FIRSTENERGY CORP
Form 10-Q
April 23, 2019

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 March 31, 2019

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 every Interactive Data File required to be submitted 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 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 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 MARCH 31, 2019
Common Stock, $0.10 par value	531,442,309

FirstEnergy Website 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 website at www.firstenergycorp.com. 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 website 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 website and recognizes FirstEnergy’s website 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 website by signing up for email alerts and RSS feeds on the "Investors" page of FirstEnergy's website. 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 website, 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 from commodity-based generation, including, without limitation, mitigating exposure for remedial activities associated with formerly owned generation assets.
- The risks associated with the FES Bankruptcy that could adversely affect us, our liquidity or results of operations, including, without limitation, that conditions to the FES Bankruptcy settlement agreement may not be met or that the FES Bankruptcy settlement agreement may not be otherwise consummated, and if so, the potential for litigation and payment demands against us by FES or FENOC or their creditors.
- The ability to accomplish or realize anticipated benefits from strategic and financial goals, including, but not limited to, our strategy to operate and grow as a fully regulated business, to execute our transmission and distribution investment plans, to continue to reduce costs through FE Tomorrow and other initiatives, and to improve our credit metrics, strengthen our balance sheet and grow earnings.
- Legislative and regulatory developments at the federal and state levels, including, but not limited to, matters related to rates, compliance and enforcement activity.
- Economic and weather conditions affecting future operating results, such as significant weather events and other natural disasters, and associated regulatory events or actions.
- Changes in assumptions regarding economic conditions within our territories, the reliability of our transmission and distribution system, or the availability of capital or other resources supporting identified transmission and distribution investment opportunities.
- Changes in customers' demand for power, including, but not limited to, the impact of state and federal energy efficiency and peak demand reduction mandates.
- Changes in national and regional economic conditions affecting us and/or our major industrial and commercial customers or others with which we do business.
- The risks associated with cyber-attacks and other disruptions to our information technology system that may compromise our operations, and data security breaches of sensitive data, intellectual property and proprietary or personally identifiable information.
- The ability to comply with applicable state and federal reliability standards and energy efficiency and peak demand reduction mandates.
- Changes to federal and state environmental laws and regulations, including, but not limited to, those related to climate change.
- Changing market conditions affecting the measurement of certain liabilities and the value of assets held in our pension trusts and other trust funds, or causing us to make additional contributions sooner, or in amounts that are larger, than currently anticipated.
- The risks associated with the decommissioning of our retired and former nuclear facilities.
- The risks and uncertainties associated with litigation, arbitration, mediation and like proceedings.
- Labor disruptions by our unionized workforce.
- Changes to significant accounting policies.
- 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.

- Actions that may be taken by credit rating agencies that could negatively affect either our access to or terms of financing or our financial condition and liquidity.
- The risks and other factors discussed from time to time in our SEC filings.

Dividends declared from time to time on our common stock, and thereby on our preferred stock, during any period may in the aggregate vary from prior periods due to circumstances considered by our 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 the most recent Annual Report on Form 10-K and any subsequent Quarterly Reports on Form 10-Q and 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
AGC	Allegheny Generating Company, formerly a generation subsidiary of AE Supply that became a wholly owned 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
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
FELHC	FirstEnergy License 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 LLC, and FGMUC, which provides energy-related products and services
FES Debtors	FES and FENOC
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, MAIT and TrAIL, and has a joint venture in PATH
FEV	FirstEnergy Ventures Corp., which invests in certain unregulated enterprises and business ventures
FG	FirstEnergy Generation, LLC, a wholly owned subsidiary of FES, which owns and operates non-nuclear generating facilities
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
Transmission Companies	ATSI, MAIT and TrAIL
Utilities	OE, CEI, TE, Penn, JCP&L, ME, PN, MP, PE and WP
WP	West Penn Power Company, a Pennsylvania electric utility operating subsidiary

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

ACE	Affordable Clean Energy	EPA	United States Environmental Protection Agency
ADIT	Accumulated Deferred Income Taxes	EPS	Earnings per Share
AEP	American Electric Power Company, Inc.	ERO	Electric Reliability Organization
AFS	Available-for-sale	ESP IV	Electric Security Plan IV
AFUDC	Allowance for Funds Used During Construction	Facebook®	Facebook is a registered trademark of Facebook, Inc.
ALJ	Administrative Law Judge	FASB	Financial Accounting Standards Board
AOCI	Accumulated Other Comprehensive Income	FERC	Federal Energy Regulatory Commission
Apple®	Apple®, iPad® and iPhone® are registered trademarks of Apple Inc.	FE Tomorrow	FirstEnergy's initiative launched in late 2016 to identify its optimal organizational structure and properly align corporate costs and systems to efficiently support a fully regulated company going forward
ARO	Asset Retirement Obligation	FES Bankruptcy	FES Debtors' voluntary petitions for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code with the Bankruptcy Court
ARP	Alternative Revenue Program	Fitch	Fitch Ratings
ARR	Auction Revenue Right	FPA	Federal Power Act
ASC	Accounting Standard Codification	FTR	Financial Transmission Right
ASU	Accounting Standards Update	GAAP	Accounting Principles Generally Accepted in the United States of America
Bankruptcy Court	U.S. Bankruptcy Court in the Northern District of Ohio in Akron	GHG	Greenhouse Gases
Bath County	Bath County Pumped Storage Hydro-Power Station	IIP	Infrastructure Investment Program
BGS	Basic Generation Service	IRS	Internal Revenue Service
BNSF	BNSF Railway Company	ISO	Independent System Operator
BRA	PJM RPM Base Residual Auction	JCP&L Reliability Plus	JCP&L Reliability Plus IIP
CAA	Clean Air Act	kW	Kilowatt
CCR	Coal Combustion Residuals	LBR	Little Blue Run
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act of 1980	LIBOR	London Interbank Offered Rate
CFR	Code of Federal Regulations	LOC	Letter of Credit
CO_2	Carbon Dioxide	LS Power	LS Power Equity Partners III, LP
CPP	EPA's Clean Power Plan	LTIIPs	Long-Term Infrastructure Improvement Plans
CSAPR	Cross-State Air Pollution Rule	MDPSC	Maryland Public Service Commission
CSX	CSX Transportation, Inc.	MGP	Manufactured Gas Plants
CTA	Consolidated Tax Adjustment	MISO	Midcontinent Independent System Operator, Inc.
CWA	Clean Water Act	mmBTU	One Million British Thermal Units
D.C. Circuit		Moody’s	Moody’s Investors Service, Inc.

	United States Court of Appeals for the District of Columbia Circuit		
DCR	Delivery Capital Recovery	MW	Megawatt
DMR	Distribution Modernization Rider	MWH	Megawatt-hour
DPM	Distribution Platform Modernization	NAAQS	National Ambient Air Quality Standards
DSIC	Distribution System Improvement Charge	NDT	Nuclear Decommissioning Trust
DSP	Default Service Plan	NERC	North American Electric Reliability Corporation
EDC	Electric Distribution Company	NJBPU	New Jersey Board of Public Utilities
EDCP	Executive Deferred Compensation Plan	NMB	Non-Market Based
EDIS	Electric Distribution Investment Surcharge	NOAC	Northwest Ohio Aggregation Coalition
EE&C	Energy Efficiency and Conservation	NOI	Notice of Inquiry
EGS	Electric Generation Supplier	NOL	Net Operating Loss
EGU	Electric Generation Units	NOPR	Notice of Proposed Rulemaking
EmPOWER Maryland	EmPOWER Maryland Energy Efficiency Act	NOx	Nitrogen Oxide
ENEC	Expanded Net Energy Cost	NRC	Nuclear Regulatory Commission

NUG	Non-Utility Generation	RFP	Request for Proposal
NYPSC	New York State Public Service Commission	RGGI	Regional Greenhouse Gas Initiative
OCA	Office of Consumer Advocate	ROE	Return on Equity
OCC	Ohio Consumers' Counsel	RPM	Reliability Pricing Model
OEPA	Ohio Environmental Protection Agency	RSS	Rich Site Summary
OMAEG	Ohio Manufacturers' Association Energy Group	RTEP	Regional Transmission Expansion Plan
OPEB	Other Post-Employment Benefits	RTO	Regional Transmission Organization
OPIC	Other Paid-in Capital	S&P	Standard & Poor’s Ratings Service
OVEC	Ohio Valley Electric Corporation	SBC	Societal Benefits Charge
PA DEP	Pennsylvania Department of Environmental Protection	SEC	United States Securities and Exchange Commission
PJM	PJM Interconnection, LLC	SIP	State Implementation Plan(s) Under the Clean Air Act
PJM Tariff	PJM Open Access Transmission Tariff	SO_2	Sulfur Dioxide
POLR	Provider of Last Resort	SOS	Standard Offer Service
POR	Purchase of Receivables	SPE	Special Purpose Entity
PPA	Purchase Power Agreement	SREC	Solar Renewable Energy Credit
PPB	Parts per Billion	SSO	Standard Service Offer
PPUC	Pennsylvania Public Utility Commission	Tax Act	Tax Cuts and Jobs Act adopted December 22, 2017
PUCO	Public Utilities Commission of Ohio	TMI-2	Three Mile Island Unit 2
PURPA	Public Utility Regulatory Policies Act of 1978	Twitter®	Twitter is a registered trademark of Twitter, Inc.
RCRA	Resource Conservation and Recovery Act	UCC	Official committee of unsecured creditors appointed in connection with the FES Bankruptcy
REC	Renewable Energy Credit	VIE	Variable Interest Entity
Regulation FD	Regulation Fair Disclosure promulgated by the SEC	VSCC	Virginia State Corporation Commission
RFC	ReliabilityFirst Corporation	WVPSC	Public Service Commission of West Virginia

PART I. FINANCIAL INFORMATION

ITEM I. Financial Statements

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

(In millions, except per share amounts)	For the Three Months Ended March 31, 2019	2018
REVENUES:		
Distribution services and retail generation	$2,309	$2,295
Transmission	352	319
Other	222	248
Total revenues[1]	2,883	2,862
OPERATING EXPENSES:		
Fuel	131	139
Purchased power	781	820
Other operating expenses	779	940
Provision for depreciation	297	277
Amortization (deferral) of regulatory assets, net	5	(148)
General taxes	261	254
Total operating expenses	2,254	2,282
OPERATING INCOME	629	580
OTHER INCOME (EXPENSE):		
Miscellaneous income, net	54	67
Interest expense	(253)	(248)
Capitalized financing costs	18	15
Total other expense	(181)	(166)
INCOME BEFORE INCOME TAXES	448	414
INCOME TAXES	93	233
INCOME FROM CONTINUING OPERATIONS	355	181
Discontinued operations (Note 3)[2]	(35)	1,188
NET INCOME	320	1,369
INCOME ALLOCATED TO PREFERRED STOCKHOLDERS (Note 4)	5	156
NET INCOME ATTRIBUTABLE TO COMMON STOCKHOLDERS	$315	$1,213

EARNINGS PER SHARE OF COMMON STOCK (Note 4):		
Basic - Continuing Operations	$0.66	$0.05
Basic - Discontinued Operations	(0.07)	2.50
Basic - Net Income Attributable to Common Stockholders	$0.59	$2.55
Diluted - Continuing Operations	$0.66	$0.05
Diluted - Discontinued Operations	(0.07)	2.49
Diluted - Net Income Attributable to Common Stockholders	$0.59	$2.54
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING:		
Basic	530	476
Diluted	533	478

(1) Includes excise and gross receipts tax collections of $102 million in the three months ended March 31, 2019 and 2018.

(2) Net of income tax expense (benefits) of $5 million and $(871) million for the three months ended March 31, 2019 and 2018, respectively.

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

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

(In millions)	For the Three Months Ended March 31, 2019	2018
NET INCOME	$320	$1,369
OTHER COMPREHENSIVE INCOME (LOSS):		
Pension and OPEB prior service costs	(7)	(18)
Amortized losses on derivative hedges	1	15
Change in unrealized gains on AFS securities	—	(106)
Other comprehensive loss	(6)	(109)
Income tax benefits on other comprehensive loss	(1)	(53)
Other comprehensive loss, net of tax	(5)	(56)
COMPREHENSIVE INCOME	$315	$1,313

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)	March 31, 2019	December 31, 2018
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 174	$ 367
Restricted cash	36	62
Receivables-		
Customers, net of allowance for uncollectible accounts of $48 in 2019 and $50 in 2018	1,263	1,221
Affiliated companies, net of allowance for uncollectible accounts of $928 in 2019 and $920 in 2018	—	20
Other, net of allowance for uncollectible accounts of $1 in 2019 and $2 in 2018	238	270
Materials and supplies, at average cost	268	252
Prepaid taxes and other	314	175
Current assets - discontinued operations	21	25
	2,314	2,392
PROPERTY, PLANT AND EQUIPMENT:		
In service	40,028	39,469
Less — Accumulated provision for depreciation	10,961	10,793
	29,067	28,676
Construction work in progress	1,199	1,235
	30,266	29,911
INVESTMENTS:		
Nuclear plant decommissioning trusts	843	790
Nuclear fuel disposal trust	259	256
Other	257	253
	1,359	1,299
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	5,618	5,618
Regulatory assets	102	91
Other	831	752
	6,551	6,461
	$ 40,490	$ 40,063
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 206	$ 503
Short-term borrowings	1,300	1,250
Accounts payable	892	965
Accounts payable - affiliated companies	30	—
Accrued taxes	562	533
Accrued compensation and benefits	253	318
Collateral	30	39
Other	1,051	1,026
	4,324	4,634
CAPITALIZATION:		
Stockholders’ equity-		

Common stock, $0.10 par value, authorized 700,000,000 shares - 531,442,309 and 511,915,450 shares outstanding as of March 31, 2019 and December 31, 2018, respectively	53	51
Preferred stock, $100 par value, authorized 5,000,000 shares, of which 1,616,000 are designated Series A Convertible Preferred - 209,822 and 704,589 shares outstanding as of March 31, 2019 and December 31, 2018, respectively	21	71
Other paid-in capital	11,381	11,530
Accumulated other comprehensive income	36	41
Accumulated deficit	(4,559)	(4,879)
Total stockholders' equity	6,932	6,814
Long-term debt and other long-term obligations	18,814	17,751
	25,746	24,565
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	2,620	2,502
Retirement benefits	2,417	2,906
Regulatory liabilities	2,574	2,498
Asset retirement obligations	822	812
Adverse power contract liability	85	89
Other	1,902	2,057
	10,420	10,864
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 14)		
	$ 40,490	$ 40,063

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 Three Months Ended March 31, 2019	2018
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$320	$1,369
Adjustments to reconcile net income to net cash from operating activities-		
(Gain) loss on disposal, net of tax (Note 3)	24	(1,239)
Depreciation and amortization, including regulatory assets, net, intangible assets and deferred debt-related costs	345	280
Deferred income taxes and investment tax credits, net	91	278
Retirement benefits, net of payments	(39)	(46)
Pension trust contributions	(500)	(1,250)
Changes in current assets and liabilities-		
Receivables	92	32
Materials and supplies	(12)	36
Prepaid taxes and other	(148)	(144)
Accounts payable	(143)	96
Accrued taxes	(81)	(145)
Accrued compensation and benefits	(123)	(108)
Other current liabilities	—	(15)
Collateral, net	(9)	(7)
Other	1	(17)
Net cash used for operating activities	(182)	(880)
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Long-term debt	1,400	—
Short-term borrowings, net	50	900
Preferred stock issuance	—	1,616
Common stock issuance	—	850
Redemptions and Repayments-		
Long-term debt	(628)	(1,476)
Preferred stock dividend payments	(3)	(21)
Common stock dividend payments	(201)	(171)
Other	(25)	(19)
Net cash provided from financing activities	593	1,679
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(554)	(583)
Proceeds from asset sales	—	20
Sales of investment securities held in trusts	153	300
Purchases of investment securities held in trusts	(162)	(322)
Notes receivable from affiliated companies	—	(500)
Asset removal costs	(65)	(57)
Other	(2)	(1)

Net cash used for investing activities	(630)	(1,143)
Net change in cash, cash equivalents, and restricted cash	(219)	(344)
Cash, cash equivalents, and restricted cash at beginning of period	429	643
Cash, cash equivalents, and restricted cash at end of period	$210	$299
SUPPLEMENTAL CASH FLOW INFORMATION:		
Non-cash transaction, beneficial conversion feature (Note 4)	$—	$296
Non-cash transaction, deemed dividend preferred stock (Note 4)	$—	$(113)

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

FIRSTENERGY CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

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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. AGC, JCP&L and MP control 3,790 MWs of total 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, 2018.

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 and permitted pursuant to GAAP. FE and its subsidiaries consolidate a VIE when it is determined that it is the primary beneficiary (see Note 10, "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 Note 3, "Discontinued Operations."

FES and FENOC Chapter 11 Filing

On March 31, 2018, the FES Debtors 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 concluded that it no longer had a controlling interest in the FES Debtors as the entities are subject to the jurisdiction of the Bankruptcy Court and, accordingly, as of March 31, 2018, the FES Debtors were deconsolidated from FirstEnergy's consolidated financial statements. Since such time, FE has accounted and will account for its investments in the FES Debtors at fair values of zero. FE concluded that in connection with the disposal, FES and FENOC became discontinued operations. See Note 3, "Discontinued Operations," for additional information.

On September 26, 2018, the Bankruptcy Court approved a FES Bankruptcy settlement agreement dated August 26, 2018, by and among FirstEnergy, two groups of key FES creditors (collectively, the FES Key Creditor Groups), the FES Debtors and the UCC. The FES Bankruptcy settlement agreement resolves certain claims by FirstEnergy against the FES Debtors and all claims by the FES Debtors and the FES Key Creditor Groups against FirstEnergy, and 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.
- FE will waive all pre-petition claims (other than those claims under the Tax Allocation Agreement for the 2018 tax year) and certain post-petition claims, against the FES Debtors related to the FES Debtors and their businesses, 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 the FES Debtors' unfunded pension obligations.

- A nonconsensual release of all claims against FirstEnergy by the FES Debtors' creditors, which was subsequently waived pursuant to the Waiver Agreement, discussed below.
- A $225 million cash payment from FirstEnergy.
- A $628 million aggregate principal amount note issuance by FirstEnergy to the FES Debtors, which may be decreased by the amount, if any, of cash paid by FirstEnergy to the FES Debtors under the Intercompany Income Tax Allocation Agreement for the tax benefits related to the sale or deactivation of certain plants.
- Transfer of the Pleasants Power Station and related assets, including the economic interests therein as of January 1, 2019, and a requirement that FE continue to provide access to the McElroy's Run CCR Impoundment Facility, which is not being transferred. FE will provide certain guarantees for retained environmental liabilities of AE Supply, including the McElroy’s Run CCR Impoundment Facility.
- FirstEnergy agrees to waive all pre-petition claims related to shared services and credit for nine months of the FES Debtors' shared service costs beginning as of April 1, 2018 through December 31, 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, subject to a cap, should FES offer a voluntary enhanced retirement package in 2019 and to offer certain other employee benefits (approximately $15 million recognized in the first quarter of 2019).
- FirstEnergy agrees to perform under the Intercompany Tax Allocation Agreement through the FES Debtors’ emergence from bankruptcy, at which time FirstEnergy will waive a 2017 overpayment for NOLs of approximately $71 million, reverse 2018 estimated payments for NOLs of approximately $88 million and pay the FES Debtors for the use of NOLs in an amount no less than $66 million for 2018 (approximately $52 million was paid in 2018, which amount will be finalized after filing the 2018 Federal tax return).

The FES Bankruptcy settlement agreement remains subject to satisfaction of certain conditions, most notably the issuance of a final order by the Bankruptcy Court approving the plan or plans of reorganization for the FES Debtors that are acceptable to FirstEnergy consistent with the requirements of the FES Bankruptcy settlement agreement. There can be no assurance that such conditions will be satisfied or the FES Bankruptcy settlement agreement will be otherwise consummated, and the actual outcome of this matter may differ materially from the terms of the agreement described herein. FirstEnergy will continue to evaluate the impact of any new factors on the settlement and their relative impact on the financial statements.

In connection with the FES Bankruptcy settlement agreement, FirstEnergy entered into a separation agreement with the FES Debtors to implement the separation of the FES Debtors and their businesses from FirstEnergy. A business separation committee was established between FirstEnergy and the FES Debtors to review and determine issues that arise in the context of the separation of the FES Debtors’ businesses from those of FirstEnergy.

As contemplated under the FES Bankruptcy settlement agreement, AE Supply entered into an agreement on December 31, 2018, to transfer the 1,300 MW Pleasants Power Station and related assets to FG, while retaining certain specified liabilities. Under the terms of the agreement, FG acquired the economic interests in Pleasants as of January 1, 2019, and AE Supply will operate Pleasants until the transfer is completed. After closing, AE Supply will continue to provide access to the McElroy's Run CCR Impoundment Facility, which is not being transferred, and FE will provide certain guarantees for retained environmental liabilities of AE Supply, including the McElroy’s Run CCR Impoundment Facility. The transfer of the Pleasants Power Station is subject to various customary and other closing conditions, including the effectiveness of a plan of reorganization for the FES Debtors in connection with the FES Bankruptcy. There can be no assurance that all closing conditions will be satisfied or that the transfer will be consummated.

On April 11, 2019, the Bankruptcy Court entered an order denying the FES Debtors’ disclosure statement approval motion. The Bankruptcy Court concluded that the nonconsensual third-party releases proposed under the plan of reorganization and which were a condition under the FES Bankruptcy settlement agreement for FirstEnergy's benefit, were legally impermissible and rendered the plan unconfirmable. On April 18, 2019, FirstEnergy consented to the waiver of the condition. In return, the FES Debtors agreed to provide FirstEnergy with the same third-party release provided in favor of certain other parties in any plan of reorganization and pay FirstEnergy approximately $60 million

in cash to resolve certain outstanding pension and service charges totaling $87 million, which resulted in FirstEnergy recognizing a $27 million pre-tax charge to income in the first quarter of 2019 ($17 million of which was recognized in continuing operations). Further, the FES Debtors agreed to initiate negotiations with the EPA, OEPA, PA DEP and the NRC to obtain those parties' cooperation with the FES Debtors' revised plan of reorganization. FirstEnergy may choose to participate in those negotiations at its option.

Capitalized Financing Costs

For each of the three months ended March 31, 2019 and 2018, capitalized financing costs on FirstEnergy's Consolidated Statements of Income include $13 million and $11 million, respectively, of allowance for equity funds used during construction and $5 million and $4 million, respectively, of capitalized interest.

Restricted Cash

Restricted cash primarily relates to the consolidated VIE's discussed in Note 10, "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 2016-02, "Leases (Topic 842)" (Issued February 2016 and subsequently updated to address implementation questions): The new guidance requires 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, as well as new qualitative and quantitative disclosures. FirstEnergy implemented a third-party software tool that assisted with the initial adoption and will assist with ongoing compliance. FirstEnergy chose to apply the requirements of the standard in the period of adoption (January 1, 2019) with no restatement of prior periods. Upon adoption, on January 1, 2019, FirstEnergy increased assets and liabilities by $186 million, with no impact to results of operations or cash flows. See Note 8, "Leases," for additional information on FirstEnergy's leases.

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 based upon the current expectation that such new standards will not significantly impact FirstEnergy's financial reporting.

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

ASU 2018-15, "Intangibles-Goodwill and Other-Internal-Use Software (Subtopic 350-40): Customer’s Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract" (Issued August 2018): ASU 2018-15 requires implementation costs incurred by customers in cloud computing arrangements to be deferred and recognized over the term of the arrangement, if those costs would be capitalized by the customers in a software licensing arrangement. The guidance will be effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019, with early adoption permitted.

2. REVENUE

FirstEnergy accounts for revenues from contracts with customers under ASC 606, Revenue from Contracts with Customers. 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 are excluded from recognition in the income statement and instead recorded through the balance sheet. 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.

FirstEnergy’s revenues are primarily derived from electric service provided by the Utilities and Transmission Companies.

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The following tables represent a disaggregation of revenue from contracts with customers for the three months ended March 31, 2019 and 2018 by type of service from each reportable segment:

	For the Three Months Ended March 31, 2019			
Revenues by Type of Service	Regulated Distribution	Regulated Transmission	Corporate/Other and Reconciling Adjustments [1]	Total
	(In millions)			
Distribution services[2]	$1,286	$ —	$ (21)	$1,265
Retail generation	1,058	—	(14)	1,044
Wholesale sales	106	—	4	110
Transmission[2]	—	352	—	352
Other	34	—	1	35
Total revenues from contracts with customers	$2,484	$ 352	$ (30)	$2,806
ARP	62	—	—	62
Other non-customer revenue	27	4	(16)	15
Total revenues	$2,573	$ 356	$ (46)	$2,883

[1] Includes eliminations and reconciling adjustments of inter-segment revenues.
[2] Includes $32 million in reductions to revenue related to amounts subject to refund resulting from the Tax Act ($27 million at Regulated Distribution and $5 million at Regulated Transmission).

	For the Three Months Ended March 31, 2018			
Revenues by Type of Service	Regulated Distribution	Regulated Transmission	Corporate/Other and Reconciling Adjustments [1]	Total
	(In millions)			
Distribution services[2]	$1,281	$ —	$ (12)	$1,269
Retail generation	1,040	—	(14)	1,026
Wholesale sales	123	—	5	128
Transmission[2]	—	319	—	319
Other	35	—	1	36
Total revenues from contracts with customers	$2,479	$ 319	$ (20)	$2,778
ARP	64	—	—	64
Other non-customer revenue	33	4	(17)	20
Total revenues	$2,576	$ 323	$ (37)	$2,862

[1] Includes eliminations and reconciling adjustments of inter-segment revenues.
[2] Includes $76 million in reductions to revenue related to amounts subject to refund resulting from the Tax Act ($72 million at Regulated Distribution and $4 million at Regulated Transmission).

Other non-customer revenue includes revenue from late payment charges of $11 million and $10 million, as well as revenue from derivatives of $2 million and $10 million, for the three months ended March 31, 2019 and 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 earns 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. Retail generation revenues are recognized over time as electricity is delivered and consumed immediately by the customer.

The following table represents a disaggregation of the Regulated Distribution segment revenue from contracts with distribution service and retail generation customers for the three months ended March 31, 2019 and 2018, by class:

	For the Three Months Ended March 31,	
Revenues by Customer Class	2019	2018
	(In millions)	
Residential	$1,484	$1,463
Commercial	587	580
Industrial	249	254
Other	24	24
Total Revenues	$2,344	$2,321

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 in the PJM markets 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 Consolidated 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 reverse 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 months ended March 31, 2019 and 2018, by transmission owner:

Revenues from Contracts with Customers by Transmission Asset Owner	For the Three Months Ended March 31, 2019	2018
	(In millions)	
ATSI	$174	$158
TrAIL	58	60
MAIT	49	30
Other	71	71
Total Revenues	$352	$319

3. DISCONTINUED OPERATIONS

FES, FENOC, BSPC and a portion of AE Supply (including the Pleasants Power Station), 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 Bankruptcy 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 had a controlling interest in the FES Debtors, 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 FirstEnergy has accounted and will account for its investments in FES and FENOC at fair values of zero. In connection with the disposal and the FES Bankruptcy settlement agreement approved by the Bankruptcy Court in September 2018, as further discussed in Note 1, "Organization and Basis of Presentation," FE recorded an after-tax gain on disposal of $435 million in 2018, which includes a $1.2 billion gain recorded in the first quarter of 2018.

By eliminating a significant portion of its competitive generation fleet with the deconsolidation of the FES Debtors, FirstEnergy has concluded the FES Debtors 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. Under the terms of the FES Bankruptcy settlement agreement, FE will release any and all claims against the FES Debtors with respect to the $500 million borrowed 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. Under the terms of the FES Bankruptcy settlement agreement, FE reinstated $88 million for 2018 estimated payments for NOLs applied against the FES Debtor’s position in the unregulated companies’ money pool prior to their withdrawal on March 16, 2018, which increased the amount the FES Debtors owed FE under the money pool to $92 million. 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 on March 31, 2018 and given the terms of the FES Bankruptcy settlement agreement, FE fully reserved the $92 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, under the terms of the FES Bankruptcy settlement agreement, FirstEnergy will release any and all claims against the FES Debtors with respect to the $92 million owed under the unregulated money pool and $102 million unsecured promissory note. For the three months ended March 31, 2019, approximately $9 million of interest was accrued and subsequently reserved.

Services Agreements

Pursuant to the FES Bankruptcy settlement agreement, FirstEnergy entered into an amended and restated shared services agreement with the FES Debtors to extend the availability of shared services until no later than June 30, 2020, subject to reductions in services if requested by the FES Debtors. Under the amended shared services agreement, and consistent with the prior shared services agreements, costs are directly billed or assigned at no more than cost. In addition to providing for certain notice requirements and other terms and conditions, the agreement provided for a credit to the FES Debtors in an amount up to $112.5 million for charges incurred for services provided under prior shared services agreements and the amended shared services agreement from April 1, 2018 through December 31, 2018. The entire credit for shared services provided to the FES Debtors ($112.5 million) has been recognized by FE and was included within loss from discontinued operations as of December 31, 2018. FES has paid approximately $35 million through March 31, 2019.

Benefit Obligations

FirstEnergy will retain certain obligations for the FES Debtors' employees for services provided prior to emergence from bankruptcy. The retention of this obligation at March 31, 2018, resulted in a net liability of $820 million (including EDCP, pension and OPEB) with a corresponding loss from discontinued operations. EDCP and pension/OPEB service costs earned by the FES Debtors' employees during bankruptcy are billed under the shared services agreement. As FE continues to provide pension benefits to FES/FENOC employees, all components of pension cost, including the mark to market, are seen as providing ongoing services and are reported in the continuing operations of FE, subsequent to the bankruptcy filing. FE has billed FES and FENOC $10 million for their share of pension and OPEB service costs for the three months ended March 31, 2019.

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 provides power to certain affiliates' facilities. As of March 31, 2019, the Utilities owed FES approximately $26 million related to these purchases. The terms and conditions of the power purchase agreements are generally consistent with industry practices and other similar third-party arrangements. The Utilities purchased and recognized in continuing operations approximately $83 million and $103 million of power purchases from FES for the three months ended March 31, 2019 and 2018, respectively.

Income Taxes

For U.S. federal income taxes, until emergence from bankruptcy, the FES Debtors 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 NOL as a future worthless stock deduction. FirstEnergy currently estimates a future worthless stock deduction of approximately $4.8 billion ($1.0 billion, net of tax) and is net of unrecognized tax benefits of $418 million ($88 million, net of tax). The estimated worthless stock deduction is contingent upon the emergence of the FES Debtors from the FES Bankruptcy and such amounts may be materially impacted by future events.

Additionally, discontinued operations include tax expense of approximately $14 million and $16 million in the first three months of 2019 and 2018, respectively, due to certain aspects of the Tax Act that only apply as a result of the FES Debtors remaining a part of FirstEnergy's consolidated tax return.

See Note 1, "Organization and Basis of Presentation", for further discussion of the settlement among FirstEnergy, the FES Key Creditor Groups, the FES Debtors and the UCC.

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. On March 1, 2018, AE Supply completed the sale of the Buchanan Generating Facility. On May 3, 2018, AE Supply and AGC completed the sale of approximately 59% of AGC's interest in Bath County. Also, on May 3, 2018, following the 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 Bankruptcy Court approved the sale on July 13, 2018, and the transaction was completed on July 31, 2018.

As contemplated under the FES Bankruptcy settlement agreement, AE Supply entered into an agreement on December 31, 2018, to transfer the 1,300 MW Pleasants Power Station and related assets to FG, while retaining certain specified liabilities. Under the terms of the agreement, FG acquired the economic interests in Pleasants as of January 1, 2019, and AE Supply will operate Pleasants until the transfer is completed. After closing, AE Supply will continue to provide access to the McElroy's Run CCR Impoundment Facility, which is not being transferred, and FE will provide certain guarantees for retained environmental liabilities of AE Supply, including the McElroy’s Run CCR Impoundment Facility. The transfer of the Pleasants Power Station is subject to

various customary and other closing conditions, including the effectiveness of a plan of reorganization for the FES Debtors in connection with the FES Bankruptcy. There can be no assurance that all closing conditions will be satisfied or that the transfer will be consummated.

Individually, the AE Supply and BSPC asset sales and Pleasants Power Station transfer did not qualify for reporting as discontinued operations. However, in the aggregate, the transactions 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 months ended March 31, 2019 and 2018, were as follows:

	For the Three Months Ended March 31,	
(In millions)	2019	2018
Revenues	$54	$736
Fuel	(35)	(164)
Purchased power	—	(58)
Other operating expenses	(10)	(369)
Provision for depreciation	—	(63)
General taxes	(4)	(23)
Other expense, net [1]	(2)	(62)
Income (Loss) from discontinued operations, before tax	3	(3)
Income tax expense	14	48
Loss from discontinued operations, net of tax	(11)	(51)
Gain (Loss) on disposal of FES and FENOC, net of tax	(24)	1,239
Income (Loss) from discontinued operations	$(35)	$1,188

[1] Other expense, net for the three months ended March 31, 2019, reflects FG's economic interests in Pleasants effective January 1, 2019, as further discussed above.

The gain (loss) on disposal of FES and FENOC recognized in the three months ended March 31, 2019 and 2018, consisted of the following:

	For the Three Months Ended March 31,	
(In millions)	2019	2018
Removal of investment in FES and FENOC	$—	$2,193
Assumption of benefit obligations retained at FE	—	(820)
Guarantees and credit support provided by FE	—	(139)
Reserve on receivables and allocated pension/OPEB mark-to-market	—	(914)
Settlement consideration and services credit	(33)	—
Gain (Loss) on disposal of FES and FENOC, before tax	(33)	320
Income tax benefit, including estimated worthless stock deduction	9	919
Gain (Loss) on disposal of FES and FENOC, net of tax	$(24)	$1,239

As of March 31, 2019, and December 31, 2018, material and supplies of $21 million and $25 million, respectively, are included in FirstEnergy's Consolidated Balance Sheets as Current assets - discontinued operations.

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FirstEnergy's Consolidated Statement of Cash Flows combines cash flows from discontinued operations with cash flows from continuing operations within each cash flow category. The following table summarizes the major classes of cash flow items as discontinued operations for the three months ended March 31, 2019 and 2018:

(In millions)	For the Three Months Ended March 31, 2019	2018
CASH FLOWS FROM OPERATING ACTIVITIES:		
Income (loss) from discontinued operations	$(35)	$1,188
Depreciation and amortization, including regulatory assets, net, intangible assets and deferred debt-related costs	—	64
Unrealized gain on derivative transactions	—	(10)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	—	(16)
Sales of investment securities held in trusts	—	109
Purchases of investment securities held in trusts	—	(122)

4. EARNINGS PER SHARE OF COMMON STOCK

The convertible preferred stock issued in January 2018 (see Note 9, "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 stock 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 stock 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 was 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 was reflected in net income attributable to common stockholders as a deemed dividend and was fully amortized in 2018.

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 March 31, 2019	2018
(In millions, except per share amounts)		
EPS of Common Stock		
Income from continuing operations	$355	$181
Less: Preferred dividends	(3)	(43)
Less: Amortization of beneficial conversion feature	—	(113)
Less: Undistributed earnings allocated to preferred stockholders[1]	(2)	—
Income from continuing operations available to common stockholders	350	25
Discontinued operations, net of tax	(35)	1,188
Less: Undistributed earnings allocated to preferred stockholders [1]	—	—
Income (loss) from discontinued operations available to common stockholders	(35)	1,188
Income available to common stockholders, basic and diluted	$315	$1,213
Share Count information:		
Weighted average number of basic shares outstanding	530	476
Assumed exercise of dilutive stock options and awards	3	2
Weighted average number of diluted shares outstanding	533	478
Income (loss) available to common stockholders, per common share:		
Income from continuing operations, basic	$0.66	$0.05
Discontinued operations, basic	(0.07)	2.50
Income available to common stockholders, basic	$0.59	$2.55
Income from continuing operations, diluted	$0.66	$0.05
Discontinued operations, diluted	(0.07)	2.49
Income available to common stockholders, diluted	$0.59	$2.54

(1) Undistributed earnings were not allocated to participating securities for the three months ended March 31, 2018, as income from continuing operations less dividends declared (common and preferred) and deemed dividends were a net loss. Discontinued operations undistributed earnings allocated to preferred stockholders for the three months ended March 31, 2019, were less than $500 thousand.

For the three months ended March 31, 2018, 1 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. For the three months ended March 31, 2019, no shares from stock options and awards were excluded from the calculation of diluted shares outstanding. Also, 8 million and 59 million shares associated with the assumed conversion of preferred stock were excluded as of March 31, 2019 and 2018, respectively, 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 were as follows:

Components of Net Periodic Benefit Costs (Credits)	Pension		OPEB	
For the Three Months Ended March 31,	2019	2018	2019	2018
	(In millions)			
Service costs [1]	$48	$56	$1	$1
Interest costs [2]	93	93	5	6
Expected return on plan assets [2]	(135)	(144)	(7)	(8)
Amortization of prior service costs (credits) [2]	2	2	(9)	(20)
Special termination costs [2]	15	—	—	—
Net periodic costs (credits), including amounts capitalized	$23	$7	$(10)	$(21)
Net periodic costs (credits), recognized in earnings	$6	$(14)	$(10)	$(21)

[1] Service costs, net of capitalization, are reported within Other operating expenses on FirstEnergy's Consolidated Statements of Income.
[2] Non-service costs are reported within Miscellaneous income, net, within Other Income (Expense) on FirstEnergy's Consolidated Statements of Income.

Amounts in the tables above include FES and FENOC's share of the net periodic pension and OPEB costs (credits) of $11 million and $(1) million, respectively, for the three months ended March 31, 2019. FES and FENOC's share of the net periodic pension and OPEB costs (credits) were $13 million and $(10) million, respectively, for the three months ended March 31, 2018. The 2018 amounts and 2019 special termination costs associated with FES' voluntary enhanced retirement package are a component of Discontinued Operations in FirstEnergy's Consolidated Statements of Income. Following FES and FENOC’s voluntary bankruptcy filing and resolution of certain disputed pension and service charges discussed in Note 1, "Organization and Basis of Presentation", FE has billed FES and FENOC $10 million for their share of pension and OPEB service costs for the three months ended March 31, 2019.

On February 1, 2019, FirstEnergy made a $500 million voluntary cash contribution to the qualified pension plan. As a result of this contribution, FirstEnergy expects no required contributions through 2021.

6. ACCUMULATED OTHER COMPREHENSIVE INCOME

The changes in AOCI for the three months ended March 31, 2019 and 2018, for FirstEnergy are shown in the following table:

	Gains & Losses on Cash Flow Hedges	Unrealized Gains on AFS Securities	Defined Benefit Pension & OPEB Plans	Total
	(In millions)			
AOCI Balance, January 1, 2019	$(11)	$ —	$ 52	$41
Amounts reclassified from AOCI	1	—	(7)	(6)
Other comprehensive income (loss)	1	—	(7)	(6)
Income tax benefits on other comprehensive income (loss)	—	—	(1)	(1)
Other comprehensive income (loss), net of tax	1	—	(6)	(5)
AOCI Balance, March 31, 2019	$(10)	$ —	$ 46	$36

AOCI Balance, January 1, 2018	$(22)	$ 67	$ 97	$142
Other comprehensive income before reclassifications	—	(97)	—	(97)
Amounts reclassified from AOCI	2	(1)	(18)	(17)
Deconsolidation of FES and FENOC	13	(8)	—	5
Other comprehensive income (loss)	15	(106)	(18)	(109)
Income tax (benefits) on other comprehensive income (loss)	8	(39)	(22)	(53)
Other comprehensive income (loss), net of tax	7	(67)	4	(56)
AOCI Balance, March 31, 2018	$(15)	$ —	$ 101	$86

The following amounts were reclassified from AOCI for FirstEnergy in the three months ended March 31, 2019 and 2018:

Reclassifications from AOCI[1]	For the Three Months Ended March 31, 2019	2018 [2]	Affected Line Item in Consolidated Statements of Income
	(In millions)		
Gains & losses on cash flow hedges			
Commodity contracts	$ —	$ 1	Other operating expenses
Long-term debt	1	1	Interest expense
	—	(1)	Income taxes
	$ 1	$ 1	Net of tax
Unrealized gains on AFS securities			
Realized gains on sales of securities	$ —	$ (1)	Discontinued Operations
Defined benefit pension and OPEB plans			
Prior-service costs	$ (7)	$ (18)	[3]
	1	5	Income taxes
	$ (6)	$ (13)	Net of tax

[1] Amounts in parenthesis represent credits to the Consolidated Statements of Income from AOCI.
[2] 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".
[3] Components are included in the computation of net periodic pension cost. See Note 5, "Pension and Other Postemployment Benefits," for additional details.

7. INCOME TAXES

FirstEnergy’s interim effective tax rates reflect the estimated annual effective tax rates for 2019 and 2018. These tax rates are affected by estimated annual permanent items, such as AFUDC equity and other flow-through items, as well as discrete items that may occur in any given period, but are not consistent from period to period.

FirstEnergy's effective tax rate for the three months ended March 31, 2019 and 2018 was 20.8% and 56.3%, respectively. The higher effective tax rate in 2018 was primarily due to a one-time charge of $126 million to income tax expense in continuing operations associated with the re-measurement of West Virginia state deferred income taxes, resulting from the legal and financial separation of FES and FENOC from FirstEnergy, which occurred in the first quarter of 2018. See Note 3, "Discontinued Operations" for other tax matters relating to the FES Bankruptcy that were recognized in discontinued operations. Furthermore, starting in 2018, FirstEnergy’s regulated entities began amortizing the net excess deferred income taxes, which resulted in a net income tax benefit, reducing the effective tax rate. See Note 13, “Regulatory Matters,” for additional detail.

During the three months ended March 31, 2019, FirstEnergy increased its reserve for uncertain tax benefits by approximately $5 million, none of which had an impact to the effective tax rate as the full amount was recorded within discontinued operations. As of March 31, 2019, it is reasonably possible that FirstEnergy could record a net decrease to its reserve for uncertain tax positions by approximately $45 million within the next twelve months due to the statute of limitations expiring or resolution with taxing authorities, of which approximately $40 million would impact FirstEnergy's effective tax rate.

8. LEASES

FirstEnergy primarily leases vehicles as well as building space, office equipment, and other property and equipment under cancelable and noncancelable leases. FirstEnergy does not have any material leases in which it is the lessor.

FirstEnergy adopted ASU 2016-02, "Leases (Topic 842)" on January 1, 2019, and elected a number of transitional practical expedients provided within the standard. These included a "package of three" expedients that must be taken together and allowed entities to (1) not reassess whether existing contracts contain leases, (2) carryforward the existing lease classification, and (3) not reassess initial direct costs associated with existing leases. In addition, FirstEnergy elected the option to apply the requirements of the standard in the period of adoption (January 1, 2019) with no restatement of prior periods. Adoption of the standard on January 1, 2019, did not result in a material cumulative effect adjustment upon adoption. FirstEnergy did not evaluate land easements under the new guidance as they were not previously accounted for as leases. FirstEnergy also elected not to separate lease components from non-lease components as non-lease components were not material.

Leases with an initial term of 12 months or less are recognized as lease expense on a straight-line basis over the lease term and not recorded on the balance sheet. Most leases include one or more, options to renew, with renewal terms that can extend the lease term from 1 to 40 years, and certain leases include options to terminate. The exercise of lease renewal options is at FirstEnergy's sole discretion. Renewal options are included within the lease liability if they are reasonably certain based on various factors relative to the contract. Certain leases also include options to purchase the leased property. The depreciable life of leased assets and leasehold improvements are limited by the expected lease term, unless there is a transfer of title or purchase option reasonably certain of exercise. FirstEnergy's lease agreements do not contain any material restrictive covenants.

For vehicles leased under master lease agreements, the lessor is guaranteed a residual value up to a stated percentage of the equipment cost at the end of the lease term. As of March 31, 2019, the maximum potential loss for these lease agreements at the end of the lease term is approximately $16 million.

Finance leases for assets used in regulated operations are recognized in FirstEnergy's Consolidated Statements of Income such that amortization of the right-of-use asset and interest on lease liabilities equals the expense allowed for ratemaking purposes. Finance leases for non-regulated assets are accounted for as if the assets were owned and financed, with associated expense recognized in Interest expense and Provision for depreciation. All operating lease expenses are recognized in Other operating expense. The components of lease expense were as follows:

	For the Three Months Ended March 31, 2019			
(In millions)	Vehicles	Buildings	Other	Total
Operating lease costs [1]	$7	$ 2	$ 3	$ 12
Finance lease costs:				
Amortization of right-of-use assets	4	—	1	5
Interest on lease liabilities	1	1	—	2
Total finance lease cost	5	1	1	7
Total lease cost	$12	$ 3	$ 4	$ 19

[1] Includes $4 million of short-term lease costs.

Lease terms and discount rates were as follows:

	As of March 31, 2019
Weighted-average remaining lease terms (years)	
Operating leases	8.71
Finance leases	4.89
Weighted-average discount rate [1]	
Operating leases	4.96 %
Finance leases	3.44 %

[1] When an implicit rate is not readily determinable, an incremental borrowing rate is utilized, determining the present value of lease payments. The rate is determined based on expected term and information available at the commencement date.

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Supplemental balance sheet information related to leases was as follows:

(In millions)	Financial Statement Line Item	As of March 31, 2019
Assets		
Operating lease assets, net of accumulated amortization of $5 million	Deferred charges and other assets	$ 187
Finance lease assets, net of accumulated amortization of $87 million	Property, plant and equipment	77
Total leased assets		$ 264
Liabilities		
Current:		
Operating	Other current liabilities	$ 29
Finance	Currently payable long-term debt	16
Noncurrent:		
Operating	Other noncurrent liabilities	190
Finance	Long-term debt and other long-term obligations	55
Total leased liabilities		$ 290

Supplemental cash flow information related to leases was as follows:

(In millions)	For the Three Months Ended March 31, 2019
Cash paid for amounts included in the measurement of lease liabilities	
Operating cash flows from operating leases	$ 8
Operating cash flows from finance leases	1
Finance cash flows from finance leases	4
Right-of-use assets obtained in exchange for lease obligations:	
Operating leases	$ 6
Finance leases	1

Maturities of lease liabilities as of March 31, 2019, were as follows:

(In millions)	Operating Leases	Finance Leases	Total
2019	$ 24	$ 16	$40
2020	36	19	55
2021	34	17	51
2022	33	14	47
2023	30	8	38
2024	25	4	29
Thereafter	95	12	107

Total lease payments [1]	277	90	367
Less imputed interest	(58)	(19)	(77)
Total net present value	$ 219	$ 71	$290

[1] Operating lease payments for certain leases are offset by sublease receipts of $30 million over 14 years.

As of March 31, 2019, additional operating leases agreements, primarily for vehicles, that have not yet commenced are $15 million. These leases are expected to commence in 2019 with lease terms of 3 to 10 years.

The future minimum capital lease payments as of December 31, 2018, as reported in the 2018 Form 10-K under ASC 840, are as follows:

Capital Leases

	(In millions)
2019	$ 24
2020	19
2021	16
2022	13
2023	8
Years thereafter	16
Total minimum lease payments	96
Interest portion	(23)
Present value of net minimum lease payments	73
Less current portion	18
Noncurrent portion	$ 55

The future minimum operating lease payments as of December 31, 2018, as reported in the 2018 Form 10-K under ASC 840 are as follows:

Operating Leases

	(In millions)
2019	$ 34
2020	36
2021	34
2022	30
2023	28
Years thereafter	127
Total minimum lease payments	$ 289

9. CAPITALIZATION

Stockholders' Equity

The changes in stockholders' equity for the three months ended March 31, 2019 and 2018, for FirstEnergy are included in the following tables:

	Series A Convertible Preferred Stock		Common Stock		OPIC	AOCI	Accumulated Deficit	Total Stockholders' Equity
(In millions)	Shares	Amount	Shares	Amount				
Balance, January 1, 2019	0.7	$ 71	512	$ 51	$11,530	$ 41	$ (4,879)	$ 6,814
Net income							320	320
Other comprehensive loss, net of tax						(5)		(5)
Stock-based compensation					7			7
Stock Investment Plan and certain share-based benefit plans			1		1			1
Cash dividends declared on common stock					(202)			(202)
Cash dividends declared on preferred stock					(3)			(3)
	(0.5)	(50)	18	2	48			—

Conversion of Series A Convertible Preferred Stock								
Balance, March 31, 2019	0.2	$ 21	531	$ 53	$11,381	$ 36	$ (4,559)	$ 6,932

(In millions)	Series A Convertible Preferred Stock Shares	Amount	Common Stock Shares	Amount	OPIC	AOCI	Accumulated Deficit	Total Stockholders' Equity
Balance, January 1, 2018	—	$ —	445	$ 44	$10,001	$142	$ (6,262)	$ 3,925
Net income							1,369	1,369
Other comprehensive loss, net of tax						(56)		(56)
Stock-based compensation					19			19
Stock Investment Plan and certain share-based benefit plans			2	1	5			6
Cash dividends declared on common stock					(343)			(343)
Cash dividends declared on preferred stock					(42)			(42)
Stock issuance [1]	1.6	162	30	3	2,297			2,462
Impact of adopting new accounting pronouncements [2]							35	35
Balance, March 31, 2018	1.6	$ 162	477	$ 48	$11,937	$86	$ (4,858)	$ 7,375

[1] The preferred stock included an embedded conversion option at a price that was below the fair value of the Common Stock on the commitment date. This beneficial conversion feature (BCF), which was approximately $296 million, was recorded to OPIC as well as the amortization of the BCF (deemed dividend of $113 million for the three months ended March 31, 2018) through the period from the issue date to the first allowable conversion date (July 22, 2018). There is no net impact to OPIC for the three months ended March 31, 2018. Please see below for additional information on the issuance.

[2] FirstEnergy adopted ASU 2016-01, "Financial Instruments-Overall: Recognition and Measurement of Financial Assets and Financial Liabilities" standard on January 1, 2018, and subsequently recorded a cumulative effect adjustment to retained earnings of $57 million representing unrealized gains on equity securities with FES NDTs that were previously recorded to AOCI. In addition, FirstEnergy adopted ASU 2018-02, "Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income" and upon adoption, 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. These amounts are offset in other comprehensive loss and do not have an impact on total stockholders' equity.

Dividends declared for each share of common stock and as-converted share of preferred stock was $0.38 and $0.72 during the first quarter of 2019 and 2018, respectively.

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 is convertible at the option of the holders 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 March 31, 2019, the Conversion Price in effect was $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. During 2018, 911,411 of preferred shares were converted into 33,238,910 common shares at the option of the preferred holders. Also at the option of the shareholders, 494,767 preferred shares were converted into 18,044,018 common shares in January 2019, resulting in 209,822 preferred shares outstanding and yet to be converted as of March 31, 2019.

In general, any shares of preferred stock outstanding on July 22, 2019, will be automatically converted. Further, 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. 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 FE 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 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 was 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 months ended March 31, 2018, was approximately $113 million. The BCF was fully amortized as of December 31, 2018.

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.

10. 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 March 31, 2019, and December 31, 2018, $280 million and $292 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 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 March 31, 2019, and December 31, 2018, $37 million and $41 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 March 31, 2019, and December 31, 2018, $346 million and $358 million of the environmental control bonds were outstanding, respectively.

Unconsolidated VIEs

FirstEnergy is not the primary beneficiary of the following VIEs:

- Global Holding - FEV holds a 33-1/3% equity ownership in Global Holding, the holding company for a joint venture in the Signal Peak mining and coal transportation operations with coal sales in U.S. and international markets. FEV is not the

primary beneficiary of the joint venture, as it does not have control over the significant activities affecting the joint ventures economic performance. FEV's ownership interest is subject to the equity method of accounting. As of March 31, 2019, the carrying value of the equity method investment was zero.

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 $188 million as of March 31, 2019. 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 March 31, 2019, 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 11 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 March 31, 2019 and 2018, were $31 million and $32 million, 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. The carrying values of the equity investments in FES and FENOC were zero at March 31, 2019.

11. 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 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. Significant increases or decreases in inputs in isolation may have resulted in a higher or lower fair value measurement. See Note 12, "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. Significant increases or decreases in inputs in isolation may have resulted 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 March 31, 2019, from those used as of December 31, 2018. 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.

The following tables set forth the recurring assets and liabilities that are accounted for at fair value by level within the fair value hierarchy:

	March 31, 2019				December 31, 2018			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets	(In millions)							
Corporate debt securities	$—	$416	$—	$416	$—	$405	$—	$405
Derivative assets FTRs[1]	—	—	—	—	—	—	10	10
Equity securities[2]	384	—	—	384	339	—	—	339
Foreign government debt securities	—	16	—	16	—	13	—	13
U.S. government debt securities	—	29	—	29	—	20	—	20
U.S. state debt securities	—	256	—	256	—	250	—	250
Other[3]	174	34	—	208	367	34	—	401
Total assets	$558	$751	$—	$1,309	$706	$722	$10	$1,438
Liabilities								
Derivative liabilities FTRs[1]	$—	$—	$(1)	$(1)	$—	$—	$(1)	$(1)
Derivative liabilities NUG contracts[1]	—	—	(41)	(41)	—	—	(44)	(44)
Total liabilities	$—	$—	$(42)	$(42)	$—	$—	$(45)	$(45)
Net assets (liabilities)[4]	$558	$751	$(42)	$1,267	$706	$722	$(35)	$1,393

(1) 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 $4 million as of March 31, 2019 and December 31, 2018, 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 March 31, 2019, and December 31, 2018:

	NUG Contracts[1]			FTRs[1]		
	Derivative Assets	Derivative Liabilities	Net	Derivative Assets	Derivative Liabilities	Net
	(In millions)					
January 1, 2018 Balance	$—	$ (79)	$(79)	$3	$ —	$3
Unrealized gain	—2		2	8	1	9
Purchases	——		—	5	(5)	—
Settlements	—33		33	(6)	3	(3)
December 31, 2018 Balance	$—	$ (44)	$(44)	$10	$ (1)	$9
Unrealized loss	—(7)		(7)	—	—	—
Purchases	——		—	—	—	—
Settlements	—10		10	(10)	—	(10)
March 31, 2019 Balance	$—	$ (41)	$(41)	$—	$ (1)	$(1)

(1)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 March 31, 2019:

	Fair Value, Net (In millions)	Valuation Technique	Significant Input	Range	Weighted Average	Units
FTRs	$ (1)	Model	RTO auction clearing prices	$(1.00) to $1.90	$0.40	Dollars/MWH
NUG Contracts	$ (41)	Model	Generation	400 to 996,000	205,000	MWH
			Regional electricity prices	$30.80 to $33.40	$32.10	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 March 31, 2019, and December 31, 2018:

	March 31, 2019[1]				December 31, 2018[1]			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
	(In millions)							
Debt securities	$723	$ 10	$ (16)	$ 717	$714	$ 2	$ (28)	$ 688
Equity securities	$343	$ 41	$ (3)	$ 381	$339	$ 15	$ (16)	$ 338

[1] Excludes short-term cash investments of $4 million and $20 million at March 31, 2019 and December 31, 2018, respectively

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 months ended March 31, 2019 and 2018, were as follows:

	For the Three Months Ended March 31,	
	2019	2018
Sale Proceeds	$153	$191
Realized Gains	7	19
Realized Losses	(6)	(16)
Interest and Dividend Income	9	10

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 $257 million and $253 million as of March 31, 2019, and December 31, 2018, respectively, 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 long-term debt, which excludes capital lease obligations and net unamortized debt issuance costs, premiums and discounts as of March 31, 2019 and December 31, 2018:

	March 31, 2019	December 31, 2018
	(In millions)	
Carrying Value [1]	$19,088	$ 18,315
Fair Value	$20,691	$ 19,266

[1] The carrying value for the first quarter 2019 includes $1.4 billion of debt issuances at ME, JCP&L and FET.

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 March 31, 2019, and December 31, 2018.

12. 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 $14 million and $15 million as of March 31, 2019 and December 31, 2018, respectively. Based on current estimates, approximately $2 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 months ended March 31, 2019 and 2018.

As of March 31, 2019, and December 31, 2018, 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 March 31, 2019, and December 31, 2018, 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 as of March 31, 2019 and December 31, 2018.

NUGs

As of March 31, 2019, and December 31, 2018, FirstEnergy's net liability position under NUG contracts was $41 million and $44 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 months ended March 31, 2019, there were settlements of $10 million and unrealized losses of $(7) million. Changes in the fair value of NUG

contracts are subject to regulatory accounting treatment and do not impact earnings.

FTRs

As of March 31, 2019, and December 31, 2018, FirstEnergy's net asset (liability) position associated with FTRs was $(1) million and $9 million, respectively. 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. During the three months ended March 31, 2019, there were settlements of $10 million.

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. Further, 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.

MARYLAND

PE operates under MDPSC approved base rates that were effective as of March 23, 2019. PE also 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 EmPOWER Maryland program requires each electric utility to file a plan to reduce electric consumption and demand 0.2% per year, 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 2016 starting goal under this requirement was 0.97%. 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. 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.

In 2013, the MDPSC required 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 submitted analysis projected that it would require up to 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 MDPSC's scenarios. The MDPSC conducted a hearing in September 2014, but has not taken further action on this matter.

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 in connection with a 2016 MDPSC 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. PE proposed an electric vehicle charging infrastructure program at a projected total cost of $12 million, to be recovered over a five-year amortization. On January 14, 2019, the MDPSC approved the petition subject to certain reductions in the scope of the program.

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 must track and apply regulatory accounting treatment for the impacts beginning January 1, 2018, and subsequently submitted a report to the MDPSC, estimating that the Tax Act impacts would be approximately $7 million to $8 million annually for PE’s customers. On October 5, 2018, the MDPSC issued an order requiring PE to provide its customers a one-time credit for tax savings through September 30, 2018, which totaled approximately $5 million, and reserved all other Tax Act impacts to be resolved in the pending rate case. In the rate case order issued on March 22, 2019, the MDPSC directed that a further final one-time credit of $3 million be provided to PE's customers within two billing cycles.

On August 24, 2018, PE filed a base rate case with the MDPSC, which it supplemented on October 22, 2018, to update the partially forecasted test year with a full twelve months of actual data. The rate case requested an annual increase in base distribution rates of $19.7 million, plus creation of an EDIS to fund four enhanced service reliability programs. In responding to discovery, PE revised its request for an annual increase in base rates to $17.6 million. The

proposed rate increase reflects $7.3 million in annual savings for customers resulting from the recent federal tax law changes. On March 22, 2019, the MDPSC issued a final order that approved a rate increase of $6.2 million, approved three of the four EDIS programs for four years, directed PE to file a new depreciation study within 18 months, and ordered the filing of a new base rate case in four years to correspond to the ending of the approved EDIS programs.

NEW JERSEY

JCP&L operates under NJBPU approved rates that were effective as of January 1, 2017. JCP&L 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. All New Jersey EDCs participate in this competitive BGS procurement process and recover BGS costs directly from customers as a charge separate from base rates.

In December 2017, the NJBPU issued proposed rules to modify its current CTA policy in base rate cases to: (i) calculate savings using a five-year look back from the beginning of the test year; (ii) allocate savings with 75% retained by the company and 25% allocated to rate payers; and (iii) exclude transmission assets of electric distribution companies in the savings calculation, which were published in the NJ Register in the first quarter of 2018. JCP&L filed comments supporting the proposed rulemaking. On January 17, 2019, the NJBPU approved the proposed CTA rules with no changes.

Also in December 2017, 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. On January 23, 2019, the NJBPU granted JCP&L's request to temporarily suspend the procedural schedule in the matter pending settlement discussions. On April 23, 2019, JCP&L filed a Stipulation of Settlement with the NJBPU on behalf of the JCP&L, Rate Counsel, NJBPU Staff and New Jersey Large Energy Users Coalition, which provides that JCP&L will invest up to approximately $97 million in capital in its electric distribution system beginning on June 1, 2019 and continuing through December 31, 2020. The capital investments will occur in incremental projects that fall under the following three categories: (i) Overhead Circuit Reliability and Resiliency; (ii) Substation Reliability Enhancement; and (iii) Distribution Automation. JCP&L shall seek recovery of the capital investment through an accelerated cost recovery mechanism, provided for in the rules, that includes a revenue adjustment calculation and a process for two rate adjustments. JCP&L expects a NJBPU decision in May 2019.

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.

OHIO

The Ohio Companies currently operate under ESP IV through May 31, 2024. ESP IV includes Rider DMR, which provides for the Ohio Companies to collect $132.5 million annually for three years beginning in 2017, with the possibility of a two-year extension and is 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. On February 1, 2019, the Ohio Companies filed with the PUCO an application requesting a two-year extension of Rider DMR at the same amount and conditions.

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 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. ESP IV also includes: (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 was filed in February 2016, and remains pending as part of the grid modernization settlement described below; (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 Council 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 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. 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. The Ohio Companies then 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, which the PUCO denied. In October 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. The Ohio Companies intervened in the appeal, and additional parties subsequently filed notices of appeal with the Supreme Court of Ohio challenging various PUCO entries on their applications for rehearing. On September 26, 2018, the Supreme Court of Ohio denied a July 30, 2018 joint motion filed by the OCC, the NOAC, and the OMAEG to stay the portions of the PUCO's orders and entries under appeal that authorized Rider DMR. Oral argument on the appeals was held on January 9, 2019.

Under Ohio law, the Ohio Companies are required to implement energy efficiency programs that achieve certain annual energy savings and total peak demand reductions. The Ohio Companies' 2017-2019 plan, as proposed in April 2016, includes 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. In December 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 proposed plans 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. On December 21, 2017, the Ohio Companies filed an application for rehearing challenging the PUCO's modifications, which the PUCO denied on January 10, 2018. On March 12, 2018, the Ohio Companies appealed to the Supreme Court of Ohio challenging the PUCO's imposition of a 4% cost cap. Various other parties also appealed challenging various PUCO entries on their applications for rehearing. Oral argument on the appeals was held on February 20, 2019.

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. On November 9, 2018, the Ohio Companies filed a settlement agreement that provides for the implementation of the first phase of grid modernization plans, including the investment of $516 million over three years to modernize the Ohio Companies' electric distribution system, and for all tax savings associated with the Tax Act, discussed below, to flow back to customers. On January 25, 2019, the Ohio Companies filed a supplemental settlement agreement that keeps intact the provisions of the settlement described above and adds further customer benefits and protections, which broadened support for the settlement. The settlement has broad support, including PUCO Staff, the OCC, representatives of industrial and commercial customers, a low-income advocate, environmental advocates, hospitals, competitive generation suppliers and other parties. The PUCO conducted a hearing and the settlement agreement remains subject to PUCO approval.

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. On October 24, 2018, the PUCO entered an Order in its investigation into the impacts of the Tax Act on Ohio's utilities directing that by January 1, 2019, all Ohio rate-regulated utility companies, unless ordered otherwise, file applications not for an increase in rates to reflect the impact of the Tax Act on each specific utility's current rates. On October 30, 2018, the Ohio Companies filed an application to open a new proceeding for the implementation of matters relating to the impact of the Tax Act. As discussed further above, on November 9, 2018, the Ohio Companies filed a settlement agreement that provides for all tax savings associated with the Tax Act to flow back to customers and for the implementation of the first phase of grid modernization plans. As part of the agreement, the Ohio Companies also filed an application for approval of a rider to return the remaining tax savings to customers following PUCO approval of the settlement. On December 19, 2018, the PUCO upheld its January 10, 2018 ruling that utilities should be required to establish a deferred tax liability, effective January 1, 2018, in response to the Tax Act. On January 25, 2019, the Ohio Companies filed a supplemental settlement agreement that keeps intact the provisions of the settlement described above and adds further customer benefits and protections, which broadened support for the settlement. The PUCO conducted a hearing and the settlement agreement remains subject to PUCO approval.

The Ohio Companies' Rider NMB is designed to recover non-market-based transmission-related costs imposed on or charged to the Ohio Companies by FERC or PJM. On December 14, 2018, the Ohio Companies filed an application for a review of their 2019 Rider NMB, including recovery of future Legacy RTEP costs and previously absorbed Legacy RTEP costs, net of refunds received from PJM. On February 27, 2018, the PUCO issued an Order directing the Ohio Companies to file revised final tariffs recovering Legacy RTEP costs incurred since May 31, 2018, but excluding recovery of approximately $95 million in Legacy RTEP costs incurred prior to May 31, 2018, net of

refunds received from PJM. The PUCO solicited comments on whether the Ohio Companies should be permitted to recover the Legacy RTEP charges incurred prior to May 31, 2018. The Ohio Companies, OCC and OMAEG filed comments on March 29, 2019. The Ohio Companies filed reply comments on April 15, 2019.

PENNSYLVANIA

The Pennsylvania Companies operate under rates approved by the PPUC, effective as of January 27, 2017. These rates were adjusted for the net impact of the Tax Act, effective March 15, 2018. The net impact of the Tax Act for the period January 1, 2018 through March 14, 2018 must also be separately tracked for treatment in a future rate proceeding. 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.

The Pennsylvania Companies' DSPs for the June 1, 2019 through May 31, 2023 delivery period were approved by the PPUC in September 2018. Under the 2019-2023 DSPs, the supply will 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 also include modifications to the Pennsylvania Companies’ POR programs in order to continue their clawback pilot program as a long-term, permanent program term, 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. The PPUC directed a working group to further discuss the implementation of customer assistance program shopping limitations and appropriate scripting for the Pennsylvania Companies' customer referral programs, and in November 2018, issued a subsequent order to approve additional customer assistance program shopping parameters and further limit the scope of the working group discussion. On December 21, 2018, the PPUC issued a tentative order proposing a model to incorporate the directed shopping restrictions. Comments on the proposal were filed January 22, 2019. On February 28, 2019, the PPUC issued a final order approving the Pennsylvania Companies' proposal on customer assistance programs shopping limitations and directing script modifications to the Pennsylvania Companies' customer referral programs.

Pursuant to Pennsylvania Act 129 of 2008 and PPUC orders, Pennsylvania EDCs implement energy efficiency and peak demand reduction programs. 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.

Pennsylvania EDCs may establish a DSIC to recover costs of infrastructure improvements and costs related to highway relocation projects with PPUC approval. LTIIPs outlining infrastructure improvement plans for PPUC review and approval must be filed prior to approval of a DSIC. 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. On September 20, 2018, following a periodic review of the LTIIPs as required by regulation once every five years, the PPUC entered an Order concluding that the Pennsylvania Companies have substantially adhered to the schedules and expenditures outlined in their LTIIPs, but that changes to the LTIIPs as designed are necessary to maintain and improve reliability and directed the Pennsylvania Companies to file modified or new LTIIPs. On January 18, 2019, the Pennsylvania Companies filed modifications to their current LTIIPs that would terminate those LTIIPs at the end of 2019, and proposed revised LTIIP spending in 2019 of approximately $45 million by ME, $25 million by PN, $26 million by Penn and $51 million by WP. The Pennsylvania Companies also committed to making filings later in 2019, which would propose new LTIIPs for the 2020 through 2024 period.

The Pennsylvania Companies' approved DSIC riders for quarterly cost recovery went into effect July 1, 2016, subject to hearings and refund or reallocation among customer classes. In the January 19, 2017 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 April 19, 2018, the PPUC approved the Joint Settlement without modification and reversed the ALJ's previous 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 the Commonwealth Court. Briefing is complete and oral argument is scheduled for June 3, 2019.

WEST VIRGINIA

MP and PE provide electric service to all customers through traditional cost-based, regulated utility ratemaking and operates under rates approved by the WVPSC effective February 2015. 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 August 31, 2018, MP and PE filed a $100.9 million decrease in their ENEC rates proposed to be effective January 1, 2019, which included a $25.6 million annual decrease impact associated with the settlement regarding the impact of the Tax Act on West Virginia rates, as noted below. Additionally, the August 31, 2018 filing included an elimination of the Energy Efficiency Cost Rate Surcharge effective January 1, 2019, equating to an additional $2.1 million decrease. The rate decreases represent an approximate 7.2% annual decrease in rates versus those in effect on August 31, 2018. A unanimous settlement was filed with the WVPSC on November 20, 2018, and a hearing was held on November 27, 2018. An order adopting the settlement in full without modification was issued on January 2, 2019.

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, and record as a regulatory liability, the tax savings resulting from the Tax Act on a monthly basis, effective January 1, 2018. As a result of a WVPSC-approved settlement on August 24, 2018, MP and PE began to flow through to customers $25.6 million in rate reduction beginning September 1, 2018, and to defer to the next base rate case (or a separate proceeding if a base rate case is not filed by August 31, 2020) the amount and classification of the excess ADITs resulting from the Tax Act and the issue of whether MP and PE should be required to credit to customers any of the reduced income tax expense occurring between January 1, 2018 and August 31, 2018.

FERC REGULATORY MATTERS

Under the FPA, FERC regulates rates for interstate wholesale sales, transmission of electric power, accounting and other matters, including construction and operation of hydroelectric projects. With respect to their wholesale services and rates, the Utilities, AE Supply, AGC, and the Transmission Companies are subject to regulation by FERC. FERC regulations require JCP&L, MP, PE, WP

and the Transmission Companies to provide open access transmission service at FERC-approved rates, terms and conditions. Transmission facilities of JCP&L, MP, PE, WP and the Transmission Companies are subject to functional control by PJM and transmission service using their transmission facilities is provided by PJM under the PJM Tariff.

FERC regulates the sale of power for resale in interstate commerce in part by granting authority to public utilities to sell wholesale power at market-based rates upon showing that the seller cannot exert market power in generation or transmission or erect barriers to entry into markets. The Utilities and AE Supply each have been authorized by FERC to sell wholesale power in interstate commerce at market-based rates and have a market-based rate tariff on file with FERC, although major wholesale purchases remain subject to regulation by the relevant state commissions.

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, and the Transmission Companies. 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 the facilities that FirstEnergy operates 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.

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. In a subsequent order, FERC affirmed its prior ruling that ATSI must submit the cost/benefit analysis. ATSI is evaluating the cost/benefit approach.

FERC Actions on Tax Act

On March 15, 2018, FERC issued a NOI seeking information regarding whether and how FERC should address possible changes to ADIT and bonus depreciation as a result of the Tax Act. Such possible changes could impact FERC-jurisdictional rates, including transmission rates. On November 15, 2018, FERC issued a NOPR suggesting mechanisms to revise transmission rates to address the Tax Act’s effect on ADIT. Specifically, FERC proposed utilities with transmission formula rates would include mechanisms to (i) deduct any excess ADIT from or add any deficient ADIT to their rate bases; (ii) raise or lower their income tax allowances by any amortized excess or deficient ADIT; and (iii) incorporate a new permanent worksheet into their rates that will annually track information related to

excess or deficient ADIT. Utilities with transmission stated rates would determine the amount of excess and deferred income tax caused by the reduced federal corporate income tax rate and return or recover this amount to or from customers. To assist with implementation of the proposed rule, FERC also issued on November 15, 2018, a policy statement providing accounting and ratemaking guidance for treatment of ADIT for all FERC-jurisdictional public utilities. The policy statement also addresses the accounting and ratemaking treatment of ADIT following the sale or retirement of an asset after December 31, 2017. FESC, on behalf of its affiliated transmission owners, supported comments submitted by Edison Electric Institute requesting additional clarification on the ratemaking and accounting treatment for ADIT in formula and stated transmission rates. FERC's final rule remains pending.

Transmission ROE Methodology

In June 2014, FERC issued Opinion No. 531 revising its approach for calculating the discounted cash flow element of FERC’s ROE methodology and announcing the potential for a qualitative adjustment to the ROE methodology results. Parties appealed to the D.C. Circuit, and on April 14, 2017, that court issued a decision vacating FERC’s order and remanding the matter to FERC for further review. On October 16, 2018, FERC issued its order on remand, in which it proposed a revised ROE methodology. Specifically, in complaint proceedings alleging that an existing ROE is not just and reasonable, FERC proposes to rely on three financial models-discounted cash flow, capital-asset pricing, and expected earnings to establish a composite zone of reasonableness to identify a range of just and reasonable ROEs. FERC then will utilize the transmission utility’s risk relative to other utilities within that zone of reasonableness to assign the transmission utility to one of three quartiles within the zone. FERC would take no further action (i.e.,

dismiss the complaint) if the existing ROE falls within the identified quartile. However, if the ROE falls outside the quartile, FERC would deem the existing ROE presumptively unjust and unreasonable and would determine the replacement ROE. FERC would add a fourth financial model risk premium to the analysis to calculate a ROE based on the average point of central tendency for each of the four financial models. On March 21, 2019, FERC established NOIs to collect industry and stakeholder comments on the revised ROE methodology that is described in the October 16, 2018 decision, and also whether to make changes to FERC's existing policies and practices for awarding transmission rates incentives. FirstEnergy plans to comment and participate in this NOI proceeding and in any subsequent rulemaking or other proceedings.

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 March 31, 2019, outstanding guarantees and other assurances aggregated approximately $1.7 billion, consisting of guarantees on behalf of FES and FENOC ($349 million), parental guarantees on behalf of its consolidated subsidiaries' guarantees ($1 billion), other guarantees ($188 million) and other assurances ($140 million). FirstEnergy has also committed to provide certain additional guarantees to the FES Debtors for retained environmental liabilities of AE Supply related to the Pleasants Power Station and McElroy's Run CCR disposal facility as part of the settlement agreement in connection with the FES Bankruptcy.

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 March 31, 2019, AE Supply has posted no collateral. The Utilities and FET's subsidiaries have posted collateral totaling $3 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 March 31, 2019:

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	—	51	—	51
Surety Bonds (Collateralized Amount)[1]	1	59	246	306
Total Exposure from Contractual Obligations	$ 2	$ 110	$246	$358

(1) 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 for $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 principal balance is $188 million as of March 31, 2019. In addition to FE, Signal Peak, Global Rail, Global Mining Group, LLC and Global Coal Sales Group, LLC, each being a direct or indirect subsidiary of Global Holding, continue to provide their joint and several guaranties of the obligations of Global Holding under the facility.

In connection with the facility, 69.99% of Global Holding's direct and indirect membership interests in Signal Peak, Global Rail and their affiliates along with FEV's and WMB Marketing Ventures, LLC's respective 33-1/3% membership interests in Global Holding, are pledged to the lenders under the current facility as collateral.

ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality, hazardous and solid waste disposal, and other environmental matters. While FirstEnergy's environmental policies and procedures are designed to achieve compliance with applicable environmental laws and regulations, such laws and regulations are subject to periodic review and potential revision by the implementing agencies. FirstEnergy cannot predict the timing or ultimate outcome of any of these reviews or how any future actions taken as a result thereof may materially impact its business, results of operations, cash flows and financial condition.

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 materially impact FirstEnergy's operations, cash flows and financial condition.

In February 2019, the EPA has announced its final decision to retain without changes the NAAQS for SO_2, specifically retaining the 2010 primary (health-based) 1-hour standard of 75 PPB. As of March 31, 2019, the EPA designated 40 areas in 19 states & territories as non-attainment, however, FirstEnergy has no power plants operating in those areas.

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 sought a short-term NOx emission rate limit of 0.125 lb/mmBTU over an averaging period of no more than 24 hours. 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 sought NOx emission rate limits for the 36 EGUs by May 1, 2017. On September 14, 2018, the EPA denied both the States of Delaware and Maryland's petitions under CAA Section 126. In October 2018, Delaware and Maryland appealed the denials of their petitions to the D.C. Circuit. In March 2018, the State of New York filed a CAA Section 126 petition with the EPA alleging that NOx emissions from 9 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 but has not taken any further action. FirstEnergy is unable to predict the outcome of these matters or estimate the loss or range of loss.

Climate Change

There are a number of initiatives to reduce GHG emissions at the state, federal and international level. Certain northeastern states are participating in the RGGI and western states led by California, have implemented programs, primarily cap and trade mechanisms, to control emissions of certain GHGs. Additional policies reducing GHG emissions, such as demand reduction programs, renewable portfolio standards and renewable subsidies have been implemented across the nation.

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. In 2015, FirstEnergy set a goal of reducing company-wide CO_2 emissions by at least 90 percent below 2005 levels by 2045. As of December 31, 2018, FirstEnergy has reduced its CO_2 emissions by approximately 62 percent. In September 2016, the U.S. 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's non-binding obligations to limit global warming to 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.

In December 2009, the EPA released its final “Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act” concluding that concentrations of several key GHGs constitutes an "endangerment" and may be regulated as "air pollutants" under the CAA and mandated measurement and reporting of GHG emissions from certain sources, including electric generating plants. The EPA released its final CPP regulations in August 2015 to reduce CO_2 emissions from existing fossil fuel-fired EGUs and 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 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. To replace the CPP, the EPA proposed the ACE rule on August 21, 2018, which would establish emission guidelines for states to develop plans to address GHG emissions from existing coal-fired power plants. 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.

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. On April 13, 2017, the EPA granted a Petition for Reconsideration and 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.

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. On August 21, 2018, the D.C. Circuit remanded sections of the CCR Rule to the EPA to provide additional safeguards for unlined CCR impoundments that are more protective of human health and the environment.

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 March 31, 2019, 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 $121 million have been accrued through March 31, 2019. Included in the total are accrued liabilities of approximately $85 million for environmental remediation of former MGP 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 March 31, 2019, JCP&L, ME and PN had in total approximately $843 million 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 to 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 FGMUC, 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

Regulated Distribution and Regulated Transmission are FirstEnergy's reportable segments.

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 costs of securing and delivering electric generation from transmission facilities to customers, including the deferral and amortization of certain related costs.

The Regulated Transmission segment provides transmission infrastructure owned and operated by the Transmission Companies 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 the Transmission Companies 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.

The Corporate/Other segment reflects corporate support not charged to FE's subsidiaries, interest expense on FE’s holding company debt and other businesses that do not constitute an operating segment. Reconciling adjustments for the elimination of inter-segment transactions and discontinued operations are shown separately in the following table of Segment Financial Information. As of March 31, 2019, approximately 70 MWs of electric generating capacity, representing AE Supply's OVEC capacity entitlement, was included in continuing operations of the Corporate/Other reportable segment. As of March 31, 2019, Corporate/Other had approximately $7.2 billion of FE holding company debt.

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)				
March 31, 2019					
External revenues	$2,526	$ 352	$ 5	$ —	$ 2,883
Internal revenues	47	4	—	(51)	—
Total revenues	$2,573	$ 356	$ 5	$ (51)	$ 2,883
Depreciation	209	69	2	17	297
Amortization of regulatory assets, net	3	2	—	—	5
Miscellaneous income (expense), net	46	4	11	(7)	54
Interest expense	122	45	93	(7)	253
Income taxes (benefits)	89	31	(27)	—	93
Income (loss) from continuing operations	329	104	(78)	—	355
Total assets	28,992	10,910	588	—	40,490
Total goodwill	5,004	614	—	—	5,618
Property additions	318	231	5	—	554
March 31, 2018					
External revenues	$2,538	$ 319	$ 5	$ —	$ 2,862
Internal revenues	38	4	6	(48)	—
Total revenues	$2,576	$ 323	$ 11	$ (48)	$ 2,862
Depreciation	196	61	2	18	277
Amortization (deferral) of regulatory assets, net	(152)	4	—	—	(148)
Miscellaneous income (expense), net	56	4	16	(9)	67
Interest expense	128	39	90	(9)	248
Income taxes	93	32	108	—	233
Income (loss) from continuing operations	322	99	(240)	—	181
Total assets	27,504	9,681	1,255	355	38,795
Total goodwill	5,004	614	—	—	5,618
Property additions	264	292	11	16	583

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 through its reportable segments, Regulated Distribution and Regulated Transmission.

On March 31, 2018, 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 costs of securing and delivering electric generation from transmission facilities to customers, including the deferral and amortization of certain related costs.

The Regulated Transmission segment provides transmission infrastructure owned and operated by the Transmission Companies 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 the Transmission Companies 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.

The Corporate/Other segment reflects corporate support not charged to FE's subsidiaries, interest expense on FE’s holding company debt and other businesses that do not constitute an operating segment. Additionally, reconciling adjustments for the elimination of inter-segment transactions and discontinued operations are included in Corporate/Other. As of March 31, 2019, approximately 70 MWs of electric generating capacity, representing AE Supply's OVEC capacity entitlement, was included in continuing operations of the Corporate/Other reportable segment. As of March 31, 2019, Corporate/Other had approximately $7.2 billion of FE holding company debt.

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 - through 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 $6.2 to $6.7 billion in forecasted capital investments from 2018 through 2021, Regulated Distribution's rate base growth rate is expected to be approximately 5% from 2018 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 the forward-looking formula rates at ATSI, TrAIL and MAIT. Regulated Transmission has also experienced significant growth as part of its Energizing the Future transmission plan with plans to invest up 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.

As part of the Energizing the Future initiative, a Center for Advanced Technology was opened in Akron, Ohio this month. The 88,000 square feet facility was designed to be a hands-on environment where engineers and technicians can develop and evaluate new technology and grid solutions and simulate a variety of real-world conditions.

FirstEnergy believes there are incremental investment opportunities for its existing transmission infrastructure of over $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. 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. FERC also recently took action to address the impact of the Tax Act on FERC-jurisdictional rates, including transmission and electric wholesale rates. FirstEnergy has 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 equity investment strengthened the Company's balance

sheet, supports the company's transition to a fully regulated utility company and positions FirstEnergy for sustained investment-grade credit metrics. 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. 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 March 31, 2019, 1,406,178 shares of preferred stock have been converted to 51,282,928 shares of common stock at the option of the holders.

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 are not subject to the Chapter 11 process. The voluntary bankruptcy filings by FES and FENOC represented 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 (including the Pleasants Power Station) 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 23, 2018, FirstEnergy and the FES Key Creditor Groups reached an agreement in principle to resolve certain claims by FirstEnergy against the FES Debtors and all claims by the FES Debtors and their creditors against FirstEnergy. On September 26, 2018, the Bankruptcy Court approved a FES Bankruptcy settlement agreement dated August 26, 2018, by and among FirstEnergy,

two groups of key FES creditors (collectively, the FES Key Creditor Groups), the FES Debtors and the UCC. The FES Bankruptcy settlement agreement resolves certain claims by FirstEnergy against the FES Debtors and all claims by the FES Debtors and the FES Key Creditor Groups against FirstEnergy, and 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.
- A nonconsensual release of all claims against FirstEnergy by the FES Debtors' creditors, which was subsequently waived pursuant to the Waiver Agreement, discussed below.
- A $225 million cash payment from FirstEnergy.
- A $628 million aggregate principal amount note issuance by FirstEnergy to the FES Debtors, which may be decreased by the amount, if any, of cash paid by FirstEnergy to the FES Debtors under the Intercompany Income Tax Allocation Agreement for the tax benefits related to the sale or deactivation of certain plants.
- Transfer of the Pleasants Power Station and related assets, including the economic interests therein as of January 1, 2019, and a requirement that FE continue to provide access to the McElroy's Run CCR Impoundment Facility, which is not being transferred. FE will provide certain guarantees for retained environmental liabilities of AE Supply, including the McElroy’s Run CCR Impoundment Facility
- FirstEnergy agrees to waive all pre-petition claims related to shared services and credit for nine months of the FES Debtors' shared service costs beginning as of April 1, 2018 through December 31, 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, subject to a cap, should FES offer a voluntary enhanced retirement package in 2019 and to offer certain other employee benefits (approximately $15 million recognized in the first quarter of 2019).
- FirstEnergy agrees to perform under the Intercompany Tax Allocation Agreement through the FES Debtors’ emergence from bankruptcy, at which time FirstEnergy will waive a 2017 overpayment for NOLs of approximately $71 million, reverse 2018 estimated payments for NOLs of approximately $88 million and pay the FES Debtors for the use of NOLs in an amount no less than $66 million for 2018 (approximately $52 million was paid in 2018, which amount will be finalized after filing the 2018 Federal tax return).

The FES Bankruptcy settlement agreement remains subject to satisfaction of certain conditions, most notably the issuance of a final order by the Bankruptcy Court approving the plan or plans of reorganization for the FES Debtors that are acceptable to FirstEnergy consistent with the requirements of the FES Bankruptcy settlement agreement. There can be no assurance that such conditions will be satisfied or the FES Bankruptcy settlement agreement will be otherwise consummated, and the actual outcome of this matter may differ materially from the terms of the agreement described herein. FirstEnergy will continue to evaluate the impact of any new factors on the settlement and their relative impact on the financial statements.

On April 11, 2019, the Bankruptcy Court entered an order denying the FES Debtors’ disclosure statement approval motion. The Bankruptcy Court concluded that the nonconsensual third-party releases proposed under the plan of reorganization and which were a condition under the FES Bankruptcy settlement agreement for FirstEnergy's benefit, were legally impermissible and rendered the plan unconfirmable. On April 18, 2019, FirstEnergy consented to the waiver of the condition. In return, the FES Debtors agreed to provide FirstEnergy with the same third-party release provided in favor of certain other parties in any plan of reorganization and pay FirstEnergy approximately $60 million in cash to resolve certain outstanding pension and service charges totaling $87 million, which resulted in FirstEnergy recognizing a $27 million pre-tax charge to income in the first quarter of 2019 ($17 million of which was recognized in continuing operations). Further, the FES Debtors agreed to initiate negotiations with the EPA, OEPA, PA DEP and the NRC to obtain those parties' cooperation with the FES Debtors' revised plan of reorganization. FirstEnergy may choose to participate in those negotiations at its option.

In connection with the FES Bankruptcy settlement agreement, FirstEnergy entered into a separation agreement with the FES Debtors to implement the separation of the FES Debtors and their businesses from FirstEnergy. A business

separation committee was established between FirstEnergy and the FES Debtors to review and determine issues that arise in the context of the separation of the FES Debtors' businesses from those of FirstEnergy.

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 will be transferred to FES' creditors under the settlement agreement, and its 67 MW OVEC capacity entitlement.

FINANCIAL OVERVIEW AND RESULTS OF OPERATIONS

(In millions)	For the Three Months Ended March 31,			
	2019	2018	Change	
Revenues	$2,883	$2,862	$21	1 %
Operating expenses	2,254	2,282	(28)	(1)%
Operating income	629	580	49	8 %
Other expenses, net	(181)	(166)	(15)	9 %
Income before income taxes	448	414	34	8 %
Income taxes	93	233	(140)	(60)%
Income from continuing operations	355	181	174	96 %
Discontinued operations, net of tax	(35)	1,188	(1,223)	NM
Net income	$320	$1,369	$(1,049)	(77)%

* 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.

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

Summary of Results of Operations — First Quarter 2019 Compared with First Quarter 2018

Financial results for FirstEnergy's business segments in the first quarter of 2019 and 2018 were as follows:

First Quarter 2019 Financial Results	Regulated Distribution	Regulated Transmission	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)			
Revenues:				
Electric	$2,512	$ 352	$ (31)	$ 2,833
Other	61	4	(15)	50
Total Revenues	2,573	356	(46)	2,883
Operating Expenses:				
Fuel	131	—	—	131
Purchased power	777	—	4	781
Other operating expenses	771	66	(58)	779
Provision for depreciation	209	69	19	297
Amortization of regulatory assets, net	3	2	—	5
General taxes	198	51	12	261
Total Operating Expenses	2,089	188	(23)	2,254
Operating Income (Loss)	484	168	(23)	629
Other Income (Expense):				
Miscellaneous income, net	46	4	4	54
Interest expense	(122)	(45)	(86)	(253)
Capitalized financing costs	10	8	—	18
Total Other Expense	(66)	(33)	(82)	(181)
Income (Loss) Before Income Taxes (Benefits)	418	135	(105)	448
Income taxes (benefits)	89	31	(27)	93
Income (Loss) From Continuing Operations	329	104	(78)	355
Discontinued Operations, net of tax	—	—	(35)	(35)
Net Income (Loss)	$329	$ 104	$ (113)	$ 320

First Quarter 2018 Financial Results	Regulated Distribution	Regulated Transmission	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)			
Revenues:				
Electric	$2,508	$ 319	$ (21)	$ 2,806
Other	68	4	(16)	56
Total Revenues	2,576	323	(37)	2,862
Operating Expenses:				
Fuel	139	—	—	139
Purchased power	819	—	1	820
Other operating expenses	898	54	(12)	940
Provision for depreciation	196	61	20	277
Amortization (deferral) of regulatory assets, net	(152)	4	—	(148)
General taxes	195	47	12	254
Total Operating Expenses	2,095	166	21	2,282
Operating Income (Loss)	481	157	(58)	580
Other Income (Expense):				
Miscellaneous income, net	56	4	7	67
Interest expense	(128)	(39)	(81)	(248)
Capitalized financing costs	6	9	—	15
Total Other Expense	(66)	(26)	(74)	(166)
Income (Loss) Before Income Taxes	415	131	(132)	414
Income taxes	93	32	108	233
Income (Loss) From Continuing Operations	322	99	(240)	181
Discontinued Operations, net of tax	—	—	1,188	1,188
Net Income	$322	$ 99	$ 948	$ 1,369

Changes Between First Quarter 2019 and First Quarter 2018 Financial Results	Regulated Distribution	Regulated Transmission	Corporate/Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)			
Revenues:				
Electric	$4	$ 33	$ (10)	$ 27
Other	(7)	—	1	(6)
Total Revenues	(3)	33	(9)	21
Operating Expenses:				
Fuel	(8)	—	—	(8)
Purchased power	(42)	—	3	(39)
Other operating expenses	(127)	12	(46)	(161)
Provision for depreciation	13	8	(1)	20
Amortization (deferral) of regulatory assets, net	155	(2)	—	153
General taxes	3	4	—	7
Total Operating Expenses	(6)	22	(44)	(28)
Operating Income (Loss)	3	11	35	49
Other Income (Expense):				
Miscellaneous income, net	(10)	—	(3)	(13)
Interest expense	6	(6)	(5)	(5)
Capitalized financing costs	4	(1)	—	3
Total Other Expense	—	(7)	(8)	(15)
Income (Loss) Before Income Taxes (Benefits)	3	4	27	34
Income taxes (benefits)	(4)	(1)	(135)	(140)
Income (Loss) From Continuing Operations	7	5	162	174
Discontinued Operations, net of tax	—	—	(1,223)	(1,223)
Net Income (Loss)	$7	$ 5	$ (1,061)	$ (1,049)

Regulated Distribution — First Quarter 2019 Compared with First Quarter 2018

Regulated Distribution's operating results increased $7 million in the first quarter of 2019, as compared to the same period of 2018, primarily reflecting lower net financing expenses and higher distribution service revenues, partially offset by higher depreciation expense.

Revenues —

The $3 million decrease in total revenues resulted from the following sources:

Revenues by Type of Service	For the Three Months Ended March 31, 2019	2018	Increase (Decrease)
	(In millions)		
Distribution services[1]	$1,348	$1,345	$ 3
Generation sales:			
Retail	1,058	1,040	18
Wholesale	106	123	(17)
Total generation sales	1,164	1,163	1
Other	61	68	(7)
Total Revenues	$2,573	$2,576	$ (3)

[1] Includes $62 million and $64 million of ARP revenues for the three months ended March 31, 2019 and 2018, respectively.

Distribution services revenues increased $3 million, primarily resulting from higher rates associated with the recovery of deferred costs, partially offset by lower weather-related customer usage as described below. Distribution deliveries by customer class are summarized in the following table:

Electric Distribution MWH Deliveries	For the Three Months Ended March 31, 2019	2018	Increase (Decrease)
	(In thousands)		
Residential	15,103	14,999	0.7 %
Commercial	10,381	10,526	(1.4)%
Industrial	13,057	13,075	(0.1)%
Other	140	140	— %
Total Electric Distribution MWH Deliveries	38,681	38,740	(0.2)%

Higher distribution deliveries to residential customers primarily reflect an increase in the number of customers and higher average customer usage, partially offset by state energy efficiency programs and lower weather-related customer usage. Deliveries to commercial customers were lower due to state energy efficiency programs and lower weather-related usage. Deliveries to industrial customers were flat, reflecting higher shale and chemical customer usage being offset by lower steel and automotive customer usage.

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The following table summarizes the price and volume factors contributing to the $1 million increase in generation revenues for the first quarter of 2019 compared to the same period of 2018:

Source of Change in Generation Revenues	Increase (Decrease) (In millions)
Retail:	
Effect of increase in sales volumes	$ 47
Change in prices	(29)
	18
Wholesale:	
Effect of decrease in sales volumes	(16)
Change in prices	(10)
Capacity revenue	9
	(17)
Change in Generation Revenues	$ 1

The increase in retail generation sales volumes was primarily due to decreased customer shopping in New Jersey and Pennsylvania. Total generation provided by alternative suppliers as a percentage of total MWH deliveries decreased to 47% from 51% in New Jersey and to 63% from 65% in Pennsylvania. The decrease in retail generation prices primarily resulted from a lower ENEC rate in West Virginia and rate reductions resulting from the Tax Act.

Wholesale generation revenues decreased $17 million in the first quarter of 2019, as compared to the same period in 2018, primarily due to lower wholesale sales and spot market prices, partially offset by 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 decreased $6 million in the first quarter of 2019, as compared to the same period of 2018, primarily due to the following:

- Fuel costs were $8 million lower in the first quarter of 2019, as compared to the same period in 2018, primarily due to lower generation output.

- Purchased power costs were $42 million lower in the first quarter of 2019, as compared to the same period in 2018, primarily due to lower unit costs resulting from lower auction rates in New Jersey, as well as lower spot market prices in West Virginia.

Source of Change in Purchased Power	Increase (Decrease) (In millions)
Purchases from non-affiliates:	
Change due to decreased unit costs	$ (61)
Change due to volumes	28
	(33)
Purchases from affiliates:	
Change due to decreased unit costs	(2)

Change due to volumes	(18)
	(20)
Capacity expense	11
Decrease in Purchased Power Costs	$ (42)

- Other operating expenses decreased $127 million due to:
  - Decreased storm restoration costs of $112 million, which were deferred for future recovery, resulting in no material impact on current period earnings.
  - Lower energy efficiency program costs of $11 million, which are deferred for future recovery, resulting in no material impact on current period earnings.
  - Lower operating and maintenance expense of $4 million primarily associated with lower employee benefit costs and regulated generation maintenance activities.

- Depreciation expense increased $13 million, primarily due to a higher asset base.

- Amortization expense increased $155 million, primarily due to decreased deferral of storm restoration and energy efficiency program costs.

Other Expense —

Other Expense was flat in the first quarter of 2019, compared to the same period of 2018, primarily due to lower interest expense from debt maturities and refinancings, and higher capitalized financing costs, offset by lower miscellaneous income due to higher pension and OPEB non-service costs.

Income Taxes —

Regulated Distribution’s effective tax rate was 21.3% and 22.4% for the three months ended March 31, 2019 and 2018, respectively.

Regulated Transmission — First Quarter 2019 Compared with First Quarter 2018

Regulated Transmission's operating results increased $5 million in the first quarter of 2019, as compared to the same period of 2018, primarily due to the impact of a higher rate base at ATSI and MAIT, partially offset by a lower rate base at TrAIL.

Revenues —

Total revenues increased $33 million, primarily due to 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 March 31, 2019	2018	Increase (Decrease)
	(In millions)		
ATSI	$175	$159	$ 16
TrAIL	60	62	(2)
MAIT	50	31	19
Other	71	71	—
Total Revenues	$356	$323	$ 33

Operating Expenses —

Total operating expenses increased $22 million, primarily due to higher operating and maintenance expenses as well as higher property taxes and depreciation due to a higher asset base. The majority of the increases were recovered through formula rates at ATSI and MAIT, resulting in no material impact on current period earnings.

Income Taxes —

Regulated Transmission's effective tax rate was 23.0% and 24.4% for the three months ended March 31, 2019 and 2018, respectively.

Corporate / Other — First Quarter 2019 Compared with First Quarter 2018

Financial results from the Corporate/Other operating segment resulted in a $162 million increase in income from continuing operations in the first quarter of 2019, compared to the same period of 2018, primarily due to lower income taxes from the absence of a $126 million charge in the first quarter of 2018 associated with the remeasurement of state deferred taxes in West Virginia when FES and FENOC were removed from the unitary group following their bankruptcy filing on March 31, 2018. Additionally, other operating expenses decreased $46 million primarily due to lower incurred corporate support costs in continuing operations related to FES and FENOC. Although the operations of FES and FENOC for the first quarter of 2018 (prior to deconsolidation on March 31, 2018) are reflected as Discontinued Operations, certain allocated corporate support costs to FES and FENOC continue to be reflected in continued operations.

For the three months ended March 31, 2019 and 2018, FirstEnergy recorded a loss from discontinued operations of $35 million and income from discontinued operations of $1,188 million, respectively. The change in Discontinued operations was primarily due to the absence of a $1.2 billion gain on deconsolidation of FES and FENOC recorded in the first quarter of 2018 following their bankruptcy filing on March 31, 2018.

Regulatory Assets and Liabilities

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, the Utilities and the Transmission Companies net their regulatory assets and liabilities based on federal and state jurisdictions.

The following table provides information about the composition of net regulatory assets and liabilities as of March 31, 2019, and December 31, 2018, and the changes during the three months ended March 31, 2019:

Net Regulatory Assets (Liabilities) by Source	March 31, 2019	December 31, 2018	Change
	(In millions)		
Regulatory transition costs	$12	$ 49	$ (37)
Customer payables for future income taxes	(2,735)	(2,725)	(10)
Nuclear decommissioning and spent fuel disposal costs	(182)	(148)	(34)
Asset removal costs	(791)	(787)	(4)
Deferred transmission costs	160	170	(10)
Deferred generation costs	194	202	(8)
Deferred distribution costs	195	208	(13)
Contract valuations	61	62	(1)
Storm-related costs	563	500	63
Other	51	62	(11)
Net Regulatory Liabilities included on the Consolidated Balance Sheets	$(2,472)	$ (2,407)	$ (65)

The following is a description of the regulatory assets and liabilities described above:

Regulatory transition costs - Primarily relates to JCP&L costs incurred during the transition to a competitive retail market and under-recovered during the period from August 1, 1999 through July 31, 2003; and JCP&L costs associated with basic generation service, capacity and ancillary services, net of all revenues from the sale of the committed supply in the wholesale market. Amounts are amortized through 2021.

Customer payables for future income taxes - Reflects amounts to be recovered or refunded through future rates to pay income taxes that become payable when rate revenue is provided to recover items such as AFUDC-equity and depreciation of property, plant and equipment for which deferred income taxes were not recognized for ratemaking purposes, including amounts attributable to tax rate changes such as tax reform. These amounts are being amortized over the period in which the related deferred tax assets reverse, which is generally over the expected life of the underlying asset.

Nuclear decommissioning and spent fuel disposal costs - Reflects a regulatory liability representing amounts collected from customers and placed in external trusts including income, losses and changes in fair value thereon (as well as accretion of the related ARO) for the future decommissioning of TMI-2.

Asset removal costs - Primarily represents the rates charged to customers that include a provision for the cost of future activities to remove assets, including obligations for which an ARO has been recognized, that are expected to be incurred at the time of retirement.

Deferred transmission costs - Principally represents differences between revenues earned based on actual costs for the formula-rate Transmission Companies and the amounts billed. Amounts are recorded as a regulatory asset or liability and recovered or refunded, respectively, in subsequent periods.

Deferred generation costs - Primarily relates to regulatory assets associated with the securitized recovery of certain electric customer heating discounts, fuel and purchased power regulatory assets at the Ohio Companies (amortized through 2034) as well as the ENEC at MP and PE. 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. The ENEC rate is updated annually.

Deferred distribution costs - Primarily relates to the Ohio Companies' deferral of certain expenses resulting from distribution and reliability related expenditures, including interest, and are amortized through 2036.

Contract valuations - Primarily relates to the recovery of PN above-market NUG costs. Amounts also include the amortization of a purchase accounting adjustment which was recorded in connection with the AE merger representing the fair value of NUG purchased power contracts (amortized over the life of the contracts with various end dates from 2027 through 2036).

Storm-related costs - Relates to the recovery of storm costs, which vary by jurisdiction. Approximately $268 million and $232 million are currently being recovered through rates as of March 31, 2019 and December 31, 2018, respectively.

The following table provides information about the composition of net regulatory assets that do not earn a current return as of March 31, 2019 and December 31, 2018, a majority of which are currently being recovered through rates over varying periods depending on the nature of the deferral and the jurisdiction. Additionally, certain regulatory assets, totaling approximately $109 million as of March 31, 2019, are recorded based on prior precedent or anticipated recovery based on rate making premises without a specific order.

Regulatory Assets by Source Not Earning a Current Return	March 31, 2019	December 31, 2018	Change
	(In millions)		
Regulatory transition costs	$12	$ 10	$ 2
Deferred transmission costs	61	87	(26)
Storm-related costs	429	363	66
Other	38	43	(5)
Regulatory Assets Not Earning a Current Return	$540	$ 503	$ 37

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, and will mandatorily convert in July 2019, subject to limited exceptions but otherwise any remaining preferred shares shall convert in January 2020. Proceeds from the investment were used to reduce holding company debt by $1.45 billion and fund FirstEnergy's pension plan as discussed below, with the remainder used for general corporate purposes. At the option of the shareholders, 494,767 preferred shares were converted into

18,044,018 common shares in January 2019. As of March 31, 2019, 1,406,178 shares of preferred stock have been converted into 51,282,928 shares of common stock at the option of the holders, resulting in 209,822 preferred shares outstanding and yet to be converted.

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 distribution 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 2019 and beyond, FE and its distribution 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 distribution 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.
On February 1, 2019, FirstEnergy made a $500 million voluntary cash contribution to the qualified pension plan. As a result of this contribution, FirstEnergy expects no required contributions through 2021.

FirstEnergy's transmission growth program, Energizing the Future, provides a stable and proven investment platform, while producing important customer benefits. Through the program, $4.4 billion in capital investments were made from 2014 through 2017, and the company plans to invest up to an additional $4.8 billion in the 2018-2021 time frame, which includes a target of $1.2 billion annually through 2021. As noted above, over 80% of these capital investments are recoverable through formula rate mechanisms, reducing regulatory lag in recovering a return on investment, while offering a reasonable rate of return. These investments are expected to continue to improve the performance and condition of the transmission system while increasing automation and communication, adding capacity to the system and improving customer reliability. Beyond 2021, FirstEnergy believes there are incremental investment opportunities for its existing transmission infrastructure of over $20 billion, 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.

In the Regulated Distribution segment, FirstEnergy remains committed to providing customer service-oriented growth opportunities by investing between $6.2 billion and $6.7 billion over 2018 to 2021. Approximately 40% of capital expenditures are recoverable through various rate mechanisms, riders and trackers. Beginning in 2019, expected investments at the Ohio Companies include the pending Ohio Grid Modernization plan which includes installation of approximately 700,000 advanced meters, distribution automation, and integrated 'volt/var' controls. Additionally, the pending JCP&L Reliability Plus infrastructure improvement plan filed with the NJBPU is expected to bring both reduced outages and strengthen the system while preparing for the grid of the future in New Jersey. FirstEnergy continues to explore other opportunities for growth in its Regulated Distribution business, 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 electrification of customers' homes and businesses by providing a full range of products and services.

In alignment with FirstEnergy's strategy to invest in its Regulated Transmission and Regulated Distribution segments as 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. Under the terms of the FES Bankruptcy settlement agreement, FE will release any and all claims against the FES Debtors with respect to the $500 million borrowed under the secured credit facility.

On September 26, 2018, the Bankruptcy Court approved a FES Bankruptcy settlement agreement dated August 26, 2018, by and among FirstEnergy, two groups of key FES creditors (collectively, the FES Key Creditor Groups), the FES Debtors and the UCC. The FES Bankruptcy settlement agreement resolves certain claims by FirstEnergy against the FES Debtors and all claims by the FES Debtors and their creditors against FirstEnergy and would result in the cash payment upon emergence, note issuance and other terms as discussed in the Executive Summary.

The FES Bankruptcy settlement agreement remains subject to satisfaction of certain conditions, most notably the issuance of a final order by the Bankruptcy Court approving the plan or plans of reorganization for the FES Debtors that are acceptable to FirstEnergy consistent with the requirements of the FES Bankruptcy settlement agreement. There can be no assurance that such conditions will be satisfied or the FES Bankruptcy settlement agreement will be otherwise consummated, and the actual outcome of this matter may differ materially from the terms of the agreement described herein. FirstEnergy will continue to evaluate the impact of any new factors on the settlement and their relative impact on the financial statements.

As of March 31, 2019, FirstEnergy's net deficit in working capital (current assets less current liabilities) was due in large part to short-term borrowings of $1.3 billion, currently payable long-term debt, and other current liabilities of approximately $950 million attributable to interest, dividends, customer deposits and anticipated payments under the FES bankruptcy settlement. Currently payable long-term debt as of March 31, 2019, consisted of the following:

Currently Payable Long-Term Debt	(In millions)
Unsecured notes	$ 125
Sinking fund requirements	64
Other notes	17
	$ 206

FirstEnergy believes its cash from operations and available liquidity will be sufficient to meet its working capital needs.

Short-Term Borrowings / Revolving Credit Facilities

FE and the Utilities and FET and certain of its subsidiaries participate in two separate five-year syndicated revolving credit facilities providing for aggregate commitments of $3.5 billion (Facilities), which are available until December 6, 2022. Under the FE Facility, an aggregate amount of $2.5 billion is available to be borrowed, repaid and reborrowed, subject to separate borrowing sublimits for each borrower including FE and its regulated distribution subsidiaries. Under the FET Facility, an aggregate amount of $1.0 billion is available to be borrowed, repaid and reborrowed under a syndicated credit facility, subject to separate borrowing sublimits for each borrower including FE's transmission subsidiaries.

Borrowings under their Facilities may be used 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 $1,300 million and $1,250 million of short-term borrowings as of March 31, 2019 and December 31, 2018, respectively. FirstEnergy's available liquidity from external sources as of April 19, 2019, was as follows:

Borrower(s)	Type	Maturity	Commitment	Available Liquidity
			(In millions)	
FirstEnergy[1]	Revolving	December 2022	$2,500	$ 2,491
FET[2]	Revolving	December 2022	1,000	1,000
		Subtotal	$3,500	$ 3,491
	Cash and cash equivalents		—	201
		Total	$3,500	$ 3,692

[1] FE and the Utilities. Available liquidity includes impact of $9 million of LOCs issued under various terms.
[2] Includes FET and the Transmission Companies.

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 March 31, 2019:

Borrower	FirstEnergy Revolving Credit Facility Sub-Limit	FET Revolving Credit Facility Sub-Limit	Regulatory and Other Short-Term Debt Limitations	
	(In millions)			
FE	$2,500	$ —	$ —	(1)
FET	—	1,000	—	(1)
OE	500	—	500	(2)
CEI	500	—	500	(2)
TE	300	—	300	(2)
JCP&L	500	—	500	(2)
ME	500	—	500	(2)
PN	300	—	300	(2)
WP	200	—	200	(2)
MP	500	—	500	(2)
PE	150	—	150	(2)
ATSI	—	500	500	(2)
Penn	100	—	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, 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 March 31, 2019, the borrowers were in compliance with the applicable debt-to-total-capitalization ratio covenants in each case as defined under the respective Facilities. The minimum interest charge coverage ratio no longer applies following FE's upgrade to an investment grade credit rating.

Term Loans

FE participates in two separate syndicated term loan credit facilities, the first being a $1.25 billion 364-day facility with The Bank of Nova Scotia, as administrative agent, and the lenders identified therein, and the second being a $500

million two-year facility with JPMorgan Chase Bank, N.A., as administrative agent, and the lenders identified therein, respectively. The term loans contain covenants and other terms and conditions substantially similar to those of the FE revolving credit facility described above, including a consolidated debt to total capitalization ratio.

The initial borrowing of $1.75 billion under the new term loans, which took the form of a Eurodollar rate advance, may be converted from time to time, in whole or in part, to alternate base rate advances or other Eurodollar rate advances. Outstanding alternate base rate advances will bear interest at a fluctuating interest rate per annum equal to the sum of an applicable margin for alternate base rate advances determined by reference to FE's reference ratings plus the highest of (i) the administrative agent's publicly-announced "prime rate", (ii) the sum of 1/2 of 1% per annum plus the Federal Funds Rate in effect from time to time and (iii) the rate of interest per annum appearing on a nationally-recognized service such as the Dow Jones Market Service (Telerate) equal to one-month LIBOR on each day plus 1%. Outstanding Eurodollar rate advances will bear interest at LIBOR for interest periods of one week or one, two, three or six months plus an applicable margin determined by reference to FE's reference ratings. Changes in FE's reference ratings would lower or raise its applicable margin depending on whether ratings improved or were lowered, respectively.

FirstEnergy Money Pools

FirstEnergy's utility operating subsidiary companies also have the ability to borrow from each other and FE to meet their short-term working capital requirements. Similar but separate arrangements exist among FirstEnergy's unregulated companies with AE Supply, FE, FET, FEV and certain other unregulated subsidiaries. FESC administers these money pools and tracks surplus funds of FE 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 three months of 2019 was 2.56% per annum for the regulated companies' money pool and 3.21% per annum for the unregulated companies' money pool.

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 April 19, 2019:

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

On March 21, 2019, Moody's upgraded the Senior Unsecured and Issuer ratings of ATSI and MAIT to A3 from Baa1. At the same time, Moody's affirmed the Senior Unsecured and Issuer ratings of their intermediate holding company, FET, at Baa2 as well as TrAIL at A3. The rating outlooks of these companies are stable.

On March 27, 2019, Moody's upgraded JCP&L's Senior Unsecured and Issuer ratings to Baa1 from Baa2, and maintained the positive outlook pending the outcome of the Reliability Plus infrastructure investment program.

On April 17, 2019, Fitch upgraded JCP&L's Senior Unsecured rating to BBB+ from BBB with a positive outlook. Also, on April 17, 2019, Fitch upgraded MP and PE's Senior Secured ratings to A- from BBB+ with a stable outlook and affirmed FE's and all other FE subsidiaries ratings and positive outlooks.

Debt capacity is subject to the consolidated debt-to-total-capitalization limits in the credit facilities previously discussed. As of March 31, 2019, FE and its subsidiaries could issue additional debt of approximately $8.3 billion, or incur a $4.5 billion reduction to equity, and remain within the limitations of the financial covenants required by the FE

Facility.

Changes in Cash Position

As of March 31, 2019, FirstEnergy had $174 million of cash and cash equivalents and approximately $36 million of restricted cash compared to $367 million of cash and cash equivalents and approximately $62 million of restricted cash as of December 31, 2018, 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 distribution and transmission operating subsidiaries. The most significant use of cash from operating activities is buying electricity to serve non-shopping customers 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 category. The following table summarizes the major classes of cash flow items as discontinued operations for the three months ended March 31, 2019 and 2018:

(In millions)	For the Three Months Ended March 31, 2019	2018
CASH FLOWS FROM OPERATING ACTIVITIES:		
Income (loss) from discontinued operations	$(35)	$1,188
Depreciation and amortization, including regulatory assets, net, intangible assets and deferred debt-related costs	—	64
Unrealized gain on derivative transactions	—	(10)

Net cash used for operating activities was $182 million during the first three months of 2019, compared to $880 million the same period of 2018. Key changes were as follows:

- a $750 million decrease in cash contributions to the qualified pension plan;
- higher transmission revenue reflecting a higher base rate and recovery of incremental operating expenses;
- lower storm costs; partially offset by
- the absence of FES' cash from operations in the first quarter of 2019;
- a decline in working capital primarily due to the timing of payments to vendors.

Cash Flows From Financing Activities

In the first three months of 2019, cash provided from financing activities was $593 million, compared to $1,679 million in the same period of 2018. The following table summarizes new equity and debt financing, redemptions, repayments, short-term borrowings and dividends:

Securities Issued or Redeemed / Repaid	For the Three Months Ended March 31, 2019	2018
	(In millions)	
New Issues		
Unsecured notes	$1,400	$—
Preferred stock issuance	$—	$1,616
Common stock issuance	$—	$850
Redemptions / Repayments		
Unsecured notes	$(600)	$—
Term Loan	—	(1,450)
Senior secured notes	(28)	(26)
	$(628)	$(1,476)
Short-term borrowings, net	$50	$900

Preferred stock dividend payments	$(3)	$(21)
Common stock dividend payments	$(201)	$(171)

On January 10, 2019, ME issued $500 million of 4.30% senior notes due 2029. Proceeds from the issuance of senior notes were primarily used to refinance existing indebtedness, including ME's $300 million of 7.70% senior notes due 2019, and borrowings outstanding under the FE regulated utility money pool and the FE Facility, to fund capital expenditures, and for other general corporate purposes.

On February 8, 2019, JCP&L issued $400 million of 4.30% senior notes due 2026. Proceeds from the issuance of the senior notes were primarily used to refinance existing indebtedness, including amounts under the FE regulated utility money pool incurred in connection with the repayment at maturity of JCP&L's $300 million of 7.35% senior notes due 2019 and the funding of storm recovery

and restoration costs and expenses, to fund capital expenditures and working capital requirements and for other general corporate purposes.

On March 28, 2019, FET issued $500 million of 4.55% senior notes due 2049. Proceeds from the issuance of the senior notes were used primarily to support FET's capital structure, to repay short-term borrowings outstanding under the FE unregulated money pool, to finance capital improvements, and for other general corporate purposes, including funding working capital needs and day-to-day operations.

On April 15, 2019, ATSI issued $100 million of 4.38% senior notes due 2031. Proceeds from the issuance of the senior notes were used primarily to repay short-term borrowings, to fund capital expenditures, to fund working capital needs and for other general corporate purposes.

Cash Flows From Investing Activities

Cash used for investing activities in the first three months of 2019 principally represented cash used for property additions. The following table summarizes investing activities for the first three months of 2019 and 2018:

Cash Used for Investing Activities[1]	For the Three Months Ended March 31, 2019	2018	Increase (Decrease)
	(In millions)		
Property Additions:			
Regulated Distribution	$318	$264	$ 54
Regulated Transmission	231	292	(61)
Corporate / Other	5	27	(22)
Proceeds from asset sales	—	(20)	20
Investments	9	22	(13)
Notes receivable from affiliated companies	—	500	(500)
Asset removal costs	65	57	8
Other	2	1	1
	$630	$1,143	$ (513)

[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 three months of 2019 decreased $513 million, compared to the same period of 2018, primarily due to lower property additions and the absence of FES' borrowings from the committed line of credit available under the secured credit facility with FE during the first quarter of 2018.

The decrease in property additions was due to the following:

- a decrease of $61 million at Regulated Transmission due to timing of capital investments associated with its Energizing the Future investment program;
- a decrease of $22 million at Corporate/Other due to lower competitive generation related investments; partially offset by
- an increase of $54 million at Regulated Distribution due to investments in electric system improvements and modernization projects to increase reliability.

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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 March 31, 2019, was approximately $1.7 billion, as summarized below:

Guarantees and Other Assurances	Maximum Exposure (In millions)
FE's Guarantees on Behalf of FES and FENOC	
Energy and Energy-Related Contracts[1]	$ 5
Surety Bonds - FG[2]	200
Deferred compensation arrangements	144
	349
FE's Guarantees on Behalf of its Consolidated Subsidiaries	
AE Supply asset sales[3]	555
Deferred compensation arrangements	425
Fuel related contracts and other	21
	1,001
FE's Guarantees on Behalf of Business Ventures	
Global Holding Facility	188
Other Assurances	
Surety Bonds	131
LOCs[4]	9
	140
Total Guarantees and Other Assurances	$ 1,678

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

(2) FE provides credit support for FG surety bonds for $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 generating plants in December 2017, FE provided the purchaser two limited three-year guarantees totaling $555 million of certain obligations of AE Supply and AGC. In connection with the FES Bankruptcy settlement agreement, FirstEnergy has also committed to provide certain additional guarantees to FG for retained environmental liabilities of AE Supply related to the Pleasants Power Station and the McElroy's Run CCR disposal facility.

(4) Includes $9 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 March 31, 2019, AE Supply has posted no collateral. The Utilities and FET's subsidiaries have posted collateral totaling $3 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 March 31, 2019:

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	—	51	—	51
Surety Bonds (Collateralized Amount)[1]	1	59	246	306
Total Exposure from Contractual Obligations	$ 2	$ 110	$246	$358

(1) 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 for $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 principal balance is $188 million as of March 31, 2019. In addition to FE, Signal Peak, Global Rail, Global Mining Group, LLC and Global Coal Sales Group, LLC, each being a direct or indirect subsidiary of Global Holding, continue to provide their joint and several guaranties of the obligations of Global Holding under the facility.

In connection with the facility, 69.99% of Global Holding's direct and indirect membership interests in Signal Peak, Global Rail and their affiliates along with FEV's and WMB Marketing Ventures, LLC's respective 33-1/3% membership interests in Global Holding, are pledged to the lenders under the current facility as collateral.

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 March 31, 2019, FirstEnergy has a net liability of $42 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 March 31, 2019, the FirstEnergy pension plan assets were allocated approximately as follows: 39% in equity securities, 35% in fixed income securities, 9% in absolute return strategies, 8% in real estate, 2% in private equity, 4% in derivatives and 3% 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. On February 1, 2019, FirstEnergy made a $500 million voluntary cash contribution to the qualified pension plan. As a result of this contribution, FirstEnergy expects no required contributions through 2021. See Note 5, "Pension and Other Postemployment Benefits," of the Notes to Consolidated Financial Statements for additional details on FirstEnergy's pension and OPEB plans. Through March 31, 2019, FirstEnergy's pension plan assets have earned approximately 8.4% as compared to an annual expected return on plan assets of 7.5%.

As of March 31, 2019, FirstEnergy's OPEB plans were invested in fixed income and equity securities. Through March 31, 2019, FirstEnergy's OPEB plans have earned approximately 7.8% 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 March 31, 2019, approximately 54% of the funds were invested in fixed income securities, 45% of the funds were invested in

equity securities and 1% 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 $462 million, $381 million and $8 million for fixed income securities, equity securities and short-term investments, respectively, as of March 31, 2019, excluding $8 million of net receivables, payables and accrued income. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $38 million reduction in fair value as of March 31, 2019. 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 three months ended March 31, 2019, 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 and whenever a plan is determined to qualify for a remeasurement. 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, 2019.

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 requirement that counterparties maintain specified credit ratings) and require other assurances in the form of credit support or collateral in certain circumstance 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 or PE defaults on its obligation, the affected company 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 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. Further, 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.

MARYLAND

PE operates under MDPSC approved base rates that were effective as of March 23, 2019. PE also 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 EmPOWER Maryland program requires each electric utility to file a plan to reduce electric consumption and demand 0.2% per year, 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 2016 starting goal under this requirement was 0.97%. 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. 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.

In 2013, the MDPSC required 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 submitted analysis projected that it would require up to 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 MDPSC's scenarios. The MDPSC conducted a hearing in September 2014, but has not taken further action on this matter.

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 in connection with a 2016 MDPSC 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. PE proposed an electric vehicle charging infrastructure program at a projected total cost of $12 million, to be recovered over a five-year amortization. On January 14, 2019, the MDPSC approved the petition subject to certain reductions in the scope of the program.

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 must track and apply regulatory accounting treatment for the impacts beginning January 1, 2018, and subsequently submitted a report to the MDPSC, estimating that the Tax Act impacts would be approximately $7 million to $8 million annually for PE’s customers. On October 5, 2018, the MDPSC issued an order requiring PE to provide its customers a one-time credit for tax savings through September 30, 2018, which totaled approximately $5 million, and reserved all other Tax Act impacts to be resolved in the pending rate case. In the rate case order issued on March 22, 2019, the MDPSC directed that a further final one-time credit of $3 million be provided to PE's customers within two billing cycles.

On August 24, 2018, PE filed a base rate case with the MDPSC, which it supplemented on October 22, 2018, to update the partially forecasted test year with a full twelve months of actual data. The rate case requested an annual increase in base distribution rates of $19.7 million, plus creation of an EDIS to fund four enhanced service reliability programs. In responding to discovery, PE revised its request for an annual increase in base rates to $17.6 million. The proposed rate increase reflects $7.3 million in annual savings for customers resulting from the recent federal tax law changes. On March 22, 2019, the MDPSC issued a final order that approved a rate increase of $6.2 million, approved three of the four EDIS programs for four years, directed PE to file a new depreciation study within 18 months, and ordered the filing of a new base rate case in four years to correspond to the ending of the approved EDIS programs.

NEW JERSEY

JCP&L operates under NJBPU approved rates that were effective as of January 1, 2017. JCP&L 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. All New Jersey EDCs participate in this competitive BGS procurement process and recover BGS costs directly from customers as a charge separate from base rates.

In December 2017, the NJBPU issued proposed rules to modify its current CTA policy in base rate cases to: (i) calculate savings using a five-year look back from the beginning of the test year; (ii) allocate savings with 75% retained by the company and 25% allocated to rate payers; and (iii) exclude transmission assets of electric distribution companies in the savings calculation, which were published in the NJ Register in the first quarter of 2018. JCP&L filed comments supporting the proposed rulemaking. On January 17, 2019, the NJBPU approved the proposed CTA rules with no changes.

Also in December 2017, 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. On January 23, 2019, the NJBPU granted JCP&L's request to

temporarily suspend the procedural schedule in the matter pending settlement discussions. On April 23, 2019, JCP&L filed a Stipulation of Settlement with the NJBPU on behalf of the JCP&L, Rate Counsel, NJBPU Staff and New Jersey Large Energy Users Coalition, which provides that JCP&L will invest up to approximately $97 million in capital in its electric distribution system beginning on June 1, 2019 and continuing through December 31, 2020. The capital investments will occur in incremental projects that fall under the following three categories: (i) Overhead Circuit Reliability and Resiliency; (ii) Substation Reliability Enhancement; and (iii) Distribution Automation. JCP&L shall seek recovery of the capital investment through an accelerated cost recovery mechanism, provided for in the rules, that includes a revenue adjustment calculation and a process for two rate adjustments. JCP&L expects a NJBPU decision in May 2019.

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.

OHIO

The Ohio Companies currently operate under ESP IV through May 31, 2024. ESP IV includes Rider DMR, which provides for the Ohio Companies to collect $132.5 million annually for three years beginning in 2017, with the possibility of a two-year extension and is 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. On February 1, 2019, the Ohio Companies filed with the PUCO an application requesting a two-year extension of Rider DMR at the same amount and conditions.

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 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. ESP IV also includes: (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 was filed in February 2016, and remains pending as part of the grid modernization settlement described below; (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 Council 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 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. 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. The Ohio Companies then 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, which the PUCO denied. In October 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. The Ohio Companies intervened in the appeal, and additional parties subsequently filed notices of appeal with the Supreme Court of Ohio challenging various PUCO entries on their applications for rehearing. On September 26, 2018, the Supreme Court of Ohio denied a July 30, 2018 joint motion filed by the OCC, the NOAC, and the OMAEG to stay the portions of the PUCO's orders and entries under appeal that authorized Rider DMR. Oral argument on the appeals was held on January 9, 2019.

Under Ohio law, the Ohio Companies are required to implement energy efficiency programs that achieve certain annual energy savings and total peak demand reductions. The Ohio Companies' 2017-2019 plan, as proposed in April 2016, includes 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. In December 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 proposed plans 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. On December 21, 2017, the Ohio Companies filed an application for rehearing challenging the PUCO's modifications, which the PUCO denied on January 10, 2018. On March 12, 2018, the Ohio Companies appealed to the Supreme Court of Ohio challenging the PUCO's imposition of a 4% cost cap. Various other parties also appealed challenging various PUCO entries on their applications for rehearing. Oral argument on the appeals was held on February 20, 2019.

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. On November 9, 2018, the Ohio Companies filed a settlement agreement that provides for the implementation of the first phase of grid modernization plans, including the investment of $516 million over three years to modernize the Ohio Companies' electric distribution system, and for all tax savings associated with the Tax Act, discussed below, to flow back to customers. On January 25, 2019, the Ohio Companies filed a supplemental settlement agreement that keeps intact the provisions of the settlement described above and adds further customer benefits and protections, which broadened support for the settlement. The settlement has broad support, including PUCO Staff, the OCC, representatives of industrial and commercial customers, a low-income advocate, environmental advocates, hospitals, competitive generation suppliers and other parties. The PUCO conducted a hearing and the settlement agreement remains subject to PUCO approval.

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. On October 24, 2018, the PUCO entered an Order in its investigation into the impacts of the Tax Act on Ohio's utilities directing that by January 1, 2019, all Ohio rate-regulated utility companies, unless ordered otherwise, file applications not for an increase in rates to reflect the impact of the Tax Act on each specific utility's current rates. On October 30, 2018, the Ohio Companies filed an application to open a new proceeding for the implementation of matters relating to the impact of the Tax Act. As discussed further above, on November 9, 2018, the Ohio Companies filed a settlement agreement that provides for all tax savings associated with the Tax Act to flow back to customers and for the implementation of the first phase of grid modernization plans. As part of the agreement, the Ohio Companies also filed an application for approval of a rider to return the remaining tax savings to customers following PUCO approval of the settlement. On December 19, 2018, the PUCO upheld its January 10, 2018 ruling that utilities should be required to establish a deferred tax liability, effective January 1, 2018, in response to the Tax Act. On January 25, 2019, the Ohio Companies filed a supplemental settlement agreement that keeps intact the provisions of the settlement described above and adds further customer benefits and protections, which broadened support for the settlement. The PUCO conducted a hearing and the settlement agreement remains subject to PUCO approval.

The Ohio Companies' Rider NMB is designed to recover non-market-based transmission-related costs imposed on or charged to the Ohio Companies by FERC or PJM. On December 14, 2018, the Ohio Companies filed an application for a review of their 2019 Rider NMB, including recovery of future Legacy RTEP costs and previously absorbed Legacy RTEP costs, net of refunds received from PJM. On February 27, 2018, the PUCO issued an Order directing the Ohio Companies to file revised final tariffs recovering Legacy RTEP costs incurred since May 31, 2018, but excluding recovery of approximately $95 million in Legacy RTEP costs incurred prior to May 31, 2018, net of refunds received from PJM. The PUCO solicited comments on whether the Ohio Companies should be permitted to recover the Legacy RTEP charges incurred prior to May 31, 2018. The Ohio Companies, OCC and OMAEG filed comments on March 29, 2019. The Ohio Companies filed reply comments on April 15, 2019.

PENNSYLVANIA

The Pennsylvania Companies operate under rates approved by the PPUC, effective as of January 27, 2017. These rates were adjusted for the net impact of the Tax Act, effective March 15, 2018. The net impact of the Tax Act for the period January 1, 2018 through March 14, 2018 must also be separately tracked for treatment in a future rate proceeding. 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.

The Pennsylvania Companies' DSPs for the June 1, 2019 through May 31, 2023 delivery period were approved by the PPUC in September 2018. Under the 2019-2023 DSPs, the supply will 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 also include modifications to the Pennsylvania Companies' POR programs in order to continue their clawback pilot program as a long-term, permanent program term, 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. The PPUC directed a working group to further discuss the implementation of customer assistance program shopping limitations and appropriate scripting for the Pennsylvania Companies' customer referral programs,

and in November 2018, issued a subsequent order to approve additional customer assistance program shopping parameters and further limit the scope of the working group discussion. On December 21, 2018, the PPUC issued a tentative order proposing a model to incorporate the directed shopping restrictions. Comments on the proposal were filed January 22, 2019. On February 28, 2019, the PPUC issued a final order approving the Pennsylvania Companies' proposal on customer assistance programs shopping limitations and directing script modifications to the Pennsylvania Companies' customer referral programs.

Pursuant to Pennsylvania Act 129 of 2008 and PPUC orders, Pennsylvania EDCs implement energy efficiency and peak demand reduction programs. 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.

Pennsylvania EDCs may establish a DSIC to recover costs of infrastructure improvements and costs related to highway relocation projects with PPUC approval. LTIIPs outlining infrastructure improvement plans for PPUC review and approval must be filed prior to approval of a DSIC. 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. On September 20, 2018, following a periodic review of the LTIIPs as required by regulation once every five years, the PPUC entered an Order concluding that the Pennsylvania Companies have substantially adhered to the schedules and expenditures outlined in their LTIIPs, but that changes to the LTIIPs as designed are necessary to maintain and improve reliability and directed the Pennsylvania Companies to file modified or new LTIIPs. On January 18, 2019, the Pennsylvania Companies filed modifications to their current LTIIPs that would terminate those LTIIPs at the end of 2019, and proposed revised LTIIP spending in 2019 of approximately $45 million by ME, $25 million by

PN, $26 million by Penn and $51 million by WP. The Pennsylvania Companies also committed to making filings later in 2019, which would propose new LTIIPs for the 2020 through 2024 period.

The Pennsylvania Companies' approved DSIC riders for quarterly cost recovery went into effect July 1, 2016, subject to hearings and refund or reallocation among customer classes. In the January 19, 2017 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 April 19, 2018, the PPUC approved the Joint Settlement without modification and reversed the ALJ's previous 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 the Commonwealth Court. Briefing is complete and oral argument is scheduled for June 3, 2019.

WEST VIRGINIA

MP and PE provide electric service to all customers through traditional cost-based, regulated utility ratemaking and operates under rates approved by the WVPSC effective February 2015. 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 August 31, 2018, MP and PE filed a $100.9 million decrease in their ENEC rates proposed to be effective January 1, 2019, which included a $25.6 million annual decrease impact associated with the settlement regarding the impact of the Tax Act on West Virginia rates, as noted below. Additionally, the August 31, 2018 filing included an elimination of the Energy Efficiency Cost Rate Surcharge effective January 1, 2019, equating to an additional $2.1 million decrease. The rate decreases represent an approximate 7.2% annual decrease in rates versus those in effect on August 31, 2018. A unanimous settlement was filed with the WVPSC on November 20, 2018, and a hearing was held on November 27, 2018. An order adopting the settlement in full without modification was issued on January 2, 2019.

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, and record as a regulatory liability, the tax savings resulting from the Tax Act on a monthly basis, effective January 1, 2018. As a result of a WVPSC-approved settlement on August 24, 2018, MP and PE began to flow through to customers $25.6 million in rate reduction beginning September 1, 2018, and to defer to the next base rate case (or a separate proceeding if a base rate case is not filed by August 31, 2020) the amount and classification of the excess ADITs resulting from the Tax Act and the issue of whether MP and PE should be required to credit to customers any of the reduced income tax expense occurring between January 1, 2018 and August 31, 2018.

FERC REGULATORY MATTERS

Under the FPA, FERC regulates rates for interstate wholesale sales, transmission of electric power, accounting and other matters, including construction and operation of hydroelectric projects. With respect to their wholesale services and rates, the Utilities, AE Supply, AGC, and the Transmission Companies are subject to regulation by FERC. FERC regulations require JCP&L, MP, PE, WP and the Transmission Companies to provide open access transmission service at FERC-approved rates, terms and conditions. Transmission facilities of JCP&L, MP, PE, WP and the Transmission Companies are subject to functional control by PJM and transmission service using their transmission facilities is provided by PJM under the PJM Tariff.

FERC regulates the sale of power for resale in interstate commerce in part by granting authority to public utilities to sell wholesale power at market-based rates upon showing that the seller cannot exert market power in generation or transmission or erect barriers to entry into markets. The Utilities and AE Supply each have been authorized by FERC to sell wholesale power in interstate commerce at market-based rates and have a market-based rate tariff on file with FERC, although major wholesale purchases remain subject to regulation by the relevant state commissions.

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, and the Transmission Companies. 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 the facilities that FirstEnergy operates 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.

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. In a subsequent order, FERC affirmed its prior ruling that ATSI must submit the cost/benefit analysis. ATSI is evaluating the cost/benefit approach.

FERC Actions on Tax Act

On March 15, 2018, FERC issued a NOI seeking information regarding whether and how FERC should address possible changes to ADIT and bonus depreciation as a result of the Tax Act. Such possible changes could impact FERC-jurisdictional rates, including transmission rates. On November 15, 2018, FERC issued a NOPR suggesting mechanisms to revise transmission rates to address the Tax Act’s effect on ADIT. Specifically, FERC proposed utilities with transmission formula rates would include mechanisms to (i) deduct any excess ADIT from or add any deficient ADIT to their rate bases; (ii) raise or lower their income tax allowances by any amortized excess or deficient ADIT; and (iii) incorporate a new permanent worksheet into their rates that will annually track information related to excess or deficient ADIT. Utilities with transmission stated rates would determine the amount of excess and deferred income tax caused by the reduced federal corporate income tax rate and return or recover this amount to or from customers. To assist with implementation of the proposed rule, FERC also issued on November 15, 2018, a policy statement providing accounting and ratemaking guidance for treatment of ADIT for all FERC-jurisdictional public utilities. The policy statement also addresses the accounting and ratemaking treatment of ADIT following the sale or retirement of an asset after December 31, 2017. FESC, on behalf of its affiliated transmission owners, supported comments submitted by Edison Electric Institute requesting additional clarification on the ratemaking and accounting treatment for ADIT in formula and stated transmission rates. FERC's final rule remains pending.

Transmission ROE Methodology

In June 2014, FERC issued Opinion No. 531 revising its approach for calculating the discounted cash flow element of FERC’s ROE methodology and announcing the potential for a qualitative adjustment to the ROE methodology results. Parties appealed to the D.C. Circuit, and on April 14, 2017, that court issued a decision vacating FERC’s order and remanding the matter to FERC for further review. On October 16, 2018, FERC issued its order on remand, in which it proposed a revised ROE methodology. Specifically, in complaint proceedings alleging that an existing ROE is not just and reasonable, FERC proposes to rely on three financial models-discounted cash flow, capital-asset pricing, and expected earnings to establish a composite zone of reasonableness to identify a range of just and reasonable ROEs. FERC then will utilize the transmission utility’s risk relative to other utilities within that zone of reasonableness to assign the transmission utility to one of three quartiles within the zone. FERC would take no further action (i.e., dismiss the complaint) if the existing ROE falls within the identified quartile. However, if the ROE falls outside the quartile, FERC would deem the existing ROE presumptively unjust and unreasonable and would determine the replacement ROE. FERC would add a fourth financial model risk premium to the analysis to calculate a ROE based

on the average point of central tendency for each of the four financial models. On March 21, 2019, FERC established NOIs to collect industry and stakeholder comments on the revised ROE methodology that is described in the October 16, 2018 decision, and also whether to make changes to FERC's existing policies and practices for awarding transmission rates incentives. FirstEnergy plans to comment and participate in this NOI proceeding and in any subsequent rulemaking or other proceedings.

ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality, hazardous and solid waste disposal, and other environmental matters. While FirstEnergy's environmental policies and procedures are designed to achieve compliance with applicable environmental laws and regulations, such laws and regulations are subject to periodic review and potential revision by the implementing agencies. FirstEnergy cannot predict the timing or ultimate outcome of any of these reviews or how any future actions taken as a result thereof may materially impact its business, results of operations, cash flows and financial condition.

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 materially impact FirstEnergy's operations, cash flows and financial condition.

In February 2019, the EPA has announced its final decision to retain without changes the NAAQS for SO_2, specifically retaining the 2010 primary (health-based) 1-hour standard of 75 PPB. As of March 31, 2019, the EPA designated 40 areas in 19 states & territories as non-attainment, however, FirstEnergy has no power plants operating in those areas.

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 sought a short-term NOx emission rate limit of 0.125 lb/mmBTU over an averaging period of no more than 24 hours. 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 sought NOx emission rate limits for the 36 EGUs by May 1, 2017. On September 14, 2018, the EPA denied both the States of Delaware and Maryland's petitions under CAA Section 126. In October 2018, Delaware and Maryland appealed the denials of their petitions to the D.C. Circuit. In March 2018, the State of New York filed a CAA Section 126 petition with the EPA alleging that NOx emissions from 9 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 but has not taken any further action. FirstEnergy is unable to predict the outcome of these matters or estimate the loss or range of loss.

Climate Change

There are a number of initiatives to reduce GHG emissions at the state, federal and international level. Certain northeastern states are participating in the RGGI and western states led by California, have implemented programs, primarily cap and trade mechanisms, to control emissions of certain GHGs. Additional policies reducing GHG emissions, such as demand reduction programs, renewable portfolio standards and renewable subsidies have been implemented across the nation.

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. In 2015, FirstEnergy set a goal of reducing company-wide CO_2 emissions by at least 90 percent below 2005 levels by 2045. As of December 31,

2018, FirstEnergy has reduced its CO_2 emissions by approximately 62 percent. In September 2016, the U.S. 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's non-binding obligations to limit global warming to 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.

In December 2009, the EPA released its final "Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act" concluding that concentrations of several key GHGs constitutes an "endangerment" and may be regulated as "air pollutants" under the CAA and mandated measurement and reporting of GHG emissions from certain sources, including electric generating plants. The EPA released its final CPP regulations in August 2015 to reduce CO_2 emissions from existing fossil fuel-fired EGUs and 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 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. To replace the CPP, the EPA proposed the ACE rule on August 21, 2018, which would establish emission guidelines for states to develop plans to address GHG emissions from existing coal-fired power plants. 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.

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. On April 13, 2017, the EPA granted a Petition for Reconsideration and 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.

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. On August 21, 2018, the D.C. Circuit remanded sections of the CCR Rule to the EPA to provide additional safeguards for unlined CCR impoundments that are more protective of human health and the environment.

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 March 31, 2019, 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 $121 million have been accrued through March 31, 2019. Included in the total are accrued liabilities of approximately $85 million for environmental remediation of former MGP 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 March 31, 2019, JCP&L, ME and PN had in total approximately $843 million 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 to 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 FGMUC, 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 2016-02, "Leases (Topic 842)" (Issued February 2016 and subsequently updated to address implementation questions): The new guidance requires 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, as well as new qualitative and quantitative disclosures. FirstEnergy implemented a third-party software tool that assisted with the initial adoption and will assist with ongoing compliance. FirstEnergy chose to apply the requirements of the standard in the period of adoption (January 1, 2019) with no restatement of prior periods. Upon adoption, on January 1, 2019, FirstEnergy increased assets and liabilities by $186 million, with no impact to results of operations or cash flows. See Note 8, "Leases," for additional information on FirstEnergy's leases.

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 based upon the current expectation that such new standards will not significantly impact FirstEnergy's financial reporting.

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

ASU 2018-15, "Intangibles-Goodwill and Other-Internal-Use Software (Subtopic 350-40): Customer’s Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract" (Issued August 2018): ASU 2018-15 requires implementation costs incurred by customers in cloud computing arrangements to be deferred and recognized over the term of the arrangement, if those costs would be capitalized by the customers in a software licensing arrangement. The guidance will be effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019, with early adoption permitted.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See “FirstEnergy 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 March 31, 2019, 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

During the quarter ended March 31, 2019, there were no material changes to the risk factors included in our Annual Report on Form 10-K for the year ended December 31, 2018.

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

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5. OTHER INFORMATION

FES Bankruptcy Settlement Agreement Waiver

On August 26, 2018, FirstEnergy, the FES Key Creditor Groups, the FES Debtors and the UCC entered in the FES Bankruptcy settlement agreement, which was approved by the Bankruptcy Court on September 26, 2018.

On April 11, 2019, the Bankruptcy Court entered an order denying the FES Debtors’ disclosure statement approval motion. The Bankruptcy Court concluded that the nonconsensual third-party releases proposed under the plan of reorganization, which were a condition under the FES Bankruptcy settlement agreement for FirstEnergy's benefit,

were legally impermissible and rendered the plan unconfirmable. On April 18, 2019, FirstEnergy and the FES Debtors entered into a consent and Waiver to the Settlement Agreement (the Waiver Agreement), by which FirstEnergy consented to the waiver of the condition. In return, the FES Debtors agreed to provide FirstEnergy with the same consensual third-party releases provided in favor of certain other parties in any plan of reorganization and pay FirstEnergy approximately $60 million in cash to resolve certain outstanding pension and service charges. In addition, pursuant to the Waiver Agreement, FirstEnergy and FES agreed to clarifications regarding the calculation of certain go-forward pension service costs that will be charged to the Debtors prior to the Plan Effective Date, and certain postpetition retiree health and welfare plan service costs. Further, the FES Debtors agreed to initiate negotiations with the EPA, OEPA, PA DEP and NRC to obtain those parties' cooperation with the FES Debtors' revised plan of reorganization. FirstEnergy may choose to participate in those negotiations at its option.

The foregoing summary is qualified in its entirety by reference to the Waiver Agreement, which is filed as Exhibit 10.1 to this Quarterly Report on Form 10-Q and which is incorporated by reference herein.

ITEM 6. EXHIBITS

	Exhibit Number	Description
(A)	10.1	Consent and Waiver to the Settlement Agreement, dated April 18, 2019, by and among the Debtors and the FE Non-Debtor Parties.
(A) (B)	10.2	Form of 2019-2021 Cash-Based Performance-Adjusted Restricted Stock Unit Award Agreement.
(A) (B)	10.3	Form of 2019-2021 Stock-Based Performance-Adjusted Restricted Stock Unit Award Agreement.
(A) (B)	10.4	Form of 2019 Restricted Stock Award Agreement.
(B)	10.5	Amendment No. 3 to FirstEnergy Corp. Deferred Compensation Plan for Outside Directors, dated January 14, 2019 and effective as of April 1, 2018 (incorporated by reference to FE's Form 10-K filed February 19, 2019, Exhibit 10-7, File No.333-21011).
(B)	10.6	Amendment No. 2 to FirstEnergy Corp. Supplemental Executive Retirement Plan, dated January 14, 2019 and effective as of April 1, 2018 (incorporated by reference to FE's Form 10-K filed February 19, 2019, Exhibit 10-10, File No. 333-21011).
(B)	10.7	Amendment No. 1 to FirstEnergy Corp. Amended and Restated Executive Deferred Compensation Plan, dated January 14, 2019 and effective as of April 1, 2018 (incorporated by reference to FE's Form 10-K filed February 19, 2019, Exhibit 10-23, File No. 333-21011).
(A)	31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-14(a).
(A)	31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-14(a).
(A)	32	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350.
	101	The following materials from the Quarterly Report on Form 10-Q of FirstEnergy Corp. for the period ended March 31, 2019, 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.

April 23, 2019

FIRSTENERGY CORP.
Registrant

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