OCC and the ELPC also filed appeals of the PUCO's order. On January 24, 2018, the Supreme Court of Ohio reversed the PUCO order finding that the order violated the rule against retroactive ratemaking. On February 5, 2018, the OCC and ELPC filed a motion for reconsideration, to which the Ohio Companies responded in opposition on February 15, 2018. On April 25, 2018, the Supreme Court of Ohio denied the motion for reconsideration. As a result, the Ohio Companies recognized a pre-tax benefit to earnings (within the Amortization (deferral) of regulatory assets, net line on the Consolidated Statement of Income) of approximately $72 million to reverse the liability associated with the PUCO opinion and order.

On December 1, 2017, the Ohio Companies filed an application with the PUCO for approval of a DPM Plan. The DPM Plan is a portfolio of approximately $450 million in distribution platform investment projects, which are designed to modernize the Ohio Companies’ distribution grid, prepare it for further grid modernization projects, and provide customers with immediate reliability benefits. The Ohio Companies have requested that the PUCO issue an order approving the DPM Plan and associated cost recovery so that the Ohio Companies can expeditiously commence the DPM Plan and customers can begin to realize the associated benefits.

On January 10, 2018, the PUCO opened a case to consider the impacts of the Tax Act and determine the appropriate course of action to pass benefits on to customers. The Ohio Companies, effective January 1, 2018, were required to establish a regulatory liability for the estimated reduction in federal income tax resulting from the Tax Act, and filed comments on February 15, 2018, explaining that customers will save nearly $40 million annually as a result of updating tariff riders for the tax rate changes and that the Ohio Companies' base distribution rates are not impacted by the Tax Act changes because they are frozen through May 2024. The Ohio Companies filed reply comments on March 7, 2018.

PENNSYLVANIA

The Pennsylvania Companies operate under DSPs for the June 1, 2017 through May 31, 2019 delivery period, which 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 DSPs, the supply will 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. The DSPs include modifications to the Pennsylvania Companies' POR programs in order to reduce the level of uncollectible expense the Pennsylvania Companies experience associated with alternative EGS charges.

On December 11, 2017, the Pennsylvania Companies filed DSPs for the June 1, 2019 through May 31, 2023 delivery period. Under the 2019-2023 DSPs, the supply is proposed to be provided by wholesale suppliers through a mix of 3, 12 and 24-month energy contracts, as well as two RFPs for 2-year SREC contracts for ME, PN and Penn. The 2019-2023 DSPs as proposed also include modifications to the Pennsylvania Companies' POR programs in order to continue their clawback pilot program as a long-term, permanent program. The 2019-2023 DSPs also introduce a retail market enhancement rate mechanism designed to stimulate residential customer shopping, and modifications to the Pennsylvania Companies' customer class definitions to allow for the introduction of hourly priced default service to customers at or above 100kW. A hearing was held on April 10, 2018, and the ALJ issued a recommended decision dated May 31, 2018. The decision recommended approval of the Pennsylvania Companies' DSPs as originally proposed with two exceptions: it recommended rejecting the proposed retail market enhancement rate mechanism, and establishing limitations on customer assistance program customers' shopping. Exceptions were filed by two parties on June 28, 2018, to which the Pennsylvania Companies filed reply exceptions on July 9, 2018. The PPUC is expected to issue a final order on these DSPs by mid-September 2018.

The Pennsylvania Companies operate under rates that were approved by the PPUC on January 19, 2017, effective as of January 27, 2017. These rates provide annual increases in operating revenues of approximately $96 million at ME, $100 million at PN, $29 million at Penn, and $66 million at WP, and are intended to benefit customers by modernizing the grid with smart technologies, increasing vegetation management activities, and continuing other customer service enhancements.

Pursuant to Pennsylvania's EE&C legislation in Act 129 of 2008 and PPUC orders, Pennsylvania EDCs implement energy efficiency and peak demand reduction programs. On June 19, 2015, the PPUC issued a Phase III Final Implementation Order setting: demand reduction targets, relative to each Pennsylvania Companies' 2007-2008 peak demand (in MW), at 1.8% for ME, 1.7% for Penn, 1.8% for WP, and 0% for PN; and energy consumption reduction targets, as a percentage of each Pennsylvania Companies' historic 2010 forecasts (in MWH), at 4.0% for ME, 3.9% for PN, 3.3% for Penn, and 2.6% for WP. The Pennsylvania Companies' Phase III EE&C plans for the June 2016 through May 2021 period, which were approved in March 2016, with expected costs up to $390 million, are designed to achieve the targets established in the PPUC's Phase III Final Implementation Order with full recovery through the reconcilable EE&C riders.

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 February 11, 2016, the PPUC approved LTIIPs for each of the Pennsylvania Companies. On June 14, 2017, the PPUC approved modified LTIIPs for ME, PN and Penn for the remaining years of 2017 through 2020 to provide additional support for reliability and infrastructure investments. The LTIIPs estimated costs for the remaining period of 2018 to 2020 are: WP $50.1 million; PN $44.8 million; Penn $33.2 million; and ME $51.3 million. On April 10, 2018, the PPUC notified each of the Pennsylvania Companies that the PPUC was initiating a review of the LTIIPs as required by regulation once every five years, and soliciting comments from interested parties. On May 10, 2018, the Pennsylvania Companies each filed comments explaining that their LTIIPs are effective and that changes to the respective LTIIPs are not necessary. No parties other than the Pennsylvania Companies filed comments.

On February 16, 2016, the Pennsylvania Companies filed riders for PPUC approval for quarterly cost recovery, which were approved by the PPUC on June 9, 2016, and went into effect July 1, 2016, subject to hearings and refund or reallocation among customer classes. On January 19, 2017, in the PPUC's order approving the Pennsylvania Companies' general rate cases, the PPUC added an additional issue to the DSIC proceeding to include whether ADIT should be included in DSIC calculations. On February 2, 2017, the parties to the DSIC proceeding submitted a Joint Settlement to the ALJ that resolved the issues that were pending from the order issued on June 9, 2016. On August 31, 2017, the ALJ issued a decision recommending that the complaint of the Pennsylvania OCA be granted by the PPUC such that the Pennsylvania Companies reflect all federal and state income tax deductions related to DSIC-eligible property in the currently effective DSIC rates. On April 19, 2018, the PPUC approved the Joint Settlement without modification and reversed the ALJ's decision that would have required the Pennsylvania Companies to reflect all federal and state income tax deductions related to DSIC-eligible property in currently effective DSIC rates. On May 21, 2018, the Pennsylvania OCA filed an appeal with the Pennsylvania Commonwealth Court of the PPUC's decision of April 19, 2018. On June 11, 2018, the Pennsylvania Companies filed a Notice of Intervention in the Pennsylvania OCA's appeal to Commonwealth Court.

On February 12, 2018, the PPUC initiated a proceeding to determine the effects of the Tax Act on the tax liability of utilities and the feasibility of reflecting such impacts in rates charged to customers. On March 9, 2018, the Pennsylvania Companies submitted their calculation of the net annual effect of the Tax Act on income tax expense and rate base to be $37 million for ME, $40 million for PN, $9 million for Penn, and $30 million for WP. The Pennsylvania Companies also filed comments proposing that rates be adjusted to reflect the tax rate changes prospectively from the date of a final PPUC order via a reconcilable rider, with the amount that would otherwise accrue between January 1, 2018 and the date of a final order being used to invest in the Pennsylvania Companies' infrastructure. On March 15, 2018, the PPUC issued a Temporary Rates Order making the Pennsylvania Companies' rates temporary and subject to refund for six months. On May 17, 2018, the PPUC issued orders directing that the Pennsylvania Companies implement a reconcilable negative surcharge mechanism in order to refund to customers the net effect of the Tax Act for the period July 1, 2018, through December 31, 2018, to be prospectively updated for new rates effective January 1, 2019. The Pennsylvania Companies were also directed to establish a regulatory liability for the net impact of the Tax Act for the period of January 1, 2018 through June 30, 2018. On June 14, 2018, the PPUC issued an order revising this directive such that the Pennsylvania Companies must instead establish accounts to track tax savings for the period January 1, 2018, through March 14, 2018, and record regulatory liabilities associated with tax savings for only the period March 15, 2018 through June 30, 2018. The cumulative value of the tracked amounts and the regulatory liability is expected to amount to $12 million for ME, $13 million for PN, $3 million for Penn, and $10 million for WP. These amounts are expected to be addressed in the Pennsylvania Companies' next available rate proceedings, or independent filings to be made within three years, whichever comes sooner. The Pennsylvania Companies filed voluntary surcharges on June1, 2018, to adjust rates for the reduced tax rate, which were effective for bills rendered starting July 1, 2018. For the first six-month period, the surcharge is expected to return to customers $19 million for ME, $20 million for PN, $5 million for Penn, and $15 million for WP.

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.

On September 23, 2016, the WVPSC approved the Phase II energy efficiency program for MP and PE as reflected in a unanimous settlement, which includes three energy efficiency programs to meet the Phase II requirement of energy efficiency reductions of 0.5% of 2013 distribution sales for the January 1, 2017 through May 31, 2018 period, which was approved by the WVPSC in the 2012 proceeding approving the transfer of ownership of Harrison Power Station to MP. The costs for the Phase II program are expected to be $10.4 million and are eligible for recovery through the existing energy efficiency rider which is reviewed in the fuel (ENEC) case each year. On December 15, 2017, the WVPSC approved MP's and PE's proposed annual decrease in their EE&C rates, effective January 1, 2018, which decrease is not material to FirstEnergy. This Phase II energy efficiency program ended May 31, 2018.

On December 9, 2016, the WVPSC approved the annual ENEC case for MP and PE as reflected in a unanimous settlement, resulting in an increase in the ENEC rate of $25 million annually beginning January 1, 2017. In addition, ENEC rates will be maintained at the same level for a two-year period. The next ENEC filing is expected to be made by September 1, 2018.

On January 3, 2018, the WVPSC initiated a proceeding to investigate the effects of the Tax Act on the revenue requirements of utilities. MP and PE must track the tax savings resulting from the Tax Act on a monthly basis, effective January 1, 2018. On January 26, 2018, the WVPSC issued an order clarifying that regulatory accounting should be implemented as of January 1, 2018, including the recording of any regulatory liabilities resulting from the Tax Act. MP and PE filed written testimony on May 30, 2018, explaining the impact of the Tax Act on federal income tax and revenue requirements and showing an annual rate impact of $26.2 million. Other parties' testimony was filed on July 2, 2018 and MP and PE filed their rebuttal testimony on July 13, 2018. The WVPSC held evidentiary hearings on July 24-25, 2018.

FERC MATTERS

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, AE Supply, ATSI, MAIT 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, or obligations to upgrade or build transmission facilities, that could have a material adverse effect on its financial condition, results of operations and cash flows.

PJM Transmission Rates

PJM and its stakeholders have been debating the proper method to allocate costs for a certain class of new transmission facilities since 2005. 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. For historical transmission costs prior to January 1, 2016, the settlement agreement provides a “black-box” schedule of credits to and payments from customers across PJM’s transmission zones. From January 1, 2016 forward, PJM will collect a charge for the revenue requirement associated with each transmission enhancement through a “50/50” calculation, with 50% based on a load-ratio share and the other 50% solution-based distribution factor (DFAX) hybrid method. On May 31, 2018, FERC approved the settlement agreement as filed, without conditions. As a result of the settlement, FirstEnergy recorded a pre-tax benefit of approximately $77 million (within the Other operating expenses line on the Consolidated Statement of Income) relating to the amount of refund the Ohio Companies will receive and retain from PJM for the period prior to January 1, 2016. For the period after January 1, 2016, FirstEnergy is currently unable to reasonably estimate the impact until PJM releases the “50/50” allocation factors and FirstEnergy calculates the respective charges and credits. PJM is expected to implement the settlement for transmission service purchased in July 2018 in customer bills beginning in August 2018. Requests for rehearing or clarification of FERC's May 31, 2018, orders and related responses remain pending before FERC.

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, FirstEnergy joined certain other PJM TOs in a protest of MISO's proposal to allocate MVP costs to energy transactions that cross MISO's borders into the PJM Region. On July 13, 2016, FERC issued its order finding it appropriate for MISO to assess an MVP usage charge for transmission exports from MISO to PJM. Various parties, including FirstEnergy and the PJM TOs, requested rehearing or clarification of FERC’s order. The requests for rehearing remain pending before FERC.

In addition, in a May 31, 2011 order, FERC ruled that the costs for certain "legacy RTEP" transmission projects in PJM approved before ATSI joined PJM could be charged to transmission customers in the ATSI zone. The amount to be paid, and the question of derived benefits, will be determined pursuant to the settlement agreement described above under "PJM Transmission Rates."

The outcome of the proceedings that address the remaining open issues related to MVP costs cannot be predicted at this time.

MAIT Transmission Formula Rate

On October 28, 2016, as amended on January 10, 2017, MAIT submitted an application to FERC requesting authorization to implement a forward-looking formula transmission rate to recover and earn a return on transmission assets effective February 1, 2017. Various intervenors submitted protests of the proposed MAIT formula rate. Among other things, the protests asked FERC to suspend the proposed effective date for the formula rate until June 1, 2017. On March 10, 2017, FERC issued an order accepting the MAIT formula transmission rate for filing, suspending the formula transmission rate for five months to become effective July 1, 2017, and establishing hearing and settlement judge procedures. On April 10, 2017, MAIT requested rehearing of FERC’s decision to suspend the effective date of the formula rate. MAIT’s rates went into effect on July 1, 2017, subject to refund pending the outcome of the hearing and settlement procedures. On October 13, 2017, MAIT and certain parties filed a settlement agreement with FERC. The settlement agreement provides for certain changes to MAIT's formula rate, changes MAIT's ROE from 11% to 10.3%, sets the recovery amount for certain regulatory assets, and establishes that MAIT's capital structure will not exceed 60% equity over the period ending December 31, 2021. The settlement agreement further provides that the ROE and the 60% cap on the equity component of MAIT's capital structure will remain in effect unless changed pursuant to section 205 or 206 of the FPA provided the effective date for any change shall be no earlier than January 1, 2022.

On May 21, 2018, FERC issued an order accepting the settlement agreement as filed, without conditions. Refunds for the difference between the filed rate and the settlement rate will be handled through MAIT's true-up process. In compliance with the settlement agreement, on June 15, 2018, MAIT withdrew its April 2017 request for rehearing of FERC’s March 10, 2017 order.

PATH Transmission Project

In 2012, the PJM Board of Managers canceled the PATH project, a proposed transmission line from West Virginia through Virginia and into Maryland. 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 hearing and settlement procedures. On January 19, 2017, FERC issued an order reducing the PATH formula rate ROE from 10.4% to 8.11% effective January 19, 2017 and allowing recovery of certain related costs. On February 21, 2017, PATH filed a request for rehearing with FERC seeking recovery of disallowed costs and requesting that the ROE be reset to 10.4%. The Edison Electric Institute submitted an amicus curiae request for reconsideration in support of PATH. On March 20, 2017, PATH also submitted a compliance filing implementing the January 19, 2017 order. Certain affected ratepayers challenged the compliance filing, and FERC Staff requested additional information on, and edits to, the compliance filing, as directed by the January 19, 2017 order. PATH responded to comments and Staff's request. FERC orders on PATH's requests for rehearing and compliance filing remain pending.

FERC Actions on Tax Act

On March 15, 2018, FERC took action to address the impact of the Tax Act on FERC-jurisdictional rates, including transmission and electric wholesale rates. FERC directed MP, PE and WP to either submit a joint filing to adjust the transmission rate for the Allegheny transmission zone in the PJM Region to address the impact of the Tax Act changes, or to "show cause" as to why such action is not required. FERC established a refund effective date of March 21, 2018 for any refunds as a result of the change in tax rate. On May 14, 2018, MP, PE and WP submitted revisions to their stated transmission rate to reflect the reduction in the federal corporate income tax rate. The revisions reduce the rate by 6.70%. There were no comments submitted in response to the proposed revisions, and the matter is now before FERC for further action. FERC is not at this time requiring other FirstEnergy FERC-jurisdictional companies to make changes to their transmission or wholesale rates. However, these rates may be affected by a related FERC "Notice of Inquiry" assessing the impact of the Tax Act on certain rate components.

Also, on March 15, 2018, FERC issued a Notice of Inquiry seeking information regarding whether and how FERC should address possible changes to accumulated deferred income taxes and bonus depreciation as a result of the Tax Act. Such possible changes could impact FERC-jurisdictional rates, including wholesale rates. Various entities submitted responses to the Notice of Inquiry on May 21, 2018. FESC, on behalf of its transmission owning affiliates, participated in the development of separate comments submitted by Edison Electric Institute and certain PJM TOs. The matter is now before FERC for further action.

PJM Markets: Grid Reliability and Resiliency

On September 28, 2017, the Secretary of Energy released a NOPR requesting FERC to issue rules directing RTOs, including PJM, to incorporate pricing for defined "eligible grid reliability and resiliency resources" into wholesale energy markets. FERC established a docket requesting comments, and issued an order on January 8, 2018 terminating the NOPR proceeding, finding that the NOPR did not satisfy the statutory threshold requirements under the FPA for requiring changes to RTO/ISO tariffs to address resilience concerns. FERC in its order instituted a new administrative proceeding to gather additional information regarding resilience issues. Each RTO/ISO responded to a provided list of questions and various entities submitted comments. The matter is now before FERC for further action. In the event FERC orders resiliency payments in wholesale energy markets, such charges may be levied against LSEs in the PJM Region, including the Utilities. There is no deadline or requirement for FERC to act in this new proceeding and as such the outcome of the proceeding and its impact on the Utilities, if any, cannot be predicted at this time.

PJM Markets: Capacity Pricing Reform

In March 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 PJM capacity markets by state-subsidized generation. However, FERC took no action at that time.

In April 2018, PJM filed with FERC two alternative proposals to modify the PJM Tariff to address concerns that state-authorized subsidies to certain generators within PJM may affect market prices. Under one approach, PJM would establish a two-stage capacity auction to enable subsidized generators to participate in the auction, but to prevent the subsidies from affecting the market clearing price. Under the alternative approach, the MOPR would be expanded to cover all generators in PJM, including vertically-integrated utility generation owners such as MP and JCP&L. PJM requested FERC action on the filing by June 29, 2018, and to make the proposed tariff revisions effective as of January 4, 2019. FESC, on behalf of its affiliates and jointly with EKPC, submitted a protest of PJM's proposals. FESC and EKPC requested FERC reject PJM's proposals, maintain the existing PJM market rules, and direct PJM to develop a holistic solution to the fundamental issues facing its markets. FESC and EKPC submitted that should FERC opt to change PJM's existing MOPR rules, FERC should accept PJM's capacity repricing option subject to additional development pursuant to PJM's stakeholder process. Various other entities also submitted protests and comments.

On June 29, 2018, FERC issued an order rejecting the March 2016 complaint and both of PJM's April 2018 proposals, finding that none of the proposed solutions to MOPR reform were just and reasonable and not unduly discriminatory. FERC established a new FPA Section 206 proceeding to develop a solution to the MOPR construct. FERC's directives in the new proceeding are to revise the MOPR so that it (i) applies to both existing and new resources that receive out-of-market subsidies with very limited exemptions; and (ii) accommodates state policies by allowing a new FRR-like alternative that would remove resources that receive out-of-market subsidies from the capacity market if the unit could be paired with a commensurate amount of load. Resources receiving out-of-market revenues could opt to stay in the capacity market but would be subject to the revised MOPR, or under the FRR-like alternative they could exit the market. FERC established a timeline for comments and expects to issue an order by January 4, 2019, so that the reformed MOPR can be implemented for the 2019 BRA. FERC instituted a refund effective date of July 11, 2018, for the new Section 206 proceeding. On July 30, 2018 FESC, on behalf of the Utilities, submitted a request for clarification or, in the alternative, rehearing of FERC's June 29, 2018 order. Specifically, FESC requested clarification regarding the applicability of FERC's directed MOPR reform to vertically-integrated resources.

On May 31, 2018, certain merchant generators filed a complaint with FERC against PJM seeking an order finding that PJM's existing MOPR mechanism is unjust and unreasonable, and implementing instead a so-called "Clean" MOPR that would apply to existing and new generation resources of all fuel types and all ownership arrangements, including regulated generation resources such as MP's and JCP&L's existing generation, that receive or have any form of "out-of-market" support, including recovery of generation costs in retail rates. The complainants request a FERC order by May 2019, so that the proposed "Clean" MOPR could be implemented in PJM's 2019 BRA. PJM answered the complaint on June 19, 2018, requesting that FERC accept one of PJM's two proposed alternatives (discussed above) instead. FESC, on behalf of its affiliates and jointly with EKPC, submitted a protest of the complaint. FESC and EKPC requested FER reject PJM's proposals, maintain the existing PJM market rules, and direct PJM to develop a holistic solution to the fundamental issues facing its market. FESC and EKPC submitted that should FERC opt to change PJM's existing MOPR rules, FERC should accept PJM's capacity repricing option subject to additional development pursuant to PJM's stakeholder process. Various other entities also submitted protests and comments. FERC did not address the Clean MOPR Complaint in its June 29, 2018 order and, in consequence, the Clean MOPR Complaint remains pending before FERC. The outcome of FERC's Section 206 proceeding and the Clean MOPR Complaint, and their impact on FirstEnergy's regulated generation sources, if any, cannot be predicted at this time.

ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality and other environmental matters. Pursuant to a March 28, 2017 executive order, the EPA and other federal agencies are to review existing regulations that potentially burden the development or use of domestically produced energy resources and appropriately suspend, revise or rescind those that unduly burden the development of domestic energy resources beyond the degree necessary to protect the public interest or otherwise comply with the law. FirstEnergy cannot predict the timing or ultimate outcome of any of these reviews or how any future actions taken as a result thereof, in particular with respect to existing environmental regulations, may impact its business, results of operations, cash flows and financial condition.

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 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 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 the EPA’s regulatory approach under CSAPR, but questioning whether the EPA required upwind states to reduce emissions by more than their contribution to air pollution in downwind states. The EPA issued a CSAPR update rule on September 7, 2016, reducing summertime NOx emissions from power plants in 22 states in the eastern U.S., including Ohio, Pennsylvania and West Virginia, beginning in 2017. Various states and other stakeholders appealed the CSAPR update rule to the D.C. Circuit in November and December 2016. On September 6, 2017, the D.C. Circuit rejected the industry's bid for a lengthy pause in the litigation and set a briefing schedule. Depending on the outcome of the appeals, the EPA’s reconsideration of the CSAPR update rule and how the EPA and the states ultimately implement CSAPR, the future cost of compliance may be material and changes to FirstEnergy's operations may result.

The EPA tightened the primary and secondary NAAQS for ozone from the 2008 standard levels of 75 PPB to 70 PPB on October 1, 2015. The 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 on April 30, 2018, the EPA designated fifty-one areas in twenty-two states as non-attainment; however, FirstEnergy has no power plants operating in those areas. States 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 operations may result. In August 2016, the State of Delaware filed a CAA Section 126 petition with the EPA alleging that the Harrison generating facility's NOx emissions significantly contribute to Delaware's inability to attain the ozone NAAQS. The petition seeks a short-term NOx emission rate limit of 0.125 lb/mmBTU over an averaging period of no more than 24 hours. On September 27, 2016, the EPA extended the time frame for acting on the State of Delaware's CAA Section 126 petition by six months to April 7, 2017, but has not taken any further action. On January 2, 2018, the State of Delaware provided the EPA a notice required at least 60 days prior to filing a suit seeking to compel the EPA to either approve or deny the August 2016 CAA Section 126 petition. In November 2016, the State of Maryland filed a CAA Section 126 petition with the EPA alleging that NOx emissions from 36 EGUs, including Harrison Units 1, 2 and 3 and Pleasants Units 1 and 2, significantly contribute to Maryland's inability to attain the ozone NAAQS. The petition seeks NOx emission rate limits for the 36

EGUs by May 1, 2017. On January 3, 2017, the EPA extended the time frame for acting on the CAA Section 126 petition by six months to July 15, 2017, but has not taken any further action. On September 27, 2017, and October 4, 2017, the State of Maryland and various environmental organizations filed complaints in the U.S. District Court for the District of Maryland seeking an order that the EPA either approve or deny the CAA Section 126 petition of November 16, 2016. On May 31, 2018, the EPA proposed to deny both the States of Delaware and Maryland petitions under CAA Section 126. In March 2018, the State of New York filed a CAA Section 126 petition with the EPA alleging that NOx emissions from nine states (including Ohio, Pennsylvania and West Virginia) significantly contribute to New York’s inability to attain the ozone NAAQS. The petition seeks suitable emission rate limits for large stationary sources that are affecting New York’s air quality within the three years allowed by CAA Section 126. On May 3, 2018, the EPA extended the time frame for acting on the CAA Section 126 petition by six months to November 9, 2018. FirstEnergy is unable to predict the outcome of these matters or estimate the loss or range of loss.

On May 1, 2017, FE and FG and CSX and BNSF entered into a definitive settlement agreement, which resolved all claims related to a coal transportation contract dispute as a result of MATS on the terms and conditions set forth below. Pursuant to the settlement agreement, FG agreed to pay CSX and BNSF an aggregate amount equal to $109 million, payable in three annual installments, the first of which was made on May 1, 2017. FE agreed to unconditionally and continually guarantee the settlement payments due by FG pursuant to the terms of the settlement agreement. The settlement agreement further provided that in the event of the initiation of bankruptcy proceedings or failure to make timely settlement payments, the unpaid settlement amount will immediately accelerate and become due and payable in full. On April 6, 2018, FE paid the remaining $72 million under the settlement agreement as a result of the FES Bankruptcy.

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. On June 23, 2014, the U.S. Supreme Court decided that CO_2 or other GHG emissions alone cannot trigger permitting requirements under the CAA, but that air emission sources that need PSD permits due to other regulated air pollutants can be required by the EPA to install GHG control technologies. The EPA released its final CPP regulations in August 2015 (which have been stayed by the U.S. Supreme Court), to reduce CO_2 emissions from existing fossil fuel-fired EGUs. The EPA also finalized separate regulations imposing CO_2 emission limits for new, modified, and reconstructed fossil fuel fired EGUs. Numerous states and private parties filed appeals and motions to stay the CPP with the D.C. Circuit in October 2015. On January 21, 2016, 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. On March 28, 2017, an executive order, entitled “Promoting Energy Independence and Economic Growth,” instructed the EPA to review the CPP and related rules addressing GHG emissions and suspend, revise or rescind the rules if appropriate. On October 16, 2017, the EPA issued a proposed rule to repeal the CPP. Depending on the outcomes of the review pursuant to the executive order, 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 GHG emissions by 26 to 28 percent below 2005 levels by 2025, and in September 2016, joined in adopting the agreement reached on December 12, 2015, at the United Nations Framework Convention on Climate Change meetings in Paris. The Paris Agreement was ratified by the requisite number of countries (i.e., at least 55 countries representing at least 55% of global GHG emissions) in October 2016 and its non-binding obligations to limit global warming to well below two degrees Celsius became effective on November 4, 2016. On June 1, 2017, the Trump Administration announced that the U.S. would cease all participation in the Paris Agreement. 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.

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 facilities. 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. Depending on any final action taken by the states with respect to impingement and entrainment, the future capital costs of compliance with these standards may be material.

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 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. On April 13, 2017, the EPA granted a Petition for Reconsideration and administratively stayed (effective upon publication in the Federal Register) all deadlines in the effluent limits rule pending a new rulemaking. Also, on September 18, 2017, the EPA postponed certain compliance deadlines for two years. 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 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. In March 2018, the WVDEP issued a draft NPDES Permit Renewal that, if finalized as proposed, would moot the appeal and reduce the estimated capital investment requirements. 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 CCRs, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation.

In April 2015, the EPA finalized regulations for the disposal of CCRs (non-hazardous), establishing national standards for 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. On September 13, 2017, the EPA announced that it would reconsider certain provisions of the final regulations. On July 17, 2018, the EPA Administrator signed a final rule extending the deadline for certain CCR facilities to cease disposal and commence closure activities, as well as, establishing less stringent groundwater monitoring and protection requirements. Based on an assessment of the finalized regulations, the future cost of compliance and expected timing had no significant impact on FirstEnergy's existing AROs associated with CCRs. Although not currently expected, changes in timing and closure plan requirements in the future could materially and adversely impact FirstEnergy's AROs.

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, 2018, based on estimates of the total costs of cleanup, FirstEnergy's proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately $116 million have been accrued through June 30, 2018. Included in the total are accrued liabilities of approximately $78 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. FE 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, JCP&L, ME and PN must ensure that adequate funds will be available to decommission their retired nuclear facility, TMI-2. As of June 30, 2018, JCP&L, ME and PN had approximately $0.8 billion invested in external trusts to be used for the decommissioning and environmental remediation of their retired TMI-2 nuclear generating facility. The values of these NDTs also fluctuate based on market conditions. If the values of the trusts decline by a material amount, the obligation of JCP&L, ME, and PN 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.

FES Bankruptcy

On March 31, 2018, FES, including its consolidated subsidiaries, FG, NG, FE Aircraft Leasing Corp., Norton Energy Storage L.L.C. and FirstEnergy Generation Mansfield Unit 1 Corp, and FENOC filed voluntary petitions for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code in the Bankruptcy Court. See Note 3, "Discontinued Operations," for additional information.

Other Legal Matters

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to FirstEnergy's normal business operations pending against FE or its subsidiaries. The loss or range of loss in these matters is not expected to be material to FE or its subsidiaries. The other potentially material items not otherwise discussed above are described under Note 13, "Regulatory Matters."

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 FE 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 FE's or its subsidiaries' financial condition, results of operations and cash flows.

NEW ACCOUNTING PRONOUNCEMENTS

Recently Adopted Pronouncements

ASU 2014-09, "Revenue from Contracts with Customers" (Issued May 2014 and subsequently updated to address implementation questions): The new revenue recognition guidance establishes a new control-based revenue recognition model, changes the basis for deciding when revenue is recognized over time or at a point in time, provides new and more detailed guidance on specific topics and expands and improves disclosures about revenue. FirstEnergy evaluated its revenues and the new guidance had immaterial impacts to recognition practices upon adoption on January 1, 2018. As part of the adoption, FirstEnergy elected to apply the new guidance on a modified retrospective basis. FirstEnergy did not record a cumulative effect adjustment to retained earnings for initially applying the new guidance as no revenue recognition differences were identified in the timing or amount of revenue. In addition, upon adoption, certain immaterial financial statement presentation changes were implemented. See Note 2, " Revenue," for additional information on FirstEnergy revenues.

ASU 2016-01, "Financial Instruments-Overall: Recognition and Measurement of Financial Assets and Financial Liabilities" (Issued January 2016 and subsequently updated in 2018): ASU 2016-01 primarily affects the accounting for equity investments, financial liabilities under the fair value option, and the presentation and disclosure requirements for financial instruments. FirstEnergy adopted this standard on January 1, 2018, and recognizes all gains and losses for equity securities in income with the exception of those that are accounted for under the equity method of accounting. The NDT equity portfolios of JCP&L, ME and PN will not be impacted as unrealized gains and losses will continue to be offset against regulatory assets or liabilities. As a result of adopting this standard, FirstEnergy recorded a cumulative effect adjustment to retained earnings of $115 million (pre-tax) on January 1, 2018, representing unrealized gains on equity securities with FES NDTs that were previously recorded to AOCI. Following deconsolidation of FES and FENOC, the adoption of this standard is not expected to have a material impact on FirstEnergy's financial statements as the majority of its equity securities are offset against a regulatory asset or liability.

ASU 2016-18, "Restricted Cash" (Issued November 2016): ASU 2016-18 addresses the presentation of changes in restricted cash and restricted cash equivalents in the statement of cash flows. The guidance is required to be applied retrospectively. As a result of adopting this standard, FirstEnergy's statement of cash flows reports changes in the total of cash, cash equivalents, restricted cash and restricted cash equivalents. Prior periods have been recast to conform to the current year presentation.

ASU 2017-01, "Business Combinations: Clarifying the Definition of a Business" (Issued January 2017): ASU 2017-01 assists entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. FirstEnergy adopted ASU 2017-01 on January 1, 2018. The ASU will be applied prospectively to future transactions.

ASU 2017-04, "Goodwill Impairment" (Issued January 2017): ASU 2017-04 simplifies the accounting for goodwill impairment by removing Step 2 of the current test, which requires calculation of a hypothetical purchase price allocation. Under the revised guidance, goodwill impairment will be measured as the amount by which a reporting unit's carrying value exceeds its fair value, not to exceed the carrying amount of goodwill (currently Step 1 of the two-step impairment test). Entities will continue to have the option to perform a qualitative assessment to determine if a quantitative impairment test is necessary. FirstEnergy has elected to early adopt ASU 2017-04 as of January 1, 2018, and will apply this standard on a prospective basis.
ASU 2017-07, "Compensation-Retirement Benefits: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost" (Issued March 2017): ASU 2017-07 requires entities to retrospectively (1) disaggregate the current-service-cost component from the other components of net benefit cost (the other components) and present it with other current compensation costs for related employees in the income statement and (2) present the other components elsewhere in the income statement and outside of income from operations if such a subtotal is presented. In addition, only service costs are eligible for

capitalization on a prospective basis. FirstEnergy adopted ASU 2017-07 on January 1, 2018. Because the non-service cost components of net benefit cost are no longer eligible for capitalization after December 31, 2017, FirstEnergy has recognized these components in income as a result of adopting this standard. FirstEnergy reclassified approximately $8 million and $16 million of non-service costs from Other operating expense to Miscellaneous income for the three and six months ended June 30, 2017, respectively.

ASU 2018-02, "Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income" (Issued February 2018): ASU 2018-02 allows entities to reclassify from AOCI to retained earnings stranded tax effects resulting from the Tax Act. FirstEnergy early adopted this standard during the first quarter of 2018 and has elected to present the change in the period of adoption. Upon adoption, FirstEnergy recorded a $22 million cumulative effect adjustment for stranded tax effects, such as pension and OPEB prior service costs and losses on derivative hedges, to retained earnings on January 1, 2018, of which $8 million was related to FES and FENOC.

ASU 2018-05, "Income Taxes (Topic 740): Amendments to SEC Paragraphs Pursuant to SEC Staff Accounting Bulletin No. 118" (Issued March 2018): ASU 2018-05, effective 2018, expands income tax accounting and disclosure guidance to include SAB 118 issued by the SEC in December 2017. SAB 118 provides guidance on accounting for the income tax effects of the Tax Act and among other things allows for a measurement period not to exceed one year for companies to finalize the provisional amounts recorded as of December 31, 2017. See Note 7, "Income taxes," for additional information on FirstEnergy's accounting for the Tax Act.

Recently Issued Pronouncements - The following new authoritative accounting guidance issued by the FASB has not yet been adopted. Unless otherwise indicated, FirstEnergy is currently assessing the impact such guidance may have on its financial statements and disclosures, as well as the potential to early adopt where applicable. FirstEnergy has assessed other FASB issuances of new standards not described below or in the 2017 Annual Report on Form 10-K based upon the current expectation that such new standards will not significantly impact FirstEnergy's financial reporting. Below is an update to the discussion of pronouncements contained in the 2017 Annual Report on Form 10-K.

ASU 2016-02, "Leases (Topic 842)" (Issued February 2016 and subsequently updated to address implementation questions): The new guidance 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. There is an optional transition practical expedient that, if elected, would not require an entity to reconsider its accounting for existing land easements that are not currently accounted for as leases under the current leases guidance. In addition, new qualitative and quantitative disclosures of the amounts, timing, and uncertainty of cash flows arising from leases will be required. The guidance 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 lessors and lessees to recognize and measure leases at the beginning of the earliest period presented (January 1, 2017) or initially apply the requirements of the standard in the period of adoption (January 1, 2019). Any leases that expire before the initial application date will not require any accounting adjustment. FirstEnergy does not plan to adopt these standards early. FirstEnergy expects an increase in assets and liabilities; however, it is currently assessing the impact, including monitoring utility industry implementation guidance, but expects no impact to results of operations or cash flows. FirstEnergy continues to develop its complete lease inventory, as well as identify, assess and document technical accounting issues, policy considerations, financial reporting implications and changes to internal controls and processes. In addition, FirstEnergy is in the process of implementing a third-party software tool that will assist with the initial adoption and ongoing compliance.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See “First Energy Corp. 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, with the participation of the Chief Executive Officer and Chief Financial Officer, have reviewed and evaluated the effectiveness of its disclosure controls and procedures, as defined under the Securities Exchange Act of 1934, as amended, in 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 FirstEnergy have concluded that its 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, 2018, there were no changes in internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934) that have materially affected, or are reasonably likely to materially affect, FirstEnergy's 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 13, "Regulatory Matters," and Note 14, "Commitments, Guarantees and Contingencies," of the Notes to Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q.

ITEM 1A. RISK FACTORS

We operate in a business environment that involves significant risks, many of which are beyond our control. Management of FirstEnergy regularly evaluates the most significant risks of its businesses and reviews those risks with the Board of Directors or appropriate Committees of such Board. The following risk factors and all other information contained in this report should be considered carefully when evaluating FirstEnergy. These risk factors could affect our financial results and cause such results to differ materially from those expressed in any forward-looking statements made by or on behalf of us. Below, we have identified risks we consider material. Additional information on risk factors is included in “Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations,” and in other sections of this Form 10-Q that include forward-looking and other statements involving risks and uncertainties that could impact our business and financial results. The Risk Factors set forth in this Quarterly Report on Form 10-Q supersede in their entirety the Risk Factors contained in our Annual Report on Form 10-K for the fiscal year ended December 31, 2017, filed with the SEC on February 20, 2018, and the Risk Factors contained in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2018, filed with the SEC on April 23, 2018.

Risks Related to the FES Bankruptcy and Remaining Competitive Generation

We Are Subject to Risks Relating to the FES Bankruptcy

As previously disclosed, FES and FENOC (collectively, the Filing Entities) filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code to facilitate an orderly restructuring. It is possible that as part of the restructuring process, claims may be asserted by or on behalf of the Filing Entities against non-debtor affiliates of the Filing Entities. Any assertions of claims by creditors of the Filing Entities against FirstEnergy may require significant effort, resources, and money to defend or could result in material losses to FirstEnergy. We can provide no assurance that any such claims, if asserted, will be resolved in an efficient manner or a manner that is satisfactory to FirstEnergy.

On July 31, 2018, FirstEnergy reached an updated agreement in principle with two groups of key FES creditors in the FES Bankruptcy with whom FirstEnergy had previously reached an agreement in principle in April 2018 while also adding FES, FENOC, and the UCC as parties to such agreement in principle. The settlement will be subject to approval by the FE, FES, FENOC and AE Supply Boards of Directors, the execution of definitive agreements and the approval of the Bankruptcy Court. Additionally, the Bruce Mansfield certificate holders' support for the agreement is subject to and conditioned upon the ultimate implementation of the agreed upon treatment of certain claims of the Bruce Mansfield certificate holders. There can be no assurance that a definitive settlement agreement will be finalized and approved by the Bankruptcy Court and, even if approved, whether the conditions to such settlement will be satisfied, and the actual outcome of this matter may differ materially from the terms of the agreement in principle.

There Is Substantial Uncertainty Regarding the FES Bankruptcy, Which Could Have a Material Adverse Impact on FirstEnergy’s Business, Financial Condition, Results of Operations and Cash Flows

Management of FirstEnergy may be required to spend a significant amount of time and effort dealing with the FES Bankruptcy instead of focusing on FirstEnergy’s business operations, which could have an adverse impact on our ability to execute our business plan and operations. Additionally, FirstEnergy’s relationship with its employees, suppliers, customers and other parties may be adversely impacted by negative publicity related to the FES Bankruptcy or otherwise and FirstEnergy’s operations could be materially and adversely affected. The FES Bankruptcy also may make it more difficult to retain, attract or replace management and other key personnel.

In addition, the FES Bankruptcy creates substantial uncertainty regarding certain significant commercial and other relationships among FE, the Filing Entities and other FE subsidiaries, including, but not limited to, AE Supply. These relationships include a shared services agreement, cash management, intercompany loans, tax sharing and energy-related purchases and sales, among others, which may be subject to review and possible challenge in the FES Bankruptcy. FirstEnergy is unable to estimate the outcome of such challenges or other claims arising out of the FES Bankruptcy, any resulting material losses, obligations or other liabilities of FirstEnergy or their possible material adverse effect on the business, results of operations and financial condition of FirstEnergy.

The costs of potential liabilities resulting from the FES Bankruptcy could have a material and adverse impact on FirstEnergy’s business, financial condition, results of operations and cash flows.

The FES Bankruptcy Could Negatively Impact FirstEnergy’s Right to Repayment under the Intercompany Loans and Other Financial Arrangements

FE has loaned $500 million to FES, has provided additional credit support to FES of up to $200 million and has guaranteed certain material financial obligations of the Filing Entities. Additionally, AE Supply has separately loaned $102 million to FES. There can be no assurance that the loans made by FirstEnergy will be repaid or that FirstEnergy will be reimbursed for any guaranteed obligations it satisfies. Any of these matters could adversely affect the financial condition, cash flows and ability to satisfy obligations of FirstEnergy. In addition, the uncertainty associated with these matters could adversely affect FirstEnergy’s ability to access the capital or credit markets and ability to finance its business.

Adverse Developments Related to the Filing Entities Could Trigger Events of Default under Certain FirstEnergy Obligations

FirstEnergy's credit facilities contain various events of default, including with respect to the borrowers or significant subsidiaries (each as defined in the credit agreements), a bankruptcy or insolvency of FirstEnergy, the failure to pay any principal of or premium or interest on any indebtedness in excess of $100 million, or the failure to satisfy any judgment or order for the payment of money exceeding any applicable insurance coverage by more than $100 million. Although the Filing Entities are not “significant subsidiaries” for these purposes, it is possible that an adverse development related to the Filing Entities could otherwise trigger an event of default under the FirstEnergy credit facilities if creditors of the Filing Entities asserted successful claims against FE or our significant subsidiaries.

In the FES Bankruptcy, the Value of the Collateral Securing the Secured Indebtedness of the Filing Entities May Not Be Sufficient to Ensure Repayment of Such Indebtedness and, the Ability of Holders of Such Indebtedness, Including FE, to Realize Any Such Value May Be Delayed or Otherwise Limited

The FES Bankruptcy will affect the Filing Entities’ respective properties and assets that serve as collateral securing certain of the Filing Entities’ secured indebtedness. As a result, the value of the collateral securing such indebtedness or the net proceeds from any sale or liquidation of such collateral, as applicable, may not be sufficient to pay the obligations under such secured indebtedness, including amounts owed to FE under the FES secured credit agreement. If the value of the collateral or the net proceeds of any sale of such collateral, as applicable, are not sufficient to repay all amounts due with respect to such secured indebtedness, the holders of the secured indebtedness would have an unsecured claim for the deficiency in value or proceeds against the applicable obligors alongside all other unsecured creditors of such obligor. None of the Filing Entities can assure holders of their respective secured debt that, if a sale process were to be pursued, the collateral will be salable or, if salable, that there will not be substantial delays in its sale due to, among other things, the need for regulatory authorization from the FERC, NRC or other governmental authorities, as applicable.

Additionally, the holders of the secured indebtedness, including FE, may not be able or entitled to receive payment of interest, fees (including attorney's fees), costs or charges related to such secured obligations, and may be required to repay any such amounts received by such holders during the FES Bankruptcy.

Regardless of the Viability or Success of the Sale of Certain AE Supply Generation Assets, Certain Events May Significantly Increase Cash Flow and Liquidity Risks and Have a Material Adverse Effect on Results of Operations and the Financial Condition of FirstEnergy

Any developments that negatively impact the viability or success of the sale of the remaining AE Supply generation assets could have adverse consequences, including:

- the risk that we may not be able to complete our planned disposition of our remaining competitive generation assets;
- the risk that FirstEnergy could be required to satisfy or otherwise elect to guarantee significant financial obligations related to such sales, which could adversely affect the financial condition and cash flows of FirstEnergy; and
- the risk that AE Supply is unable to adequately address the capacity coverage risk for shutting Pleasants Power Station down early.

Further, as part of AE Supply’s recent sale of gas generation assets to a subsidiary of LS Power, FE provided two limited three-year guarantees totaling $555 million of certain obligations of AE Supply and AGC arising under the purchase agreement. Liabilities incurred under these guarantees could have an adverse impact on the financial condition of FE.

Risks Related to Business Operations Generally

If Our "FE Tomorrow" Organizational Realignment Plans Do Not Achieve the Expected Benefits, There Could Be Negative Impacts to FirstEnergy's Business, Results of Operations and Financial Condition

In support of the strategic review to exit competitive generation, management launched the FE Tomorrow initiative to define FirstEnergy's future organization to support its regulated business. FE Tomorrow is intended to align corporate services to efficiently support the regulated operations by ensuring that FirstEnergy has the right talent, organizational and cost structure to achieve our earnings growth targets. In support of the FE Tomorrow initiative, in June and early July 2018, nearly 500 employees in the shared services and utility services and sustainability organizations, which was more than 80% of the eligible employees, accepted a voluntary enhanced retirement package, which included severance compensation and a temporary pension enhancement, with most employees departing by December 31, 2018. FirstEnergy expects further talent, organizational and cost structure adjustments in order to accomplish the FE Tomorrow goals. Management expects the cost savings resulting from the FE Tomorrow initiative to support the company's growth targets. There can be no assurance that these organizational changes will result in the anticipated benefits to FirstEnergy's business, results of operations and financial condition in a timely manner if at all.

Our ability to achieve the anticipated cost savings and other benefits from FE Tomorrow within the expected time frame is subject to many estimates and assumptions. These estimates and assumptions are subject to significant economic, competitive and other uncertainties, some of which are beyond our control. Further, during and following completion of FE Tomorrow, FirstEnergy could experience unexpected delays in and business disruptions resulting from supporting these initiatives, decreased productivity, higher than anticipated costs, adverse effects on employee morale and employee turnover, including the possible loss of valuable employees, any of which may impair our ability to achieve anticipated results or otherwise harm FirstEnergy's business, results of operations and financial condition.

Temperature Variations as well as Weather Conditions or other Natural Disasters Could Have an Adverse Impact on Our Results of Operations and Financial Condition, and Demand Significantly Below or Above Our Forecasts Could Adversely Affect Our Energy Margins and Have an Adverse Effect on our Financial Condition and Results of Operations

Weather conditions directly influence the demand for electric power. Demand for power generally peaks during the summer and winter months, with market prices also typically peaking at that time. Overall operating results may fluctuate based on weather conditions. In addition, we have historically sold less power, and consequently received less revenue, when weather conditions are milder. Severe weather, such as tornadoes, hurricanes, ice or snowstorms, or droughts or other natural disasters, may cause outages and property damage that may require us to incur additional costs that are generally not insured and that may not be recoverable from customers. The effect of the failure of our facilities to operate as planned under these conditions would be particularly burdensome during a peak demand period and could have an adverse effect on our financial condition and results of operations.

We Are Subject to Financial Performance Risks Related to Regional and General Economic Cycles and also Related to Heavy Industries such as Shale Gas, Automotive and Steel

Our business follows economic cycles. Economic conditions impact the demand for electricity and declines in the demand for electricity will reduce our revenues. The regional economy in which our Utilities operate is influenced by conditions in industries in our business territories, e.g. shale gas, automotive, chemical, steel and other heavy industries, and as these conditions change, our revenues will be impacted.

Certain FirstEnergy Companies May Not Be Able to Meet Their Obligations to or on Behalf of Other FirstEnergy Companies or Their Affiliates, Which Could Have a Material Adverse Effect on the Results of Operations, Financial Condition or Liquidity of One or More FirstEnergy Entities

Certain of the FirstEnergy companies have obligations to other FirstEnergy companies pursuant to transactions involving credit, energy, coal, services and hedging transactions. If one FirstEnergy entity failed to perform under any of these arrangements, other FirstEnergy entities could incur losses. Their results of operations, financial position, or liquidity could be adversely affected, and such non-performance could result in the non-defaulting FirstEnergy entity being unable to meet its obligations to unrelated third parties. Certain FirstEnergy companies also provide guarantees to third-party creditors on behalf of other FirstEnergy affiliate companies under transactions of the types described above, legal settlements or under financing transactions. Any failure to perform under such guarantees by such FirstEnergy guarantor company or under the underlying transaction by the FirstEnergy company on whose behalf the guarantee was issued could have similar adverse impacts on one or both FirstEnergy companies or their affiliates.

We Are Subject to Risks Arising from the Operation of Our Power Plants and Transmission and Distribution Equipment Which Could Reduce Revenues, Increase Expenses and Have a Material Adverse Effect on Our Business, Financial Condition and Results of Operations

Operation of generation, transmission and distribution facilities involves risk, including the risk of potential breakdown or failure of equipment or processes due to aging infrastructure, fuel supply or transportation disruptions, accidents, labor disputes or work stoppages by employees, human error in operations or maintenance, acts of terrorism or sabotage, construction delays or cost overruns, shortages of or delays in obtaining equipment, material and labor, operational restrictions resulting from environmental requirements and governmental interventions, and performance below expected levels. In addition, weather-related incidents and other natural disasters can disrupt generation, transmission and distribution delivery systems. Because our transmission facilities are interconnected with those of third parties, the operation of our facilities could be adversely affected by unexpected or uncontrollable events occurring on the systems of such third parties.

Operation of our power plants below expected capacity could result in lost revenues and increased expenses, including higher operation and maintenance costs, purchased power costs and capital requirements. Unplanned outages of generating units and extensions of scheduled outages due to mechanical failures or other problems occur from time to time and are an inherent risk of our business. Unplanned outages typically increase our operation and maintenance expenses or may require us to incur significant costs as a result of operating our higher cost units or obtaining replacement power from third parties in the open market to satisfy our sales obligations. Moreover, if we were unable to perform under contractual obligations, including, but not limited to, our coal and coal transportation contracts, penalties or liability for damages could result, which could have a material adverse effect on our business, financial condition and results of operations.

Failure to Provide Safe and Reliable Service and Equipment Could Result in Serious Injury or Loss of Life That May Harm Our Business Reputation and Adversely Affect Our Operating Results

We are obligated to provide safe and reliable service and equipment in our franchised service territories. Meeting this commitment requires the expenditure of significant capital resources. However, our employees, contractors and the general public may be exposed to dangerous environments due to the nature of our operations. Failure to provide safe and reliable service and equipment due to various factors, including equipment failure, accidents and weather, could result in serious injury or loss of life that may harm our business reputation and adversely affect our operating results through reduced revenues, increased capital and operating costs, litigation or the imposition of penalties/fines or other adverse regulatory outcomes.

Our Use of Non-Derivative and Derivative Contracts to Mitigate Risks Could Result in Financial Losses That May Negatively Impact Our Financial Results

We use a variety of non-derivative and derivative instruments, such as swaps, options, futures and forwards, to manage our commodity and financial market risks. In the absence of actively quoted market prices and pricing information from external sources, the valuation of some of these derivative instruments involves management’s judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of some of these contracts. Also, we could recognize financial losses as a result of volatility in the market value of these contracts if a counterparty fails to perform or if there is limited liquidity of these contracts in the market.

The Outcome of Litigation, Arbitration, Mediation, and Similar Proceedings Involving Our Business, or That of One or More of Our Operating Subsidiaries, Is Unpredictable and an Adverse Decision in Any Material Proceeding Could Have a Material Adverse Effect on Our Financial Condition and Results of Operations

We are involved in a number of litigation, arbitration, mediation, and similar proceedings. These and other matters may divert financial and management resources that would otherwise be used to benefit our operations. Further, no assurances can be given that the resolution of these matters will be favorable to us. If certain matters were ultimately resolved unfavorably to us, the results of operations and financial condition of FirstEnergy could be materially adversely impacted.

In addition, we are sometimes subject to investigations and inquiries by various state and federal regulators due to the heavily regulated nature of our industry. Any material inquiry or investigation could potentially result in an adverse ruling against us, which could have a material adverse impact on our financial condition and operating results.

Capital Market Performance and Other Changes May Decrease the Value of Pension Fund Assets and Other Trust Funds, Which Could Require Significant Additional Funding and Negatively Impact Our Results of Operations and Financial Condition

Our financial statements reflect the values of the assets held in trust to satisfy our obligations to decommission our retired nuclear generating facility and under pension and other postemployment benefit plans. Certain of the assets held in these trusts do not have readily determinable market values. Changes in the estimates and assumptions inherent in the value of these assets could affect the value of the trusts. If the value of the assets held by the trusts declines by a material amount, our funding obligation to the trusts could materially increase. These assets are subject to market fluctuations and will yield uncertain returns, which may fall below our projected return rates. Forecasting investment earnings and costs to decommission FirstEnergy's retired nuclear generating facility, to pay future pension and other obligations, requires significant judgment and actual results may differ significantly from current estimates. Capital market conditions that generate investment losses or that negatively impact the discount rate and increase the present value of liabilities may have significant impacts on the value of the decommissioning, pension and other trust funds, which could require significant additional funding and negatively impact our results of operations and financial position.

We Could be Subject to Higher Costs and/or Penalties Related to Mandatory Reliability Standards Set by NERC/FERC or Changes in the Rules of Organized Markets

Owners, operators, and users of the bulk electric system are subject to mandatory reliability standards promulgated by NERC and approved by FERC. The standards are based on the functions that need to be performed to ensure that the bulk electric system operates reliably. NERC, RFC and FERC can be expected to continue to refine existing reliability standards as well as develop and adopt new reliability standards. Compliance with modified or new reliability standards may subject us to higher operating costs and/or increased capital expenditures. If we were found not to be in compliance with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties. FERC has authority to impose penalties up to and including $1 million per day for failure to comply with these mandatory electric reliability standards.

In addition to direct regulation by FERC, we are also subject to rules and terms of participation imposed and administered by various RTOs and ISOs. Although these entities are themselves ultimately regulated by FERC, they can impose rules, restrictions and terms of service that are quasi-regulatory in nature and can have a material adverse impact on our business. For example, the independent market monitors of ISOs and RTOs may impose bidding and scheduling rules to curb the perceived potential for exercise of market power and to ensure the markets function appropriately. Such actions may materially affect our ability to sell, and the price we receive for, our energy and capacity. In addition, PJM may direct our transmission-owning affiliates to build new transmission facilities to meet PJM's reliability requirements or to provide new or expanded transmission service under the PJM Tariff.

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

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

As a member of an RTO, we are subject to certain additional risks, including those associated with the allocation among members of losses caused by unreimbursed defaults of other participants in that RTO’s market and those associated with complaint cases filed against the RTO that may seek refunds of revenues previously earned by its members.

We Face Certain Human Resource Risks Associated with Potential Labor Disruptions and/or With the Availability of Trained and Qualified Labor to Meet Our Future Staffing Requirements

We are continually challenged to find ways to balance the retention of our aging skilled workforce while recruiting new talent to mitigate losses in critical knowledge and skills due to retirements. Additionally, a significant number of our physical workforce are represented by unions. While we believe that our relations with our employees are generally fair, we cannot provide assurances that the company will be completely free of labor disruptions such as work stoppages, work slowdowns, union organizing campaigns, strikes, lockouts or that any labor disruption will be favorably resolved. Mitigating these risks could require additional financial commitments and the failure to prevent labor disruptions and retain and/or attract trained and qualified labor could have an adverse effect on our business.

Significant Increases in Our Operation and Maintenance Expenses, Including Our Health Care and Pension Costs, Could Adversely Affect Our Future Earnings and Liquidity

We continually focus on limiting, and reducing where possible, our operation and maintenance expenses. However, we expect to continue to face increased cost pressures related to operation and maintenance expenses, including in the areas of health care and pension costs. We have experienced health care cost inflation in recent years, and we expect our cash outlay for health care costs, including prescription drug coverage, to continue to increase despite measures that we have taken requiring employees and retirees to bear a higher portion of the costs of their health care benefits. The measurement of our expected future health care and pension obligations and costs is highly dependent on a variety of assumptions, many of which relate to factors beyond our control. These assumptions include investment returns, interest rates, discount rates, health care cost trends, benefit design changes, salary increases, the demographics of plan participants and regulatory requirements. While we anticipate that our operation and maintenance expenses will continue to increase, if actual results differ materially from our assumptions, our costs could be significantly higher than expected which could adversely affect our future earnings and liquidity.

Our Results May be Adversely Affected by the Volatility in Pension and OPEB Expenses

FirstEnergy recognizes in income the change in the fair value of plan assets and net actuarial gains and losses for its defined Pension and OPEB plans. This adjustment is recognized in the fourth quarter of each year and whenever a plan is determined to qualify for a remeasurement, which could result in greater volatility in pension and OPEB expenses and may materially impact our results of operations.

FirstEnergy recognizes as a pension and OPEB mark-to-market adjustment the change in the fair value of plan assets and net actuarial gains or losses for its pension and OPEB plans in the fourth quarter of each fiscal year and whenever a plan is determined to qualify for a remeasurement.

Cyber-Attacks, Data Security Breaches and Other Disruptions to Our Information Technology Systems Could Compromise Our Business Operations, Critical and Proprietary Information and Employee and Customer Data, Which Could Have a Material Adverse Effect on Our Business, Financial Condition and Reputation

In the ordinary course of our business, we depend on information technology systems that utilize sophisticated operational systems and network infrastructure to run all facets of our generation, transmission and distribution services. Additionally, we store 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 secure maintenance of information and information technology systems is critical to our operations.

Over the last several years, there has been an increase in the frequency of cyber-attacks by terrorists, hackers, international activist organizations, countries and individuals. These and other unauthorized parties may attempt to gain access to our network systems or facilities, or those of third parties with whom we do business in many ways, including directly through our network infrastructure or through fraud, trickery, or other forms of deceiving our employees, contractors and temporary staff. Additionally, our information and information technology systems may be increasingly vulnerable to data security breaches, damage and/or interruption due to viruses, human error, malfeasance, faulty password management or other malfunctions and disruptions. Further, hardware, software, or applications we develop or procure from third parties may contain defects in design or manufacture or other problems that could unexpectedly compromise information and/or security.

Despite security measures and safeguards we have employed, including certain measures implemented pursuant to mandatory NERC Critical Infrastructure Protection standards, our infrastructure may be increasingly vulnerable to such attacks as a result of the rapidly evolving and increasingly sophisticated means by which attempts to defeat our security measures and gain access to our information technology systems may be made. Also, we may be at an increased risk of a cyber-attack and/or data security breach due to the nature of our business.

Any such cyber-attack, data security breach, damage, interruption and/or defect could: (i) disable our generation, transmission (including our interconnected regional transmission grid) and/or distribution services for a significant period of time; (ii) delay development and construction of new facilities or capital improvement projects; (iii) adversely affect our customer operations; (iv) corrupt data; and/or (v) result in unauthorized access to the information stored in our data centers and on our networks, including, company proprietary information, supplier information, employee data, and personal customer data, causing the information to be publicly disclosed, lost or stolen or result in incidents that could result in economic loss and liability and harmful effects on the environment and human health, including loss of life. Additionally, because our generation, transmission and distribution services are part of an interconnected system, disruption caused by a cybersecurity incident at another utility, electric generator, RTO, or commodity supplier could also adversely affect our operations.

Although we maintain cyber insurance and property and casualty insurance, there can be no assurance that liabilities or losses we may incur, including as a result of cybersecurity-related litigation, will be covered under such policies or that the amount of insurance will be adequate. Further, as cyber threats become more difficult to detect and successfully defend against, there can be no assurance that we can implement adequate preventive measures, accurately assess the likelihood of a cyber-incident or quantify potential liabilities or losses. Also, we may not discover any data security breach and loss of information for a significant period of time after the data security breach occurs.

For all of these reasons, any such cyber incident could result in significant lost revenue, the inability to conduct critical business functions and serve customers for a significant period of time, the use of significant management resources, legal claims or proceedings, regulatory penalties, significant remediation costs, increased regulation, increased capital costs, increased protection costs for enhanced cybersecurity systems or personnel, damage to our reputation and/or the rendering of our internal controls ineffective, all of which could materially adversely affect our business and financial condition.

Our Risk Management Policies Relating to Energy and Fuel Prices, and Counterparty Credit, Are by Their Very Nature Subject to Uncertainties, and We Could Suffer Economic Losses Resulting in an Adverse Effect on Results of Operations Despite Our Efforts to Manage and Mitigate Our Risks

We attempt to mitigate the market risk inherent in our energy, fuel and debt positions. Procedures have been implemented to enhance and monitor compliance with our risk management policies, including validation of transaction and market prices, verification of risk and transaction limits, sensitivity analysis and daily portfolio reporting of various risk measurement metrics. Nonetheless, we cannot economically hedge all of our exposure in these areas and our risk management program may not operate as planned. As a result, actual events may lead to greater losses or costs than our risk management positions were intended to hedge.

We Have Coal-Fired Generation Capacity, Which Exposes Us to Risk from Regulations Relating to Coal, GHGs and CCRs

Approximately 86% of FirstEnergy's generation fleet capacity is coal-fired, totaling 3,093 MWs at MP and 1,367 MWs at AE Supply. Historically, coal-fired generating plants have greater exposure to the costs of complying with federal, state and local environmental statutes, rules and regulations relating to air emissions, including GHGs and CCR disposal, than other types of electric generation facilities. These legal requirements and any future initiatives could impose substantial additional costs and, in the case of GHG requirements, could raise uncertainty about the future viability of fossil fuels, particularly coal, as an energy source for new and existing electric generation facilities and could require our coal-fired generation plants to curtail generation or cease to generate. Failure to comply with any such existing or future legal requirements may also result in the assessment of fines and penalties. Significant resources also may be expended to defend against allegations of violations of any such requirements.

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

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

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

Our business plan calls for execution of extensive capital investments in electric generation, transmission and distribution, including but not limited to our Energizing the Future transmission expansion program, which has been extended to include $4.0 to $4.8 billion in investments from 2018 through 2021. We may be exposed to the risk of substantial price increases in, or the adequacy or availability of, the costs of labor and materials used in construction, nonperformance of equipment and increased costs due to delays, including delays relating to the procurement of permits or approvals, adverse weather or environmental matters. We engage numerous contractors and enter into a large number of construction agreements to acquire the necessary materials and/or obtain the required construction-related services. As a result, we are also exposed to the risk that these contractors and other counterparties could breach their obligations to us. Such risk could include our contractors' inabilities to procure sufficient skilled labor as well as potential work stoppages by that labor force. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements at then-current market prices that may exceed our contractual prices, with resulting delays in those and other projects. Although our agreements are designed to mitigate the consequences of a potential default by the counterparty, our actual exposure may be greater than these mitigation provisions. Also, because we enter into construction agreements for the necessary materials and to obtain the required construction related services, any cancellation by FirstEnergy of a construction agreement could result in significant termination payments or penalties. Any delays, increased costs or losses or cancellation of a construction project could adversely affect our business and results of operations, particularly if we are not permitted to recover any such costs in rates.

Changes in Technology and Regulatory Policies May Make Our Facilities Significantly Less Competitive and Adversely Affect Our Results of Operations

Traditionally, electricity is generated at large central station generation facilities. This method results in economies of scale and lower unit costs than newer generation technologies such as fuel cells, microturbines, windmills and photovoltaic solar cells. It is possible that advances in newer generation technologies will make newer generation technologies more cost-effective, or that changes in regulatory policy will create benefits that otherwise make these newer generation technologies even more competitive with central station electricity production. To the extent that newer generation technologies are connected directly to load, bypassing the transmission and distribution systems, potential impacts could include decreased transmission and distribution revenues, stranded assets and increased uncertainty in load forecasting and integrated resource planning and could adversely affect our business and results of operations.

Certain FirstEnergy Companies Have Guaranteed the Performance of Third Parties, Which May Result in Substantial Costs or the Incurrence of Additional Debt

Certain FirstEnergy companies have issued guarantees of the performance of others, which obligates such FirstEnergy companies to perform in the event that the third parties do not perform. For instance, FE is a guarantor under a syndicated senior secured term loan facility, under which Global Holding's outstanding principal balance is $235 million at June 30, 2018. In the event of non-performance by the third parties, FirstEnergy could incur substantial cost to fulfill this obligation and other obligations under such guarantees. Such performance guarantees could have a material adverse impact on our financial position and operating results.

Additionally, with respect to FEV's investment in Global Holding, it could require additional capital from its owners, including FEV, to fund operations and meet its obligations under its term loan facility. These capital requirements could be significant and if other partners do not fund the additional capital, resulting in FEV increasing its equity ownership and obtaining the ability to direct the significant activities of Global Holding, FEV may be required to consolidate Global Holding, increasing FirstEnergy's long-term debt by $255 million.

Energy Companies are Subject to Adverse Publicity Causing Less Favorable Regulatory and Legislative Outcomes Which Could have an Adverse Impact on Our Business

Energy companies, including FirstEnergy's utility subsidiaries, have been the subject of criticism on matters including the reliability of their distribution services and the speed with which they are able to respond to power outages, such as those caused by storm damage. Adverse publicity of this nature, as well as negative publicity associated with the operation or bankruptcy of nuclear and/or coal-fired facilities or proceedings seeking regulatory recoveries may cause less favorable legislative and regulatory outcomes and damage our reputation, which could have an adverse impact on our business.

Risks Associated with Regulation

We Have Taken a Series of Actions to Focus on Growing Our Regulated Operations, Particularly Within the Regulated Transmission Segment. Whether This Investment Strategy Will Deliver the Desired Result Is Subject to Certain Risks Which Could Adversely Affect Our Results of Operations and Financial Condition in the Future

We focus on capitalizing on investment opportunities available to our regulated operations - particularly within our Regulated Transmission segment - as we focus on delivering enhanced customer service and reliability. The success of these efforts will depend, in part, on successful recovery of our transmission investments. Factors that may affect rate recovery of our transmission investments include: (1) FERC’s timely approval of rates to recover such investments; (2) whether the investments are included in PJM's RTEP; (3) FERC's evolving policies with respect to incentive rates for transmission assets; (4) FERC's evolving policies with respect to the calculation of the base ROE component of transmission rates, as articulated in FERC's Opinion No. 531 and related orders; (5) consideration of the objections of those who oppose such investments and their recovery; and (6) timely development, construction, and operation of the new facilities.

The success of these efforts will also depend, in part, on any future distribution rate cases or other filings seeking cost recovery for distribution system enhancements in the states where our Utilities operate and transmission rate filings at FERC. Any denial of, or delay in, the approval of any future distribution or transmission rate requests could restrict us

from fully recovering our cost of service, may impose risks on the Regulated Transmission and Regulated Distribution operations, and could have a material adverse effect on our regulatory strategy and results of operations.
Our efforts also could be impacted by our ability to finance the proposed expansion projects while maintaining adequate liquidity. There can be no assurance that our efforts to reflect a more regulated business profile will deliver the desired result which could adversely affect our future results of operations and financial condition.

Any Subsequent Modifications to, Denial of, or Delay in the Effectiveness of the PUCO's Approval of the DMR Could Impose Significant Risks on FirstEnergy's Operations and Materially and Adversely Impact the Credit Ratings, Results of Operations and Financial Condition of FirstEnergy

On October 12, 2016, the PUCO denied the Ohio Companies' modified Rider RRS and, in accordance with the PUCO Staff's recommendation, approved a new DMR providing for the collection of $132.5 million annually for three years with a possible extension for an additional two years. Rider DMR will be grossed up for federal income taxes, resulting in an approved amount of approximately $168 million annually in 2018 and 2019. Various parties have appealed the PUCO's denial of subsequent applications for rehearing to the Ohio Supreme Court. Any subsequent modification to, denial of, or delay in the effectiveness of, the PUCO's order approving the DMR could impose risks on our operations and materially and adversely impact the credit ratings, results of operations and financial condition of FirstEnergy.

Complex and Changing Government Regulations, Including Those Associated with Rates and Rate Cases and Restrictions and Prohibitions on Certain Business Dealings Could Have a Negative Impact on Our Business, Financial Condition, Results of Operations and Cash Flows

We are subject to comprehensive regulation by various federal, state and local regulatory agencies that significantly influence our operating environment. Changes in, or reinterpretations of, existing laws or regulations, or the imposition of new laws or regulations, could require us to incur additional costs or change the way we conduct our business, and therefore could have a material adverse impact on our results of operations.

Our transmission and operating utility subsidiaries currently provide service at rates approved by one or more regulatory commissions. Thus, the rates a utility is allowed to charge may be decreased as a result of actions taken by FERC or by a state regulatory commission in which the Utilities operate. Also, these rates may not be set to recover such utility's expenses at any given time. Additionally, there may also be a delay between the timing of when costs are incurred and when costs are recovered. For example, we may be unable to timely recover the costs for our energy efficiency investments or expenses and additional capital or lost revenues resulting from the implementation of aggressive energy efficiency programs. While rate regulation is premised on providing an opportunity to earn a reasonable return on invested capital and recovery of operating expenses, there can be no assurance that the applicable regulatory commission will determine that all of our costs have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of our costs in a timely manner. Further, there can be no assurance that we will retain the expected recovery in future rate cases.

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

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

Each of the Utilities' retail rates are set by its respective regulatory agency for utilities in the state in which it operates - in Maryland by the MDPSC, in Ohio by the PUCO, in New Jersey by the NJBPU, in Pennsylvania by the PPUC, in West Virginia by the WVPSC and in New York by the NYPSC - through traditional, cost-based regulated utility ratemaking. As a result, any of the Utilities may not be permitted to recover its costs and, even if it is able to do so, there may be a significant delay between the time it incurs such costs and the time it is allowed to recover them. Factors that may affect outcomes in the distribution rate cases include: (i) the value of plant in service; (ii) authorized rate of return; (iii) capital structure (including hypothetical capital structures); (iv) depreciation rates; (v) the allocation of shared costs, including consolidated deferred income taxes and income taxes payable across the Utilities; (vi) regulatory approval of rate recovery mechanisms for capital spending programs (including for example accelerated deployment of smart meters); and (vii) the accuracy of forecasts used for ratemaking purposes in "future test year" cases.

FirstEnergy can provide no assurance that any base rate request filed by any of the Utilities will be granted in whole or in part. Any denial of, or delay in, any base rate request could restrict the applicable Utility from fully recovering its costs of service, may impose risks on its operations, and may negatively impact its results of operations, cash flows and financial condition. In addition, to the extent that any of the Utilities seeks rate increases after an extended period of frozen or capped rates, pressure may be exerted on the applicable legislators and regulators to take steps to control rate increases, including through some form of rate increase moderation, reduction or freeze. Any related public discourse and debate can increase uncertainty associated with the regulatory process, the level of rates and revenues that are ultimately obtained, and the ability of the Utility to recover costs. Such uncertainty may restrict operational flexibility and resources, and reduce liquidity and increase financing costs.

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

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

There are multiple matters pending before FERC. There can be no assurance as to the outcome of these proceedings and an adverse result could have an adverse impact on FirstEnergy’s results of operations and business conditions.

The Business Operations of Our Subsidiaries That Sell Wholesale Power Are Subject to Regulation by FERC and Could be Adversely Affected by Such Regulation

FERC granted the Utilities authority to sell electric energy, capacity and ancillary services at market-based rates. These orders also granted waivers of certain FERC accounting, record-keeping and reporting requirements, as well as, for certain of these subsidiaries, waivers of the requirements to obtain FERC approval for issuances of securities. FERC’s orders that grant this market-based rate authority reserve with FERC the right to revoke or revise that authority if FERC subsequently determines that these companies can exercise market power in transmission or generation, or create barriers to entry, or have engaged in prohibited affiliate transactions. In the event that one or more of FirstEnergy's market-based rate authorizations were to be revoked or adversely revised, the affected FirstEnergy subsidiaries may be subject to sanctions and penalties, and would be required to file with FERC for authorization of individual wholesale sales transactions, which could involve costly and possibly lengthy regulatory proceedings and the loss of flexibility afforded by the waivers associated with the current market-based rate authorizations.

Energy Efficiency and Peak Demand Reduction Mandates and Energy Price Increases Could Negatively Impact Our Financial Results

A number of regulatory and legislative bodies have introduced requirements and/or incentives to reduce peak demand and energy consumption. Such conservation programs could result in load reduction and adversely impact our financial results in different ways. We currently have energy efficiency riders in place to recover the cost of these programs either at or near a current recovery time frame in the states where we operate.

Currently, only our Ohio Companies recover lost distribution revenues that result between distribution rate cases. In our regulated operations, conservation could negatively impact us depending on the regulatory treatment of the associated impacts. Should we be required to invest in conservation measures that result in reduced sales from effective conservation, regulatory lag in adjusting rates for the impact of these measures could have a negative financial impact. We have already been adversely impacted by reduced electric usage due in part to energy conservation efforts such as the use of efficient lighting products such as CFLs, halogens and LEDs. We could also be adversely impacted if any future energy price increases result in a decrease in customer usage. We are unable to determine what impact, if any, conservation and increases in energy prices will have on our financial condition or results of operations.

Additionally, failure to meet regulatory or legislative requirements to reduce energy consumption or otherwise increase energy efficiency could result in penalties that could adversely affect our financial results.

Mandatory Renewable Portfolio Requirements Could Negatively Affect Our Costs and Have an Adverse Effect on Our Financial Condition and Results of Operations

Where federal or state legislation mandates the use of renewable and alternative fuel sources, such as wind, solar, biomass and geothermal and such legislation does not also provide for adequate cost recovery, it could result in significant changes in our business, including material increases in REC purchase costs, purchased power costs and capital expenditures. Such mandatory renewable portfolio requirements may have an adverse effect on our financial condition and results of operations.

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

FirstEnergy is subject to various local, state and federal taxes, including income, franchise, real estate, sales and use and employment-related taxes. We exercise significant judgment in calculating such tax obligations, booking reserves as necessary to reflect potential adverse outcomes regarding tax positions we have taken and utilizing tax benefits, such as carryforwards and credits. Additionally, various tax rate and fee increases may be proposed or considered in connection with such changes in local, state or federal tax law. We cannot predict whether legislation or regulation will be introduced, the form of any legislation or regulation, or whether any such legislation or regulation will be passed by legislatures or regulatory bodies. Any such changes, or any adverse tax audit results or adverse tax rulings on positions taken by FirstEnergy or its subsidiaries could have a negative impact on its results of operations, financial condition and cash flows.

In addition, in December 2017, Congress passed the Tax Act. Various state regulatory proceedings have been initiated to investigate the impact of the Tax Act on the Utilities’ rates and charges, and FERC recently took action to address the impact of the Tax Act on FERC-jurisdictional rates, including transmission and electric wholesale rates. FirstEnergy continues to work with state regulatory commissions to determine appropriate changes to customer rates and, beginning in the first quarter of 2018, began to track and apply regulatory accounting treatment for the expected rate impact of changes in current taxes resulting from the Tax Act. FirstEnergy has also reflected the impact of changes to current taxes in its normal update to FERC-jurisdictional formula transmission rates and will continue to work with the commission regarding whether and how FERC should address possible changes to transmission and wholesale rates resulting from the Tax Act.

We cannot predict whether, when or to what extent new tax regulations, interpretations or rulings will be issued, nor is the short-term or long-term impact of proposed tax reform clear. Any future reform of U.S. tax laws may be enacted in a manner that negatively impacts our results of operations, financial condition, business operations, earnings and is adverse to FE's shareholders. Furthermore, with respect to the Utilities and our transmission-owning affiliates, FirstEnergy cannot predict what, if any, response state regulatory commissions or FERC may have and the potential response of such authorities regarding the rates and charges of the Utilities and our transmission-owning affiliates.

The EPA is Conducting NSR Investigations at Generating Plants that We Currently or Formerly Owned, the Results of Which Could Negatively Impact Our Results of Operations and Financial Condition

We may be subject to risks from changing or conflicting interpretations of existing laws and regulations, including, for example, the applicability of the EPA's NSR programs. Under the CAA, modification of our generation facilities in a manner that results in increased emissions could subject our existing generation facilities to the far more stringent new source standards applicable to new generation facilities.

The EPA has taken the view that many companies, including many energy producers, have been modifying emissions sources in violation of NSR standards during work considered by the companies to be routine maintenance. The EPA has investigated alleged violations of the NSR standards at certain of our existing and former generating facilities. We intend to vigorously pursue and defend our position, but we are unable to predict their outcomes. If NSR and similar requirements are imposed on our generation facilities, in addition to the possible imposition of fines, compliance could entail significant capital investments in pollution control technology, which could have an adverse impact on our business, results of operations, cash flows and financial condition.

Costs of Compliance with Environmental Laws are Significant, and the Cost of Compliance with New Environmental Laws, Including Limitations on GHG Emissions, Could Adversely Affect Cash Flow and Profitability

Our operations are subject to extensive federal, state and local environmental statutes, rules and regulations. Compliance with these legal requirements requires us to incur costs for, among other things, installation and operation of pollution control equipment, emissions monitoring and fees, remediation and permitting at our facilities. These expenditures have been significant in the past and may increase in the future. We may be forced to shut down other facilities or change their operating status, either temporarily or permanently, if we are unable to comply with these or other existing or new environmental requirements, or if the expenditures required to comply with such requirements are unreasonable.

Moreover, new environmental laws or regulations including, but not limited to CWA effluent limitations imposing more stringent water discharge regulations, or changes to existing environmental laws or regulations may materially increase our costs of compliance or accelerate the timing of capital expenditures. Our compliance strategy, including but not limited to, our assumptions regarding estimated compliance costs, although reasonably based on available information, may not successfully address future relevant standards and interpretations. If we fail to comply with environmental laws and regulations or new interpretations of longstanding requirements, even if caused by factors beyond our control, that failure could result in the assessment of civil or criminal liability and fines. In addition, any alleged violation of environmental laws and regulations may require us to expend significant resources to defend against any such alleged violations.

At the international level, 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 in September 2016, joined in adopting the agreement reached on December 12, 2015 at the United Nations Framework Convention on Climate Change meetings in Paris. However, on June 1, 2017, the Trump Administration announced that the U.S. would cease all participation in the 2015 Paris Agreement. Due to the uncertainty of control technologies available to reduce GHG emissions, any other legal obligation that requires substantial reductions of GHG emissions could result in substantial additional costs, adversely affecting cash flow and profitability, and raise uncertainty about the future viability of fossil fuels, particularly coal, as an energy source for new and existing electric generation facilities.

We Could be Exposed to Private Rights of Action Relating to Environmental Matters Seeking Damages Under Various State and Federal Law Theories Which Could Have an Adverse Impact on Our Results of Operations, Financial Condition and Business Operations

Private individuals may seek to enforce environmental laws and regulations against us and could allege personal injury, property damages or other relief. For example, claims have been made against certain energy companies alleging that CO_2 emissions from power generating facilities constitute a public nuisance under federal and/or state common law. While FirstEnergy is not a party to this litigation, it, and/or one of its subsidiaries, could be named in other actions making similar allegations. An unfavorable ruling in any such case could result in the need to make modifications to our coal-fired plants or reduce emissions, suspend operations or pay money damages or penalties. Adverse rulings in these or other types of actions could have an adverse impact on our results of operations and financial condition and could significantly impact our business operations.

We Are or May Be Subject to Environmental Liabilities, Including Costs of Remediation of Environmental Contamination at Current or Formerly Owned Facilities, Which Could Have a Material Adverse effect on Our Results of Operations and Financial Condition

We may be subject to liability under environmental laws for the costs of remediating environmental contamination of property now or formerly owned or operated by us and of property contaminated by hazardous substances that we may have generated regardless of whether the liabilities arose before, during or after the time we owned or operated the facilities. We are currently involved in a number of proceedings relating to sites where hazardous substances have been released and we may be subject to additional proceedings in the future. We also have current or previous ownership interests in sites associated with the production of gas and the production and delivery of electricity for which we may be liable for additional costs related to investigation, remediation and monitoring of these sites. Remediation activities associated with our former MGP operations are one source of such costs. Citizen groups or others may bring litigation over environmental issues including claims of various types, such as property damage, personal injury, and citizen challenges to compliance decisions on the enforcement of environmental requirements, such as opacity and other air quality standards, which could subject us to penalties, injunctive relief and the cost of litigation. We cannot predict the amount and timing of all future expenditures (including the potential or magnitude of fines or penalties) related to such environmental matters, although we expect that they could be material.

In some cases, a third party who has acquired assets from us has assumed the liability we may otherwise have for environmental matters related to the transferred property. If the transferee fails to discharge the assumed liability or disputes its responsibility, a regulatory authority or injured person could attempt to hold us responsible, and our remedies against the transferee may be limited by the financial resources of the transferee.

We Are and May Become Subject to Legal Claims Arising from the Presence of Asbestos or Other Regulated Substances at Some of Our Facilities

We have been named as a defendant in pending asbestos litigations involving multiple plaintiffs and multiple defendants, in several states. The majority of these claims arise out of alleged past exposures by contractors (and in Pennsylvania, former employees) at both currently and formerly owned electric generation plants. In addition, asbestos and other regulated substances are, and may continue to be, present at currently owned facilities where suitable alternative materials are not available. We believe that any remaining asbestos at our facilities is contained and properly identified in accordance with applicable governmental regulations, including OSHA. The continued presence of asbestos and other regulated substances at these facilities, however, could result in additional actions being brought against us. This is further complicated by the fact that many diseases, such as mesothelioma and cancer, have long latency periods in which the disease process develops, thus making it impossible to accurately predict the types and numbers of such claims in the near future. While insurance coverages exist for many of these pending asbestos litigations, others have no such coverages, resulting in FirstEnergy being responsible for all defense expenditures, as well as any settlements or verdict payouts.

The Risks Associated with Climate Change May Have an Adverse Impact on Our Business Operations, Operating Results and Cash Flows

Physical risks of climate change, such as more frequent or more extreme weather events, changes in temperature and precipitation patterns, and other related phenomena, could affect some, or all, of our operations. Severe weather or other natural disasters could be destructive, which could result in increased costs, including supply chain costs. An extreme weather event within the Utilities' service areas can also directly affect their capital assets, causing disruption in service to customers due to downed wires and poles or damage to other operating equipment. Further, as extreme weather conditions increase system stress, we may incur costs relating to additional system backup or service interruptions, and in some instances, we may be unable to recover such costs. For all of these reasons, these physical risks could have an adverse financial impact on our business operations, operating results and cash flows. Climate change poses other financial risks as well. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease depending on the duration and magnitude of the changes. Increased energy use due to weather changes may require us to invest in additional system assets and purchase additional power. Additionally, decreased energy use due to weather changes may affect our financial condition through decreased rates, revenues, margins or earnings.

Future Changes in Accounting Standards May Affect Our Reported Financial Results
The SEC, FASB or other authoritative bodies or governmental entities may issue new pronouncements or new interpretations of existing accounting standards that may require us to change our accounting policies. These changes are beyond our control, can be difficult to predict and could materially impact how we report our financial condition and results of operations. We could be required to apply a new or revised standard retroactively, which could adversely affect our financial position.

Risks Associated with Financing and Capital Structure

In the Event of Volatility or Unfavorable Conditions in the Capital and Credit Markets, Our Business, Including the Immediate Availability and Cost of Short-Term Funds for Liquidity Requirements, Our Ability to Meet Long-Term Commitments and the Competitiveness and Liquidity of Energy Markets May be Adversely Affected, Which Could Negatively Impact Our Results of Operations, Cash Flows and Financial Condition
We rely on the capital markets to meet our financial commitments and short-term liquidity needs if internal funds are not available from our operations. We also use letters of credit provided by various financial institutions to support our hedging operations. We also deposit cash in short-term investments. In the event of volatility in the capital and credit markets, our ability to draw on our credit facilities and cash may be adversely affected. Our access to funds under those credit facilities is dependent on the ability of the financial institutions that are parties to the facilities to meet their funding commitments. Those institutions may not be able to meet their funding commitments if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests within a short period of time. Any delay in our ability to access those funds, even for a short period of time, could have a material adverse effect on our results of operations and financial condition.
Should there be fluctuations in the capital and credit markets as a result of uncertainty, changing or increased regulation, reduced alternatives or failures of significant foreign or domestic financial institutions or foreign governments, our access to liquidity needed for our business could be adversely affected. Unfavorable conditions could require us to take measures to conserve cash until the markets stabilize or until alternative credit arrangements or other funding for our business needs can be arranged. Such measures could include deferring capital expenditures, changing hedging strategies to reduce collateral-posting requirements, and reducing or eliminating future dividend payments or other discretionary uses of cash.
Energy markets depend heavily on active participation by multiple counterparties, which could be adversely affected should there be disruptions in the capital and credit markets. Reduced capital and liquidity and failures of significant institutions that participate in the energy markets could diminish the liquidity and competitiveness of energy markets that are important to our business. Perceived weaknesses in the competitive strength of the energy markets could lead to pressures for greater regulation of those markets or attempts to replace those market structures with other mechanisms for the sale of power, including the requirement of long-term contracts, which could have a material adverse effect on our results of operations and cash flows.
Interest Rates and/or a Credit Rating Downgrade Could Negatively Affect Our or Our Subsidiaries' Financing Costs, Ability to Access Capital and Requirement to Post Collateral
We have near-term exposure to interest rates from outstanding indebtedness indexed to variable interest rates, and we have exposure to future interest rates to the extent we seek to raise debt in the capital markets to meet maturing debt obligations and fund construction or other investment opportunities. Past disruptions in capital and credit markets have resulted in higher interest rates on new publicly issued debt securities, increased costs for certain of our variable interest rate debt securities and failed remarketing of variable interest rate tax-exempt debt issued to finance certain of our facilities. Similar future disruptions could increase our financing costs and adversely affect our results of operations. Also, interest rates could change as a result of economic or other events that are beyond our risk management processes. As a result, we cannot always predict the impact that our risk management decisions may have on us if actual events lead to greater losses or costs that our risk management positions were intended to hedge. Although we employ risk management techniques to hedge against interest rate volatility, significant and sustained increases in market interest rates could materially increase our financing costs and negatively impact our reported results of operations.

We rely on access to bank and capital markets as sources of liquidity for cash requirements not satisfied by cash from operations. A downgrade in our or our subsidiaries' credit ratings from the nationally recognized credit rating agencies, particularly to a level below investment grade, could negatively affect our ability to access the bank and capital markets, especially in a time of uncertainty in either of those markets, and may require us to post cash collateral to support outstanding commodity positions in the wholesale market, as well as available letters of credit and other guarantees. Furthermore, a downgrade could increase the cost of such capital by causing us to incur higher interest rates and fees associated with such capital. A rating downgrade would increase our interest expense on certain of FirstEnergy's long-term debt obligations and would also increase the fees we pay on our various existing credit facilities, thus increasing the cost of our working capital. A rating downgrade could also impact our ability to grow our regulated businesses by substantially increasing the cost of, or limiting access to, capital.

Any Default by Customers or Other Counterparties Could Have a Material Adverse Effect on Our Results of Operations and Financial Condition

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

We Must Rely on Cash from Our Subsidiaries and Any Restrictions on Our Utility Subsidiaries' Ability to Pay Dividends or Make Cash Payments to Us May Adversely Affect Our Cash Flows and Financial Condition

We are a holding company and our investments in our subsidiaries are our primary assets. Substantially all of our business is conducted by our subsidiaries. Consequently, our cash flow, including our ability to pay dividends and service debt, is dependent on the operating cash flows of our subsidiaries and their ability to upstream cash to the holding company. Any inability of our subsidiaries to pay dividends or make cash payments to us may adversely affect our cash flows and financial condition.

Additionally, our utility and transmission subsidiaries are regulated by various state utility and federal commissions that generally possess broad powers to ensure that the needs of utility customers are being met. Those state and federal commissions could attempt to impose restrictions on the ability of our utility and transmission subsidiaries to pay dividends or otherwise restrict cash payments to us.

Our Mandatorily Convertible Preferred Stock Will be Converted into Common Stock, at the Latest, in Two Years from the Date of Issuance and the Holders Thereof Have Registration Rights. Upon Conversion of the Preferred Shares, the Number of Common Shares Eligible for Future Resale in the Public Market Will Increase and May Result in Dilution to Common Shareholders. This May Have an Adverse Effect on the Market Price of Common Stock.

On January 22, 2018, FE issued $2.5 billion of equity, which included $1.62 billion of mandatorily convertible preferred equity with an initial conversion price of $27.42 per share and $850 million of common equity issued at $28.22 per share. The issuance of common equity created some dilution to existing common holders. The preferred shares contain an optional conversion for holders beginning in July 2018, and any remaining preferred shares will mandatorily convert in 18 months from issuance, subject to limited exceptions.

Upon the conversion of the mandatorily convertible preferred stock, additional shares, up to a maximum of 58,964,222 shares, of our common stock will be issued, which results in dilution to our common stockholders, and will increase the number of shares eligible for resale in the public market. Sales of substantial numbers of such shares in the public market could adversely affect the market price of our common stock. As of July 27, 2018, 224,714 shares of preferred stock have been converted into 8,195,257 shares of common stock at the option of the holders.

We Cannot Assure Common and Preferred Shareholders that Future Dividend Payments Will be Made, or if Made, in What Amounts They May be Paid

Our Board of Directors will continue to regularly evaluate our common stock dividend and determine an appropriate dividend each quarter taking into account such factors as, among other things, our earnings, financial condition and cash flows from subsidiaries, as well as general economic and competitive conditions. We cannot assure common or preferred shareholders that dividends will be paid in the future, or that, if paid, dividends will be at the same amount or with the same frequency as in the past. Further, the terms of the outstanding preferred stock require that preferred shareholders receive dividends alongside the common shareholders on an as-converted, pro rata basis.

The Recognition of Impairments of Goodwill and Long-Lived Assets Has Adversely Affected Our Results of Operations and Additional Impairments Could Have a Material Adverse Effect on FirstEnergy’s Business, Financial Condition, Results of Operations, Liquidity and the Trading Price of FirstEnergy's Securities

We have approximately $5.6 billion of goodwill on our Consolidated Balance Sheet as of June 30, 2018. Goodwill is tested for impairment annually as of July 31 or whenever events or changes in circumstances indicate impairment may have occurred. Key assumptions incorporated in the estimated cash flows used for the impairment analysis requiring significant management judgment include: discount rates, growth rates, future energy and capacity pricing, projected operating income, changes in working capital, projected capital expenditures, projected funding of pension plans, expected results of future rate proceedings, the impact of pending carbon and other environmental legislation and terminal multiples.

We are unable to predict whether further impairments of one or more of our long-lived assets or investments may occur in the future. The actual timing and amounts of any impairments to goodwill, or long-lived assets in the future depends on many factors, including the outcome of the strategic review, interest rates, sector market performance, our capital structure, natural gas or other commodity prices, market prices for power, results of future rate proceedings, operating and capital expenditure requirements, the value of comparable acquisitions, environmental regulations and other factors. A determination that goodwill, a long-lived asset, or other investments are impaired would result in a non-cash charge that could materially adversely affect our results of operations and capitalization.

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

Not applicable.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5. OTHER INFORMATION

FE is attaching Exhibit 99 for the purpose of updating the description of its capital stock to primarily reflect the previously disclosed designation of Series A Convertible Preferred Stock. The Description of Capital Stock is attached as Exhibit 99 and is incorporated herein by reference. The Company is filing the attached Description of Capital Stock for the purpose of incorporating it by reference into registration statements filed by the Company.

The attached description highlights important terms of the capital stock as of the date hereof. This description is not a complete description of the terms of the capital stock and is qualified by reference to FirstEnergy's Amended Articles of Incorporation and Amended Code of Regulations, each as amended and as previously filed with the SEC, as well as the applicable provisions of Ohio law.

ITEM 6. EXHIBITS

	Exhibit Number	Description
(A)	3	FirstEnergy Corp. Amended Code of Regulations, as amended May 17, 2011.
(B)	10.1	Form of Director and Officer Indemnification Agreement (incorporated by reference to FE's Form 8-K filed May 16, 2018, Exhibit 10.1, File No. 333-21011).
(B)	10.2	Executive Voluntary Enhanced Retirement Program (incorporated by reference to FE's Form 8-K filed July 23, 2018, Exhibit 10.1, File No. 333-21011).
(A)	12	Consolidated ratios of earnings to fixed charges.
(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.
(A)	99	Description of Capital Stock of FirstEnergy Corp.
	101	The following materials from the Quarterly Report on Form 10-Q of FirstEnergy Corp. for the period ended June 30, 2018, formatted in XBRL (Extensible Business Reporting Language): (i) Consolidated Statements of Income and Consolidated Statements of Comprehensive Income, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Cash Flows, (iv) related notes to these financial statements and (v) document and entity information.

(A) Provided herein in electronic format as an exhibit.
(B) Management contract or compensatory plan contract or arrangement filed pursuant to Item 601 of Regulation S-K.

Pursuant to paragraph (b)(4)(iii)(A) of Item 601 of Regulation S-K, except as set forth above FirstEnergy has not 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 hereby agrees to furnish to the SEC on request any such documents.

SIGNATURES

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

July 31, 2018

FIRSTENERGY CORP.
Registrant

/s/ Jason J. Lisowski
Jason J. Lisowski
Vice President, Controller
and Chief Accounting Officer