Fourth Quarter 2016 FactBook

February 21, 2017

FirstEnergy

FIRSTENERGY

FactBook

Published February 21, 2017

Forward-Looking Statements

This FactBook includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements include declarations regarding management's intents, beliefs and current expectations. These statements typically contain, but are not limited to, the terms "anticipate," "potential," "expect," "forecast," "target," "will," "intend," "believe," "project," "estimate," "plan" and similar words. Forward-looking statements involve estimates, assumptions, known and unknown risks, uncertainties and other factors that may cause actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements, which may include the following: the ability to experience growth in the Regulated Distribution and Regulated Transmission segments; the accomplishment of our regulatory and operational goals in connection with our transmission investment plan, including, but not limited to, our planned forward-looking formula rates and the effectiveness of our strategy to reflect a more regulated business profile; changes in assumptions regarding economic conditions within our territories, assessment of the reliability of our transmission system, or the availability of capital or other resources supporting identified transmission investment opportunities; the ability to accomplish or realize anticipated benefits from strategic and financial goals, including, but not limited to, the ability to continue to reduce costs and to successfully execute our financial plans designed to improve our credit metrics and strengthen our balance sheet through, among other actions, our cash flow improvement plan and other proposed capital raising initiatives; the risks and uncertainties associated with the lack of viable alternative strategies regarding the Competitive Energy Services (CES) segment, thereby causing FirstEnergy Solutions Corp. (FES), and possibly FirstEnergy Nuclear Operating Company (FENOC), to restructure its debt and other financial obligations with its creditors or seek protection under United States bankruptcy laws and the losses, liabilities and claims arising from such bankruptcy proceeding, including any obligations at FirstEnergy; the risks and uncertainties at the CES segment, including FES and its subsidiaries and FENOC, related to continued depressed wholesale energy and capacity markets, and the viability and/or success of strategic business alternatives, such as potential CES generating unit asset sales, the potential conversion of the remaining generation fleet from competitive operations to a regulated or regulated-like construct or the potential need to deactivate additional generating units; the substantial uncertainty as to FES' ability to continue as a going concern and substantial risk that it may be necessary for FES, and possibly FENOC, to seek protection under United States bankruptcy laws; the risks and uncertainties associated with litigation, arbitration, mediation and like proceedings, including, but not limited to, any such proceedings related to vendor commitments, such as long-term fuel and transportation agreements; the uncertainties associated with the deactivation of older regulated and competitive units, including the impact on vendor commitments, such as long-term fuel and transportation agreements, and as it relates to the reliability of the transmission grid, the timing thereof; the impact of other future changes to the operational status or availability of our generating units and any capacity performance charges associated with unit unavailability; changing energy, capacity and commodity market prices including, but not limited to, coal, natural gas and oil prices, and their availability and impact on margins; costs being higher than anticipated and the success of our policies to control costs and to mitigate low energy, capacity and market prices; replacement power costs being higher than anticipated or not fully hedged; our ability to improve electric commodity margins and the impact of, among other factors, the increased cost of fuel and fuel transportation on such margins; the speed and nature of increased competition in the electric utility industry, in general, and the retail sales market in particular; the uncertainty of the timing and amounts of the capital expenditures that may arise in connection with any litigation, including New Source Review litigation, or potential regulatory initiatives or rulemakings (including that such initiatives or rulemakings could result in our decision to deactivate or idle certain generating units); changes in customers' demand for power, including, but not limited to, changes resulting from the implementation of state and federal energy efficiency and peak demand reduction mandates; economic or weather conditions affecting future sales and margins such as a polar vortex or other significant weather events, and all associated regulatory events or actions; changes in national and regional economic conditions affecting us, our subsidiaries and/or our major industrial and commercial customers, and other counterparties with which we do business, including fuel suppliers; the impact of labor disruptions by our unionized workforce; the risks associated with cyber-attacks and other disruptions to our information technology system that may compromise our generation, transmission and/or distribution services and data security breaches of sensitive data, intellectual property and proprietary or personally identifiable information regarding our business, employees, shareholders, customers, suppliers, business partners and other individuals in our data centers and on our networks; the impact of the regulatory process and resulting outcomes on the matters at the federal level and in the various states in which we do business including, but not limited to, matters related to rates and the Ohio Distribution Modernization Rider; the impact of the federal regulatory process on Federal Energy Regulatory Commission (FERC) regulated entities and transactions, in particular FERC regulation of wholesale energy and capacity markets, including PJM Interconnection, L.L.C. (PJM) markets and FERC-jurisdictional wholesale transactions; FERC regulation of cost-of-service rates; and FERC's compliance and enforcement activity, including compliance and enforcement activity related to North American Electric Reliability Corporation's mandatory reliability standards; the uncertainties of various cost recovery and cost allocation issues resulting from American Transmission Systems, Incorporated's realignment into PJM; the ability to comply with applicable state and federal reliability standards and energy efficiency and peak demand reduction mandates; other legislative and regulatory changes, and revised environmental requirements, including, but not limited to, the effects of the United States Environmental Protection Agency's Clean Power Plan, Coal Combustion Residuals regulations, Cross-State Air Pollution Rule and Mercury and Air Toxics Standards programs, including our estimated costs of compliance, Clean Water Act (CWA) waste water effluent limitations for power plants, and CWA 316(b) water intake regulation; adverse regulatory or legal decisions and outcomes with respect to our nuclear operations (including, but not limited to, the revocation or non-renewal of necessary licenses, approvals or operating permits by the Nuclear Regulatory Commission or as a result of the incident at Japan's Fukushima Daiichi Nuclear Plant); issues arising from the indications of cracking in the shield building at Davis-Besse; changing market conditions that could affect the measurement of certain liabilities and the value of assets held in our Nuclear Decommissioning Trusts, pension trusts and other trust funds, and cause us and/or our subsidiaries to make additional contributions sooner, or in amounts that are larger than currently anticipated; the impact of changes to significant accounting policies; the impact of any changes in tax laws or regulations or adverse tax audit results or rulings; the ability to access the public securities and other capital and credit markets in accordance with our financial plans, the cost of such capital and overall condition of the capital and credit markets affecting us and our subsidiaries; further actions that may be taken by credit rating agencies that could negatively affect us and/or our subsidiaries' access to financing, increase the costs thereof, increase requirements to post additional collateral to support, or accelerate payments under outstanding commodity positions, letters of credit and other financial guarantees, and the impact of these events on the financial condition and liquidity of FirstEnergy and/or its subsidiaries, specifically the subsidiaries within the CES segment; issues concerning the stability of domestic and foreign financial institutions and counterparties with which we do business; and the risks and other factors discussed from time to time in our United States Securities and Exchange Commission (SEC) filings, and other similar factors. Dividends declared from time to time on FirstEnergy Corp.'s common stock during any period may in the aggregate vary from prior periods due to circumstances considered by FirstEnergy Corp.'s Board of Directors at the time of the actual declarations. A security rating is not a recommendation to buy or hold securities and is subject to revision or withdrawal at any time by the assigning rating agency. Each rating should be evaluated independently of any other rating. The foregoing factors should not be construed as exhaustive and should be read in conjunction with the other cautionary statements and risks that are included in our 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. 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 Corp.'s business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. The registrants expressly disclaim any current intention to update, except as required by law, any forward-looking statements contained herein as a result of new information, future events or otherwise.

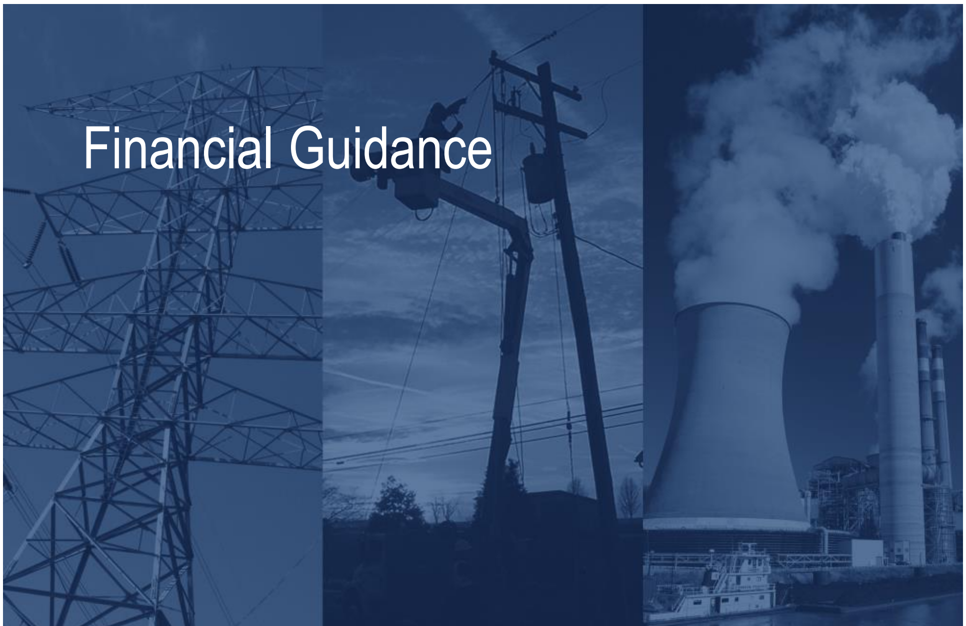
Non-GAAP Financial Matters

This FactBook contains references to non-GAAP financial measures including, among others, Operating earnings, CES Adjusted EBITDA, Funds from Operations, and Free Cash Flow. In addition, Basic EPS-Operating, calculated on a segment basis, is also a non-GAAP financial measure. Generally, a non-GAAP financial measure is a numerical measure of a company's historical or future financial performance, financial position, or cash flows that either excludes or includes amounts that are not normally excluded or included in the most directly comparable measure calculated and presented in accordance with accounting principles generally accepted in the United States (GAAP). Operating earnings are not calculated in accordance with GAAP because they exclude the impact of "special items". Special items represent charges incurred or benefits realized that management believes are not indicative of, or may obscure trends useful in evaluating the company's ongoing core activities and results of operations or otherwise warrant separate classification. Special items are not necessarily non-recurring. Basic EPS-Operating for each segment is calculated by dividing segment Operating earnings (losses), which exclude special items as discussed above, by the basic weighted average shares outstanding for the period. Management uses non-GAAP financial measures such as Operating earnings, CES Adjusted EBITDA, Funds from Operations, and Free Cash Flow to evaluate the company's performance and manage its operations and frequently references these non-GAAP financial measures in its decision-making, using them to facilitate historical and ongoing performance comparisons. Additionally, management uses Basic EPS-Operating by segment to further evaluate FirstEnergy's performance by segment and references this non-GAAP financial measure in its decision-making. Management believes that the non-GAAP financial measures of Operating earnings and Basic EPS-Operating by segment provide consistent and comparable measures of performance of its businesses on an ongoing basis using the same measures management uses in forecasting, budgeting, long-term planning, and setting compensation. Management also believes that such measures are useful to shareholders and other interested parties to understand performance trends and evaluate the company against its peer group by presenting period-over-period operating results without the effect of certain charges or benefits that may not be consistent or comparable across periods or across the company's peer group. All of these non-GAAP financial measures are intended to complement, and are not considered as alternatives to, the most directly comparable GAAP financial measures. Also, the non-GAAP financial measures may not be comparable to similarly titled measures used by other entities.

Pursuant to the requirements of Regulation G, FirstEnergy has provided quantitative reconciliations within this presentation of the non-GAAP financial measures to the most directly comparable GAAP financial measures. Refer to slides 12-16 of the Guidance Materials.

Guidance Materials

Unlocking Value for Investors



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Unlocking Value for Investors

2016A – 2017F Earnings Guidance

FE Consolidated Summary

	Basic EPS [1]		Special Items [2]		Basic EPS – Operating (Non-GAAP)	
	2016A	**2017F**	**2016A**	**2017F**	**2016A**	**2017F**
Regulated Distribution	$1.53	$2.20 - $2.30	$0.28	$0.04	$1.81	$2.24 - $2.34
Regulated Transmission	$0.78	$0.81 - $0.85	-	-	$0.78	$0.81 - $0.85
Competitive Energy Services	($16.23)	$0.01 - $0.13	$16.83	$0.19	$0.60	$0.20 - $0.32
Corporate / Other	($0.57)	($0.55) - ($0.51)	$0.01	-	($0.56)	($0.55) - ($0.51)
FE Consolidated	**($14.49)**	**$2.47 - $2.77**	**$17.12**	**$0.23**	**$2.63**	**$2.70 - $3.00**

[1] Before excluding special items

[2] See slides 12-16 for additional details regarding special items

Per share amounts for the special items and earnings drivers above and throughout these materials are based on the after-tax effect of each item divided by the weighted average basic shares outstanding and assumes up to $600 million of additional equity in 2017.

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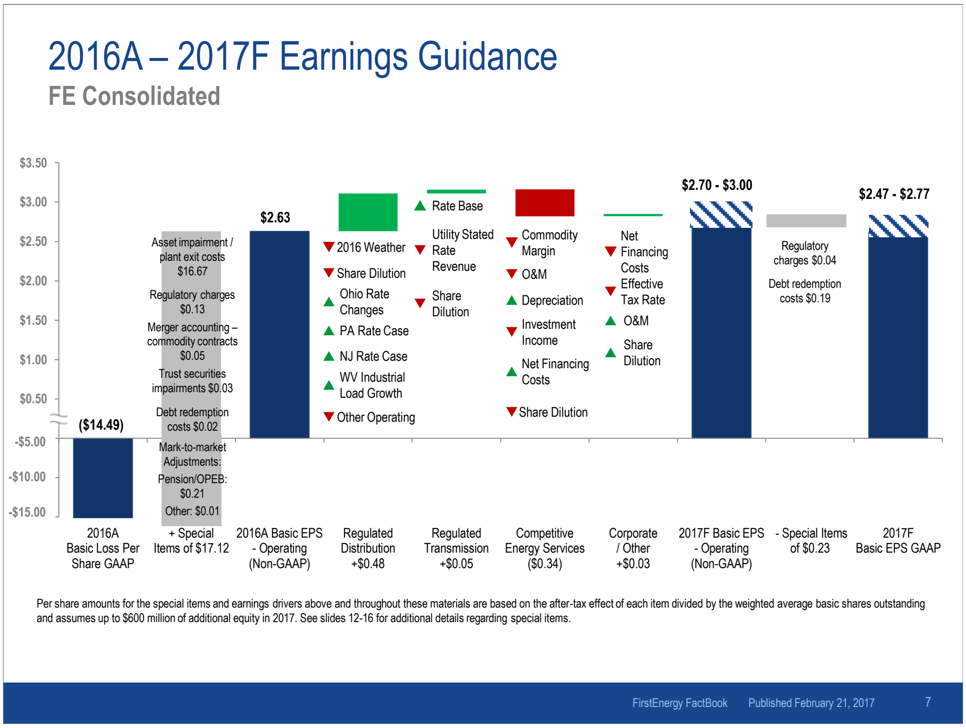
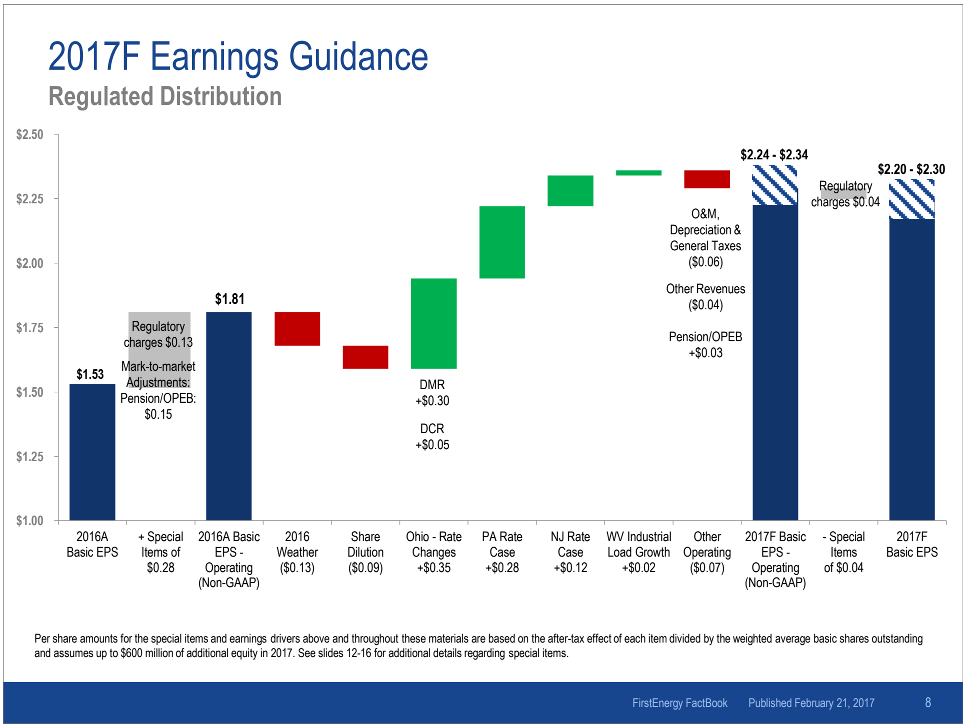
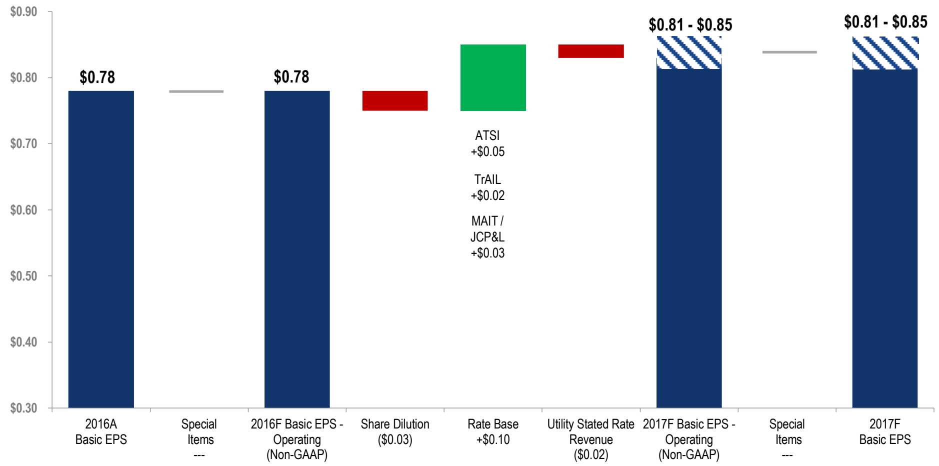




2017F Earnings Guidance

Regulated Transmission



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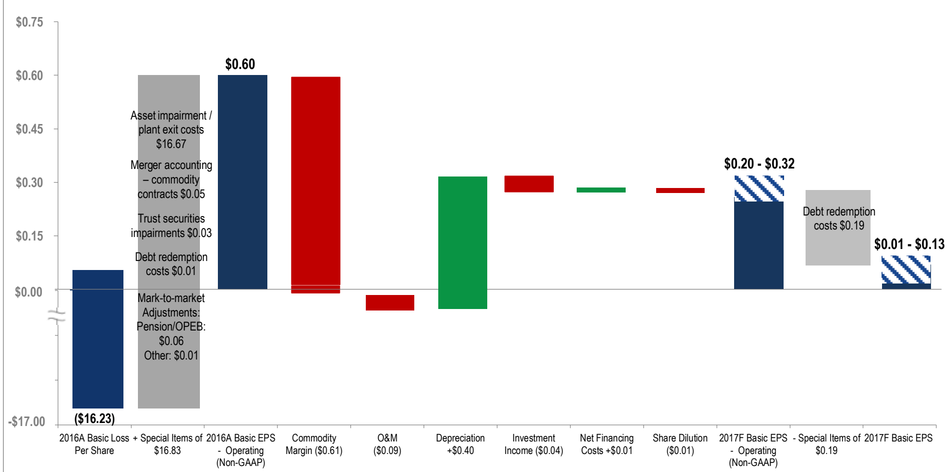
2017F Earnings Guidance

Competitive Energy Services



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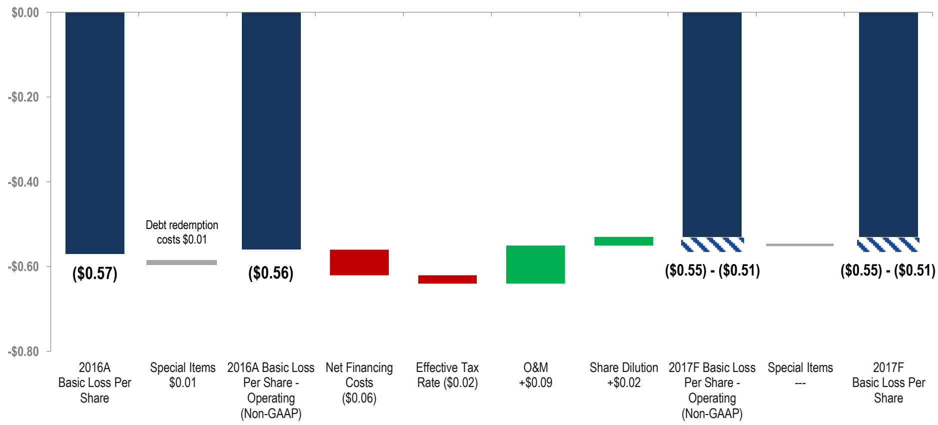
2017F Earnings Guidance

Corporate / Other



Per share amounts for the special items and earnings drivers above and throughout these materials are based on the after-tax effect of each item divided by the weighted average basic shares outstanding and assumes up to $600 million of additional equity in 2017. See slides 12-16 for additional details regarding special items.

2016A GAAP to Operating (Non-GAAP) Earnings[1] Reconciliation

	2016 Actual					
(In $M, except per share amounts)	FirstEnergy Consolidated	Regulated Distribution	Regulated Transmission	Regulated Distribution and Transmission Subtotal	Competitive Energy Services	Corporate/ Other
Net Income (Loss) – GAAP	($6,177)	$651	$331	$982	($6,919)	($240)
Basic EPS (Loss Per Share)	($14.49)	$1.53	$0.78	$2.31	($16.23)	($0.57)
Excluding Special Items						
Regulatory Charges	0.13	0.13	-	0.13	-	-
Trust Securities Impairments	0.03	-	-	-	0.03	-
Merger Accounting – Commodity Contracts	0.05	-	-	-	0.05	-
Asset Impairment/Plant Exit Costs	16.67	-	-	-	16.67	-
Debt redemption costs	0.02	-	-	-	0.01	0.01
Mark-to-market Adjustments						
Pension/OPEB actuarial assumptions	0.21	0.15	-	0.15	0.06	-
Other	0.01	-	-	-	0.01	-
Total Special Items	$17.12	$0.28	-	$0.28	$16.83	$0.01
Basic EPS – Operating (Non-GAAP)	$2.63	$1.81	$0.78	$2.59	$0.60	($0.56)

[1] Operating earnings exclude special items as described in the reconciliation table above and is a non-GAAP financial measure.

Per share amounts for the special items and earnings drivers above and throughout these materials are based on the after-tax effect of each item divided by the weighted average basic shares outstanding for the period of 426M. The current and deferred income tax effect was calculated by applying the subsidiaries' statutory tax rate to the pre-tax amount with the exception of Asset impairment/Plant exit costs that included an impairment of goodwill, of which $433 million of the $800 million pre-tax impairment was non-deductible for tax purposes, and valuation allowances against state and local NOL carryforwards of $159 million. With the exception of these items included in Asset impairment/Plant exit costs, the income tax rates range from 35% to 41%.

2016A Special Items

(In $M, except per share amounts)

	2016 Actual								
	FirstEnergy Consolidated [1]			Regulated Distribution			Competitive Energy Services		
	Pre-Tax	After-Tax	EPS	Pre-Tax	After-Tax	EPS	Pre-Tax	After-Tax	EPS
Regulatory Charges	$87	$56	$0.13	$87	$56	$0.13	$ -	$ -	$ -
Trust Securities Impairments	21	13	0.03	2	1	-	19	12	0.03
Merger Accounting – Commodity Contracts	32	21	0.05	-	-	-	32	21	0.05
Asset Impairment/Plant Exit Costs	10,721	7,105	16.67	-	-	-	10,721	7,105	16.67
Mark-to-market Adjustments									
Pension/OPEB actuarial assumptions	147	90	0.21	101	62	0.15	45	28	0.06
Other	9	5	0.01	-	-	-	9	5	0.01
Debt Redemptions Costs	11	7	0.02	2	1	-	7	4	0.01
Total Special Items	**$11,028**	**$7,297**	**$17.12**	**$192**	**$120**	**$0.28**	**$10,833**	**$7,175**	**$16.83**

Per share amounts for the special items and earnings drivers above and throughout these materials are based on the after-tax effect of each item divided by the weighted average basic shares outstanding for the period of 426M. The current and deferred income tax effect was calculated by applying the subsidiaries' statutory tax rate to the pre-tax amount with the exception of Asset impairment/Plant exit costs that included an impairment of goodwill, of which $433 million of the $800 million pre-tax impairment was non-deductible for tax purposes, and valuation allowances against state and local NOL carryforwards of $159 million. With the exception of these items included in Asset impairment/Plant exit costs, the income tax rates range from 35% to 41%.

[1] Includes $2 million pre-tax charge associated with Debt Redemption Costs at Corporate/Other. Also, includes $1 million pre-tax charges associated with Pension/OPEB mark-to-market adjustment at Regulated Transmission.

2017F GAAP to Operating (Non-GAAP) Earnings[1] Reconciliation

	2017F				
(In $M, except per share amounts)	FirstEnergy Consolidated	Regulated Distribution	Regulated Transmission	Competitive Energy Services	Corporate/ Other
Net Income (Loss) – GAAP	$1,100 - $1,235	$980 - $1,025	$360 - $380	$5 - $55	($245) - ($225)
Basic EPS (Loss Per Share) (average shares outstanding 445M)	$2.47 - $2.77	$2.20 - $2.30	$0.81 - $0.85	$0.01 - $0.13	($0.55) - ($0.51)
Excluding Special Items:					
Regulatory Charges	0.04	0.04	-	-	-
Debt Redemption Costs	0.19	-	-	0.19	-
Total Special Items	$0.23	$0.04	-	$0.19	-
Basic EPS – Operating (Non-GAAP) (average shares outstanding 445M)	$2.70 - $3.00	$2.24 - $2.34	$0.81 - $0.85	$0.20 - $0.32	($0.55) - ($0.51)

[1] Operating earnings exclude special items as described in the reconciliation table above and is a non-GAAP financial measure.

Per share amounts for the special items and earnings drivers above and throughout these materials are based on the after-tax effect of each item divided by the weighted average basic shares outstanding and assumes up to $600 million of additional equity in 2017. The current and deferred income tax effect was calculated by applying the subsidiaries' statutory tax rate to the pre-tax amount. The income tax rates range from 37% to 42%.

2017F Special Items

(In $M, except per share amounts)

	2017F								
	FirstEnergy Consolidated			Regulated Distribution			Competitive Energy Services		
	Pre-Tax	After-Tax	EPS	Pre-Tax	After-Tax	EPS	Pre-Tax	After-Tax	EPS
Regulatory Charges	$26	$15	$0.04	$26	$15	$0.04	-	-	-
Debt Redemption	135	85	0.19	-	-	-	135	85	0.19
Total Special Items	**$161**	**$100**	**$0.23**	**$26**	**$15**	**$0.04**	**$135**	**$85**	**$0.19**

Per share amounts for the special items and earnings drivers above and throughout these materials are based on the after-tax effect of each item divided by the weighted average basic shares outstanding and assumes up to $600 million of additional equity in 2017. The current and deferred income tax effect was calculated by applying the subsidiaries' statutory tax rate to the pre-tax amount. The income tax rates range from 37% to 42%.

2016A – 2017F Special Items(1)

- **Mark-to-market adjustments**
  - **Pension/OPEB actuarial assumptions** – Reflects changes in fair value of plan assets and net actuarial gains and losses associated with the company's pension and other postemployment benefit plans
  - **Other** – Primarily reflects non-cash mark-to-market gains and losses on commodity contract positions
- **Merger accounting – commodity contracts** – Primarily reflects the non-cash amortization of acquired commodity contracts from the Allegheny Merger
- **Regulatory charges** – Primarily reflects the impact of regulatory orders requiring certain commitments and/or disallowing the recoverability of costs
- **Trust securities impairments** – Primarily reflects non-cash other than temporary impairment charges on nuclear decommissioning trust assets
- **Asset impairments/plant exit costs** – Primarily reflects impairment charges resulting from management's plans to exit competitive operations by mid-2018 and the anticipated cash flows over this shortened period as well as impairment charges resulting from management's decision to exit the Bayshore Unit 1 generating station and Units 1-4 of the W.H. Sammis generating station and the impairment of goodwill at CES
- **Debt redemptions costs** – Primarily reflects costs associated with the early redemption and retirement of debt

(1) Special items represent charges incurred or benefits realized that management believes are not indicative of, or may obscure trends useful in evaluating the company's ongoing core activities and results of operations or otherwise warrant separate classification. Special items are not necessarily non-recurring.

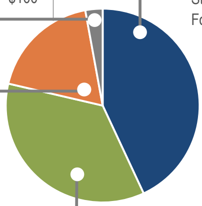
Capital Expenditures Forecast Summary

	2016A	2017F	2018F	2019F
FE Consolidated	$2.9B	$2.8B	$2.7B	$2.4B

($ Millions)	2016A	2017F	2018F	2019F
Regulated Distribution	**$1,281**	**$1,325**	**$1,305**	**$1,265**
Stated Rate	$791	$815	$830	$875
Formula Rate	$490	$510	$475	$390

($ Millions)	2016A	2017F	2018F	2019F
Corp / Other	$93	$95	$90	$100

($ Millions)	2016A	2017F	2018F
CES	**$550**	**$365**	**$290**
Baseline - FENOC*	$191	$190	$175
Baseline - Fossil	$158	$120	$90
Major Projects	$201	$55	$25



85+% of 2017F-2019F capital expenditures for Regulated Operations

* Excludes nuclear fuel

($ Millions)	2016A	2017F	2018F	2019F	2020F	2021F
Regulated Transmission	**$1,001**	**$1,000**	**$800-$1,200**	**$800-$1,200**	**$800-$1,200**	**$800-$1,200**
Stated Rate	$297	$90	$90	$95	$95	$95
Formula Rate	$704	$910	$710-$1,110	$705-$1,105	$705-$1,105	$705-$1,105

All capital expenditures throughout the materials exclude the capital component of year-end Pension/OPEB mark-to market adjustment

2016A-2017F Funds From Operations

($ Millions)	FE Consolidated	
	2016A	2017F
Cash From Operations	$3,371	$3,710 - $3,910
Working Capital/Collateral/Other (1)	(50)	15 – (85)
Pension Contribution (2)	382	-
Funds From Operations (Non-GAAP)	$3,703	$3,725 - $3,825

(1) Primarily includes changes in working capital and cash collateral, net which are included in "Changes in Current Assets and Liabilities" on the Consolidated Statements of Cash Flows

(2) Pension Contribution is included in "Pension Trust Contributions" on the Consolidated Statements of Cash Flows

Funds from Operations (FFO) is a non-GAAP measure and represents cash from operations less changes in working capital and collateral plus pension trust contributions. FFO is used by management to monitor its credit metrics consistent with credit rating agencies.

2016A-2017F Free Cash Flow

($ Millions)	FE Consolidated	
	2016A	2017F
Funds From Operations (FFO) (Non-GAAP)	**$3,703**	**$3,725 - $3,825**
Capital Expenditures [1]	(2,888)	(2,755)
Nuclear Fuel	(232)	(175)
Cash Before Other Items	**$583**	**$795 - $895**
Pension Contribution	(382)	-
Asset Sale Proceeds, Net of Make Whole Premium	-	815
Working Capital/Collateral/Other [2]	(83)	(175) – (155)
Cash Before Dividends and Equity	**$118**	**$1,435 - $1,555**
Dividends	(611)	(640)
Equity	-	500
Free Cash Flow [3] (Non-GAAP)	**($493)**	**$1,295 - $1,415**

(1) Excludes capital component of year-end Pension/OPEB mark-to-market adjustment and AFUDC equity

(2) Primarily includes changes in working capital and cash collateral, net which are included in "Changes in Current Assets and Liabilities" on the Consolidated Statements of Cash Flows, asset removal costs which is included in the Consolidated Statements of Cash Flows, NDT interest and dividend income which is included in "Purchases of Investment Securities Held in Trust" on the Consolidated Statements of Cash Flows

(3) Excludes cash used to fund debt redemptions and from new debt financings in 2017

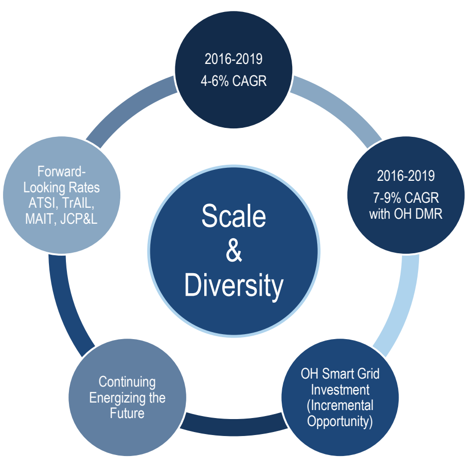
Free Cash Flow (FCF) is a non-GAAP measure and represents funds from operations less capital expenditures, nuclear fuel purchases, pension trust contributions, and dividends as well as changes in collateral and working capital. FCF is used by management to evaluate the net cash flow from operations less capital and capital related investments and dividends.

FIRSTENERGY   **Unlocking Value** for Investors

Regulated

Investing for Growth in the Regulated Business

The scale and diversity of our regulated operations position FirstEnergy for sustained growth into the future



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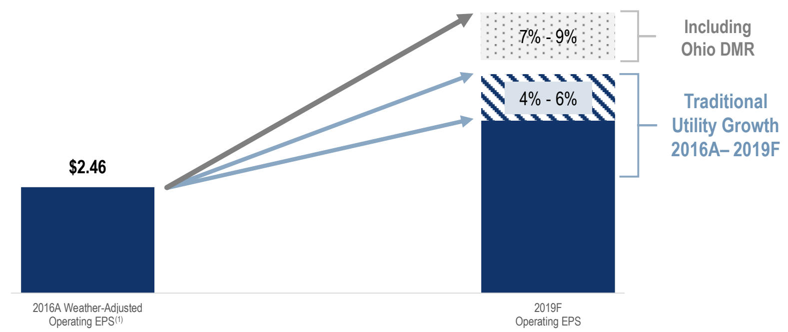
Regulated

Regulated Operating Earnings Growth



Targeting 4% - 6% Compound Annual Growth Rate
Incremental 3% with Ohio DMR

(1) The CAGR is calculated using an 2016A operating earnings for Regulated Distribution and Regulated Transmission segments of $2.46 per share which includes ($0.13) from the impact of weather

Regulated Distribution

Weather-Adjusted Distribution Deliveries

Total Deliveries

M MWH	2016A	2017F	2018F	2019F	2016A-2019F CAGR %
Total	**146.5**	**146.2**	**147.0**	**147.3**	**0.2%**
OH	52.6	52.2	52.4	52.5	-0.1%
PA	51.5	51.5	51.3	51.1	-0.2%
WV	15.0	15.4	16.3	16.9	4.2%
NJ	20.5	20.0	19.8	19.6	-1.4%
MD	6.9	7.1	7.2	7.2	1.3%

Residential

M MWH	2016A	2017F	2018F	2019F	2016A-2019F CAGR %
Sub-Total	**53.3**	**51.6**	**51.8**	**51.7**	**-1.0%**
OH	17.0	16.8	16.8	16.9	-0.1%
PA	18.3	17.2	17.4	17.3	-1.9%
WV	5.5	5.4	5.5	5.5	0.3%
NJ	9.3	8.9	8.8	8.7	-2.3%
MD	3.2	3.3	3.3	3.3	0.5%

Commercial

M MWH	2016A	2017F	2018F	2019F	2016A-2019F CAGR %
Sub-Total	**43.1**	**42.7**	**42.6**	**42.3**	**-0.6%**
OH	15.3	15.2	15.2	15.1	-0.6%
PA	13.0	12.8	12.8	12.7	-0.7%
WV	3.7	3.7	3.7	3.7	-
NJ	9.0	8.9	8.8	8.7	-1.1%
MD	2.1	2.1	2.1	2.1	0.7%

Industrial

M MWH	2016A	2017F	2018F	2019F	2016A-2019F CAGR %
Sub-Total	**50.1**	**51.9**	**52.6**	**53.3**	**2.2%**
OH	20.3	20.2	20.4	20.5	0.4%
PA	20.2	21.5	21.1	21.1	1.5%
WV	5.8	6.3	7.1	7.7	9.9%
NJ	2.2	2.2	2.2	2.2	0.8%
MD	1.6	1.7	1.8	1.8	3.6%

Guidance Sensitivities

Estimated Impact of Annual Retail Sales Volumes	
+ / - 1% Change in Residential MWH Sold	~$0.02/share
+ / - 1% Change in Commercial MWH Sold	~$0.01/share
+ / - 1% Change in Industrial MWH Sold	~$0.004/share

Weather Impact on Residential/Commercial Sales Volumes	
+ / - 90 HDD vs. normal (Dec-Mar)	~$0.01/share
+ / - 30 CDD vs. normal (June-Sept)	~$0.01/share

Regulated Distribution Capital Plan (2016A - 2017F)

$ Millions		Stated Rate		Formula Rate		Total	
		2016A	2017F	2016A	2017F	2016A	2017F
OH	CEI	$30	$30	$103	$95	$133	$125
	OE	30	30	126	115	156	145
	TE	10	10	34	35	44	45
	Sub-total	**70**	**70**	**263**	**245**	**333**	**315**
NJ	**JCP&L**	**191**	**180**	**0**	**0**	**191**	**180**
PA	ME	76	90	31	45	107	135
	PN	94	110	51	50	145	160
	PP	27	20	20	25	47	45
	WPP	106	105	43	70	149	175
	Sub-total	**303**	**325**	**145**	**190**	**448**	**515**
WV / MD	MP	144	150	72	60	216	210
	PE	83	90	10	15	93	105
	Sub-total	**227**	**240**	**82**	**75**	**309**	**315**
Total		**$791**	**$815**	**$490**	**$510**	**$1,281**	**$1,325**

Regulated Transmission Capital Plan (2016A - 2021F)

$ Millions	2016A	2017F	2018F	2019F	2020F	2021F
Former Allegheny (WPP/MP/PE)	$53	$90	$90	$95	$95	$95
Former GPU (ME/PN)	55	-	-	-	-	-
JCP&L	189	-	-	-	-	-
Stated Rate Sub-total	**297**	**90**	**90**	**95**	**95**	**95**
ATSI	487	420	270 - 470	290 - 490	300 - 500	300 - 500
TrAIL Co.	217	60	35	30	25	25
MAIT	-	260	280 - 480	260 - 460	250 - 450	250 - 450
JCP&L	-	170	125	125	130	130
Formula Rate Sub-total	**704**	**910**	**710 - 1,110**	**705 - 1,105**	**705 - 1,105**	**705 - 1,105**
Regulated Transmission – Total	**$1,001**	**$1,000**	**$800 - $1,200**	**$800 - $1,200**	**$800 - $1,200**	**$800 - $1,200**
Last 2 Years of Our 2014-2017 Energizing the Future Plan	**~$2B**					
Continuing Our Energizing the Future Plan		**$4.2B - $5.8B**				

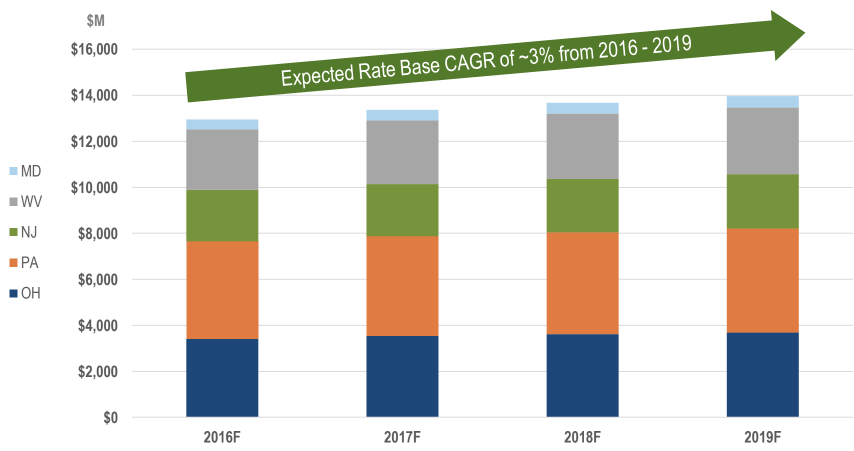
Regulated Transmission Capital Opportunities

$ Millions	Phase 2 Energizing The Future 2017F - 2021F	Future Opportunities Beyond 2021F
ATSI	$1,580 - $2,380	• Existing transmission infrastructure creates $1B+ in reliability improvement investment opportunities annually
TrAIL Co.	175	
MAIT	1,300 - 2,100	
JCP&L	680	
Formula Rates Sub-total	**$3,735 - $5,335**	
Stated Rates	465	
Regulated Transmission – Total	**$4,200 - $5,800**	**$20,000+**

Long runway for growth to increase reliability for customers

Regulated Distribution

Regulated Distribution Rate Base Growth (2016F-2019F)



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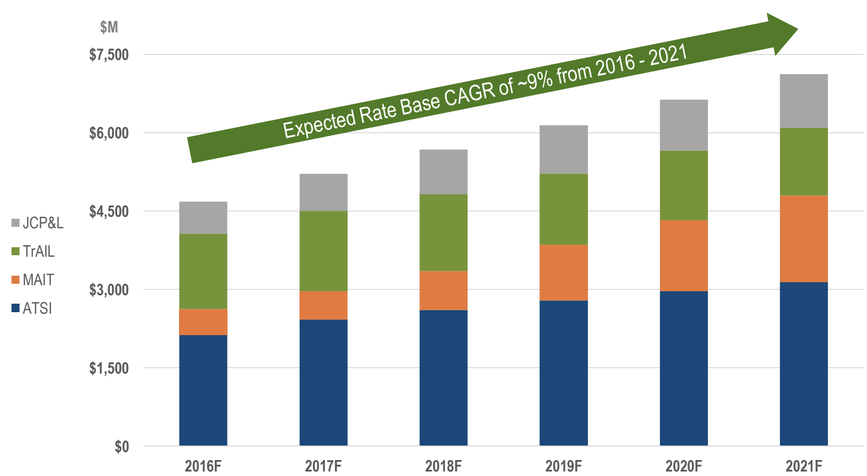
Regulated Transmission

Regulated Transmission Rate Base Growth (2016F-2021F)

Formula Rate Transmission Companies



Note: 2018F – 2021F assumes midpoint of ~$900M per year of Regulated Transmission formula rate spend

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Competitive Guidance Support

FIRSTENERGY **Unlocking Value** for Investors

Competitive

2016A Adjusted EBITDA
Competitive Energy Services

		Average $/MWh		2016A ($M)
Contract Sales: 53M MWH	×	$54 Contract Rate *less* ($18) Supply Cost *less* ($16) Delivery Cost **$20 avg. net margin**	=	$1,060
Wholesale: 15M MWH[1]	×	$28 Wholesale Price *plus* $7 Financial Gain *less* ($18) Supply Cost **$17 avg. net margin**	=	$255

(Excludes ~3M MWH of annual distribution losses/pumping)

Capacity Revenue	=	$815
Other Revenue	=	$178
Other Operating Expenses	=	($1,334)
CES 2016A Adjusted EBITDA[2]	=	**$974**

See slide 32 for additional notes describing the line items

[1] 12M MWH notional amount of Q1-Q4 wholesale sales were hedged financially

[2] Total CES 2016A Adjusted EBITDA, a non-GAAP financial measure, is reconciled to 2016A CES Net Income on slide 37

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Competitive

Notes on 2016A Adjusted EBITDA

Competitive Energy Services

Contract Sales:	▪ Includes actual physical volume of contract sales through 12/31/2016 ▪ Contract Rate represents average realized rate based on actual committed contract prices and customer usage ▪ Supply Cost rate represents the overall realized cost of all supply sources to serve contract sales obligations, including Fuel (coal, natural gas and nuclear fuel amortization) and Purchased Power (firm and spot purchased power). Average Fossil fuel rate = $24/MWH and Average Nuclear fuel rate = $7/MWH. ▪ Delivery Cost rate represents the average realized capacity and transmission expenses, including delivery expenses associated with serving loads and net of transmission revenues (including Financial Transmission Rights and ancillary services)
Wholesale:	▪ Includes actual volume of physical wholesale spot sales at the average realized price and Financial Gains through 12/31/2016 ▪ Financial Gains represent the impact of realized gains on settlement of forward financially-settled transactions
Capacity Revenue:	▪ Capacity revenue includes revenues from legacy BRA, incremental/transitional capacity auctions, bilateral transactions and capacity transmission rights
Other Revenue:	▪ Annual non-commodity revenue primarily comprised of lease revenue on sale and leaseback transactions and other affiliated transactions, that is included in "Revenues – Unregulated Businesses" on the Consolidated Statements of Income ▪ Excludes Investment Income that is excluded from Adjusted EBITDA (see slide 37)
Other Operating Expenses:	▪ Annual expenses related primarily to generation, retail, corporate support and general taxes that are included in "Other Operating Expenses" on the Consolidated Statements of Income ▪ Excludes Income Taxes, Depreciation, Amortization and Interest Expense, net that is excluded from Adjusted EBITDA (see slide 37)

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Competitive

2017F Adjusted EBITDA

Competitive Energy Services

	Average $/MWh		2017F ($M)
Committed Contract Sales: 37M MWH ×	$51 Contract Rate *less* ($18) Supply Cost *less* ($14 - $15) Delivery Cost **$18 - $19 avg. net margin**	=	**$665 - $700**
2017 Open: 28M MWH **2017 Financially-Hedged:** 5M MWH **Total 2017 Wholesale: 33M MWH** × (Excludes ~2M MWH of annual distribution losses)	$30 - $32 Wholesale Price *plus* $2 - $1 Financial Gain *less* ($18) Supply Cost **$14 - $15 avg. net margin**	=	**$460 - $495**
	Capacity Revenue	=	**$545**
	Other Revenue	=	**$75**
	Other Operating Expenses	=	**($1,340)**
	CES 2017F Adjusted EBITDA(1)	=	**$405 - $475**

See slide 34 for additional notes describing the line items

(1) Total CES 2017F Adjusted EBITDA, a non-GAAP financial measure, is reconciled to 2017F CES Net Income on slide 37, and is based on market prices as of December 31, 2016

Excludes the contribution of 1,572 MW of AE Supply assets beginning in the third quarter of 2017 (sale pending)

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Notes on 2017F Adjusted EBITDA

Competitive Energy Services

Committed Contract Sales:	▪ Includes expected physical volume of contract sales ▪ Volume is subject to fluctuations due to weather and customer behavior ▪ Contract Rate represents average expected rate based on committed contract prices and customer usage. Portions of "committed" governmental aggregation sales are not priced-fixed as they are indexed to utility price-to-compare ▪ Supply Cost rate represents the overall average expected cost of all supply sources to serve contract sales obligations, including Fuel (coal, natural gas, and nuclear fuel amortization) and Purchased Power (firm and spot purchased power) Average Fossil fuel rate = \$24-\$25/MWH and Average Nuclear fuel rate = \$7/MWH ▪ Delivery Cost rate represents the average expected capacity and transmission expenses, including delivery expenses associated with serving loads and net of transmission revenues (including Financial Transmission Rights and ancillary services)
Total 2017 Wholesale:	▪ Includes expected physical volume of wholesale spot sales given current Committed Contract Sales at a range of expected realized prices at CES' generation resources and based on 2/8/2017 market forwards. Includes volumes that may be sold through incremental Contract Sales ▪ A portion of the total expected volume of physical spot sales into PJM is price-hedged through forward financial transactions that will settle at 2017 market prices. Financial gain range is based on expected settlement value of the notional amount of firm forward financial wholesale sales transactions at a forward AD Hub price range of \$30-\$32/MWH. ▪ Volume is subject to energy market prices and generating unit performance
Capacity Revenue:	▪ Capacity revenue includes revenues from Base Residual/Capacity Performance auctions, incremental/transitional capacity auctions, bilateral transactions and capacity transmission rights
Other Revenue:	▪ Projected annual non-commodity revenue primarily comprised of lease revenue on sale and leaseback transactions and other affiliated transactions, that is included in "Revenues – Unregulated Businesses" on the Consolidated Statements of Income ▪ Excludes Investment Income that is excluded from Adjusted EBITDA (see slide 37)
Other Operating Expenses:	▪ Projected annual expenses related primarily to generation, retail, corporate support and general taxes that are included in "Other Operating Expenses" on the Consolidated Statements of Income ▪ Excludes Income Taxes, Depreciation, Amortization and Interest Expense, net, that is excluded from Adjusted EBITDA (see slide 37)

2018F Adjusted EBITDA

Competitive Energy Services

		Average \$/MWh			2018F (\$M)
Committed Contract Sales: 20M MWH	×	\$50	Contract Rate	=	**\$320 - \$340**
		less (\$18)	Supply Cost		
		less (\$15 - \$16)	Delivery Cost		
		\$16 - \$17 avg. net margin			
2018 Open: 45M MWH **2018 Financially-Hedged:** 1M MWH **Total 2018 Wholesale: 46M MWH** (Excludes ~1M MWH of distribution losses)	×	\$29 - \$31	Wholesale Price	=	**\$550 - \$645**
		plus \$1	Financial Gain		
		less (\$18)	Supply Cost		
		\$12 - \$14 avg. net margin			
		Capacity Revenue		=	**\$545**
		Other Revenue		=	**\$20**
		Other Operating Expenses		=	**(\$1,340)**
		CES 2018F Adjusted EBITDA[(1)]		=	**\$95 - \$210**

See slide 36 for additional notes describing the line items

[(1)] Total CES 2018F Adjusted EBITDA, a non-GAAP financial measure, is reconciled to 2018F CES Net Income on slide 37, and is based on market prices as of December 31, 2016

Excludes the contribution of 1,572 MW of AE Supply assets beginning in the third quarter of 2017 (sale pending)

Competitive

Notes on 2018F Adjusted EBITDA

Competitive Energy Services

Committed Contract Sales:	▪ Includes expected physical volume of contract sales. ▪ Volume is subject to fluctuations due to weather and customer behavior. ▪ Contract Rate represents average expected rate based on committed contract prices and customer usage. Portions of "committed" governmental aggregation sales are not priced-fixed as they are indexed to utility price-to-compare. ▪ Supply Cost rate represents the overall average expected cost of all supply sources to serve contract sales obligations, including Fuel (coal, natural gas and nuclear fuel amortization) and Purchased Power (firm and spot purchased power). Average Fossil fuel rate = $25/MWH and Average Nuclear fuel rate = $7/MWH. ▪ Delivery Cost rate represents the average expected capacity and transmission expenses, including delivery expenses associated with serving loads and net of transmission revenues (including Financial Transmission Rights and ancillary services).
Total 2018 Wholesale:	▪ Includes expected physical volume of wholesale spot sales given current Committed Contract Sales. Includes volumes that may be sold through incremental Contract Sales. ▪ Volume is subject to energy market prices and generating unit performance.
Capacity Revenue:	▪ Capacity revenue includes revenues from Base Residual/Capacity Performance auctions, incremental/transitional capacity auctions, bilateral transactions and capacity transmission rights.
Other Revenue:	▪ Projected annual non-commodity revenue primarily comprised of lease revenue on sale and leaseback transactions and other affiliated transactions, that is included in "Revenues – Unregulated Businesses" on the Consolidated Statements of Income. ▪ Excludes Investment Income that is excluded from Adjusted EBITDA (see slide 37).
Other Operating Expenses:	▪ Projected annual expenses related primarily to generation, retail, corporate support and general taxes, that is included in "Other Operating Expenses" on the Consolidated Statements of Income. ▪ Excludes Income Taxes, Depreciation, Amortization and Interest Expense, net, that is excluded from Adjusted EBITDA (see slide 37).

Competitive

Net Income (Loss) to Adjusted EBITDA[1] Reconciliation

Competitive Energy Services

($ Millions)	2016A	2017F	2018F
Net Income (Loss) – GAAP	($6,919)	$5 - $55	($130) - ($30)
Special Items (after tax)(1)	7,175	85	-
Operating Earnings (Loss)	$256	$90 - $140	($130) - ($30)
Income Taxes(2)	160	45 - 80	(50) - (20)
Interest Expense, Net	150	145 - 135	135 - 125
Depreciation	387	120 - 115	135 - 130
Amortization(3)	104	55	55
Investment Income	(83)	(50)	(50)
Adjusted EBITDA(1)	$974	$405 - $475	$95 - $210

(1) Adjusted EBITDA is a non-GAAP measure and represents GAAP net loss adjusted for special items listed on slides 12-16 and the addition of Income Taxes; Interest Expense, net; Depreciation, Amortization and Investment Income

(2) Income taxes excluding the tax effect of special items as summarized on slides 12-16

(3) Amortization expense included in Other Operating Expenses on the Consolidated Statements of Income. Primarily related to amortization of customer contract intangible assets, as disclosed in Form 10-K Note 8 – Intangible Assets, including a $37M non-cash charge in 2016 associated with the termination of an FES customer contract, deferred costs on sale leaseback transaction, net, and $3M in fossil fuel amortization as disclosed in the Consolidated Statements of Cash Flows and $3M for non-cash amortization related to a fossil fuel contract that is included in Fuel expense on the Income Statement. Does not include nuclear fuel amortization of approximately $224M, $210M, and $215M in 2016, 2017, and 2018, respectively.

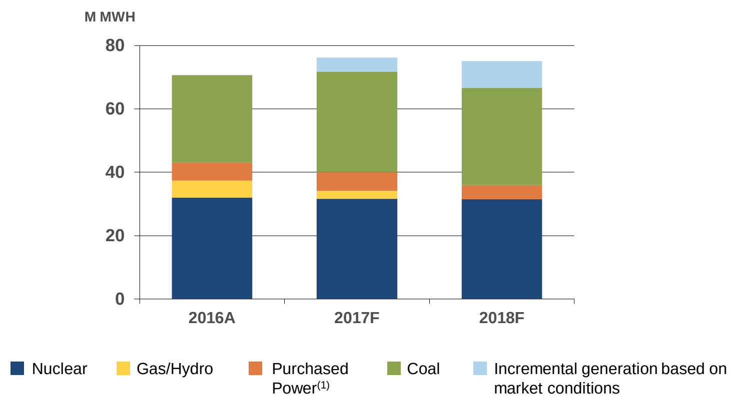
Guidance Sensitivities

Sensitivities on Open Position to Adjusted EBITDA		
Sensitivity	2017	2018
+ / - $5/MWH ATC Energy Prices	$140M	$225M
Fuel Cost Exposure		
+ / - $1/MMBTU Natural Gas	$15M	-
+ / - $5/Ton Eastern Coal	$10M	$50M
+ / - $1/MWH Nuclear Fuel	-	-

Hedged Fuel Percentages		
	2017	2018
Coal (Volume)	85 - 90%	70 - 75%
Coal (Price)	85 - 90%	20 - 25%
Nuclear Fuel	100%	100%

Nuclear Refueling Outage Impact	
Average O&M Expense per RFO	~$45M
+ / - 1 RFO	~$0.07/share

CES Generation Forecast (2016A-2018F)



Available generation resources of ~75 - 80M MWH annually (2)

(1) Purchased Power includes renewables/OVEC and additional bilateral and spot purchases

(2) Excludes ~5M MWH of AE Supply assets; sale pending

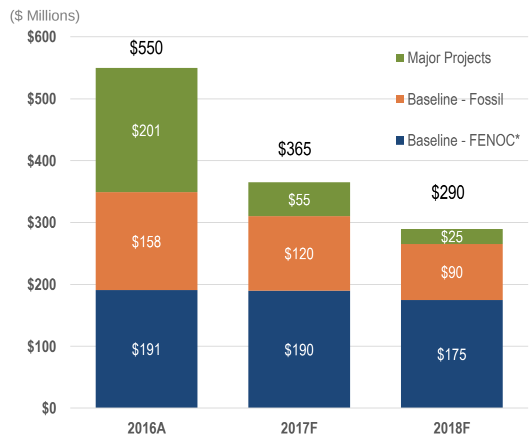
Competitive

Competitive Energy Services Capital Plan (2016A - 2018F)

Decreasing major projects spend due to completion of Mansfield Dewatering Facility, MATS spend, and the delay of the BV2 steam generator & reactor head replacement

Baseline fossil spend of $100M-$150M annually to ensure safety and preserve strategic options going forward

Baseline nuclear spend of $175M-$195M annually to ensure safety, maintain assets and meet regulatory standards



* Excludes nuclear fuel

Competitive

2016A-2018F CES Funds From Operations

($ Millions)	Competitive Energy Services		
	2016A	2017F	2018F
Net Income (Loss) – GAAP	**($6,919)**	**$5 - $55**	**($130) - ($30)**
Income Tax (Benefits)[1]	(3,498)	0 - 20	(50) - (20)
Income (Loss) Before Income Tax Benefits	**(10,417)**	**5 - 75**	**(180) - (50)**
Cash Receipts (Payments) on Income Tax Benefits[2]	(10)	30 - 40	270 - 245
Depreciation & Amortization[3]	715	380 - 385	395 - 400
Asset Impairments[4]	10,665	-	-
Make-Whole Payment	-	110	-
Lease Payments on Sale & Leaseback Transactions	(120)	(75)	(100)
Pension/OPEB Mark-to-Market Adjustment[4]	45	-	-
Other[5]	82	80	125 - 115
Funds From Operations (Non-GAAP)	**$960**	**$530 - $615**	**$510 - $610**

[1] Income Taxes include the current and deferred tax effect on GAAP earnings
[2] Current tax receipts (payments) under inter-company tax sharing agreement with FirstEnergy affiliates
[3] Depreciation & Amortization includes nuclear fuel amortization of approximately $224M, $210M, and $215M in 2016, 2017, and 2018, respectively, and Depreciation & Amortization on slide 37
[4] Includes non-cash impairment of assets as included in CES' Results of Operations
[5] Other primarily includes other non-cash items

Funds from Operations (FFO) is a non-GAAP measure that management uses to monitor its credit metrics consistent with credit rating agencies

Competitive

2016A-2018F CES Free Cash Flow

($ Millions)	Competitive Energy Services		
	2016A	2017F	2018F
Funds From Operations (FFO) (Non-GAAP)	**$960**	**$530 - $615**	**$510 - $610**
Capital Expenditures[(1)]	(550)	(365)	(290)
Nuclear Fuel	(232)	(175)	(195)
Cash Before Other Items	**$178**	**($10) - $75**	**$25 - $125**
Pension Contribution	(188)	-	-
Sale-Leaseback Repurchases	(50)	(40)	-
Asset Sale Proceeds, Net	-	815	-
Collateral	(103)	70	-
Working Capital/Other[(2)]	69	(270)	(15)
Free Cash Flow[(3)] (Non-GAAP)	**($94)**	**$565 - $650**	**$10 - $110**

(1) Excludes capital component of any year-end Pension/OPEB mark-to-market adjustment

(2) Primarily includes changes in working capital which is included in "Changes in Current Assets and Liabilities" on the Consolidated Statements of Cash Flows, "except for cash collateral, net", NDT interest and dividend income which is included in "Purchases of Investment Securities Held in Trust" on the Consolidated Statements of Cash Flows, and non-cash stock based compensation expense included in Form 10-K "Note 5. Stock-Based Compensation Plans"

(3) Excludes cash used to fund debt redemptions and from new debt financings in 2017 and 2018

Free Cash Flow (FCF) is a non-GAAP measure and represents funds from operations less capital expenditures, nuclear fuel purchases and pension trust contributions, as well as changes in collateral and working capital. FCF is used by management to evaluate the net cash flow from operations less capital and capital related investments.

Competitive

PJM RPM Capacity Auctions

Base Residual (BR) and Capacity Performance (CP) Transitional Auction Results

Price per MW-Day		ATSI	RTO	MAAC	EMAAC	ComEd
2016/2017	BR	$114.23	$59.37	$119.13		$59.37
	CP	$134.00				
2017/2018	BR	$120.00				
	CP	$151.50				
2018/2019	Base	$149.98			$210.63	$200.21
	CP	$164.77			$225.42	$215.00
2019/2020	Base	$80.00			$99.77	$182.77
	CP	$100.00			$119.77	$202.77

Net Competitive Capacity Position (MW)

	2016 / 2017			2017 / 2018 (1)			2018 / 2019 (1)			2019 / 2020 (1)		
	Legacy	CP	Uncommitted	Legacy	CP	Uncommitted	Base	CP	Uncommitted	Base	CP	Uncommitted
ATSI	2,765	4,210	615	375	6,245	200	-	6,245	525	-	5,680	1,075
RTO	875	3,675	120	45	3,100	-	10	2,885	235	10	2,710	460
All Other Zones	135	-	10	115	-	-	35	20	-	35	20	-
TOTAL	3,775	7,885	745	535	9,345	200	45	9,150	760	45	8,410	1,535

(1) Excludes AE Supply assets currently pending sale. Please see slide 54, footenote 2 for details.

Competitive

Market Prices: Historical Basis Values

A negative value means the Locational Marginal Price (LMP)[1] at the source is greater than the LMP at the sink

Source	Sink	2015 ($/MWH)	2016[2] ($/MWH)
FE OH	Ill Hub	(6.01)	(1.63)
FE OH	Comed	(4.66)	(1.80)
FE OH	DTE	(3.73)	(0.06)
FE OH	MichFE	(4.09)	(0.27)
FE OH	PJM West Hub	3.14	.93
FE OH	DQE	(1.73)	(0.67)
FE OH	AD Hub	(1.19)	(0.45)
FE OH	AEP	(0.47)	(0.10)
FE OH	Duke Ohio	(0.85)	(0.51)
Allegheny Power System	AD Hub	(3.53)	(.96)
Allegheny Power System	DQE	(4.07)	(1.17)
Allegheny Power System	PJM West Hub	0.80	0.43
Allegheny Power System	Penelec	(1.37)	(2.02)
PJM West Hub	PPL	(2.81)	(4.98)
PJM West Hub	PSEG	(0.65)	(4.35)
PJM West Hub	PECO	(2.69)	(5.21)
PJM West Hub	JCP&L	(2.02)	(4.92)
PJM West Hub	Met-Ed	(2.88)	(4.54)
PJM West Hub	Penelec	(2.17)	(2.45)

(1) Values shown are around-the-clock, day-ahead average basis values (2) As of December 31, 2016

FIRSTENERGY **Unlocking Value** for Investors

Financial

Financial Plan

- **Continued focus on Regulated Transmission growth; expected combination of $500M equity in each year 2017-2019 and long-term financings to support growth**
- **Continued focus on strengthening Regulated Distribution balance sheets**
- **Expect positive free cash flow at CES in each year 2017 and 2018**
- **Continue to issue ~$100M equity annually through the stock investment and employee benefit plans**

Committed to investment-grade credit ratings
at all regulated entities

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Debt Financing Plan (2017F – 2019F)

FE Corp

Year	Entity	Amount	Purpose
2018	FE Corp	$650M	$650M at 2.75% maturing 3/15/18

Competitive Energy Services

Year	Entity	Amount	Purpose
2017	FG	$129.6	PCRB mandatory put date 6/1/17
2018	NG	$98.9M	PCRB mandatory put date 4/2/18
	FG	$141.3M	PCRB final maturity 6/1/18
	NG	$15.2M	PCRB mandatory put date 7/2/18
	FG	$260.5M	PCRB mandatory put date 12/3/18

Regulated Distribution

Year	Entity	Amount	Purpose
2017	CEI	$350M	$130M at 5.7% maturing 4/1/17 $300M at 7.88% maturing 11/1/17
	MP	$300M	$150M at 5.7% maturing 3/15/17
	PN	$300M	$300M at 6.05% maturing 9/1/17
	MP	$73.5M	PCRB Refinancing 10/15/17
2018	CEI	$250M	$300M at 8.875% maturing 11/15/18
	JCP&L	$150M	$150M at 4.8% maturing 6/15/18
2019	JCP&L	$300M	$300M at 7.35% maturing 2/1/19
	ME	$300M	$300M at 7.7% maturing 1/15/19
	PN	$125M	$125M at 6.625% maturing 4/1/19

Regulated Transmission

Year	Entity	Amount	Purpose
2017	ATSI	$150M	New Issuance
2018	ATSI	$125M	New issuance
	FET	$150M	New issuance
	MAIT	$455M	New issuance
2019	MAIT	$150M	New issuance

Financial – Pension/OPEB Overview

- **FE is the administrator and guarantor for employees at all of FE's subsidiaries**
- **Pension Status is Open**
  - The plan design was changed to a Cash Balance formula for new hires beginning 1/1/2014
    - Employees hired before 1/1/2014 are covered under a Final Average Pay formula
- **Pension/OPEB Expense impacts Operating Earnings based on a post-capitalization calculation of net periodic costs (excluding mark-to-market adjustment)**
  - Key assumptions for 2016 expense include:
    - Expected Return on Assets of 7.50%
    - Discount Rate (beginning of year): 4.50% (Pension) / 4.25% (OPEB)
  - Key assumptions for 2017 expense include:
    - Expected Return on Assets of 7.50%
    - Discount Rate (beginning of year): 4.25% (Pension) / 4.00% (OPEB)
- **Regulated Utility Recovery**
  - **Pension**
    - PA: Based on historical contributions of the last 10 years
    - OH: Current year service costs
    - MD: GAAP Expense
    - WV: GAAP Expense (Last rate case was settled, but included GAAP Expense with modified MTM adjustments)
    - NJ: Delayed recognition method (amortization of accumulated net gains/losses over future period)
  - **OPEB**
    - PA: Service cost in 2017 test year (as originally filed for in 2016 rate case – the method of calculating or the amount included in the settlement was not specified)
    - OH: Current year service costs
    - MD: GAAP Expense
    - WV: GAAP Expense (Last rate case was settled, but included GAAP Expense with modified MTM adjustments)
    - NJ: Delayed recognition method (amortization of accumulated net gains/losses over future period)

Financial – Pension/OPEB Overview

- **Pension/OPEB Funded Status: Year-End 2016 Actual**

$ Millions	Corp	FEU	FES	FENOC	Total	Notes
Qualified Pension	($1,346)	($746)	($135)	($594)	($2,821)	$500M equity contribution in December 2016, no funding requirement until 2018
Non-Qualified Pension	(163)	(164)	(23)	(42)	(392)	No minimum funding requirements
OPEB	51	(424)	36	46	(291)	No minimum funding requirements
Total	**($1,458)**	**($1,334)**	**($122)**	**($590)**	**($3,504)**	

- **Components of Net Periodic Benefit Costs: 2015A-2017F (excluding Pension/OPEB mark-to-market adjustment)**

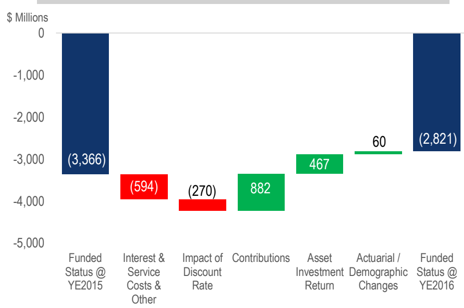
	Pension			OPEB			Total		
$ Millions	2015A	2016A	2017F	2015A	2016A	2017F	2015A	2016A	2017F
Service Cost	$193	$191	$210	$5	$5	$5	$198	$196	$215
Interest Cost	383	398	390	29	30	30	412	428	420
Expected Return on Assets	(443)	(399)	(450)	(33)	(30)	(30)	(476)	(429)	(480)
Amortization of prior service cost (credit)	8	8	5	(134)	(80)	(80)	(126)	(72)	(75)
Net Periodic Cost (Credit)	**$141**	**$198**	**$155**	**($133)**	**($75)**	**($75)**	**$8**	**$123**	**$80**

- **Post-Capitalization – Net Periodic Benefit Costs: 2015A-2017F (excluding Pension/OPEB mark-to-market adjustment)**

	Pension			OPEB			Total		
$ Millions	2015A	2016A	2017F	2015A	2016A	2017F	2015A	2016A	2017F
Utilities	$23	$55	$30	($49)	($22)	($20)	($26)	$33	$10
FES / FENOC	71	88	90	(41)	(30)	(35)	30	58	55

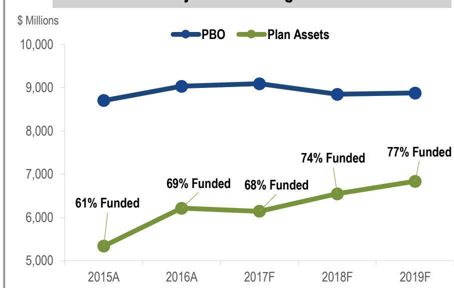
Qualified Pension – Additional Details

2016A Funded Status



- Key assumptions:
  - Actual Investment Return of 8.6% vs. Expected Return on Assets of 7.50%
  - Discount Rate of 4.50% BOY; 4.25% EOY
    - 25 bps change in discount rate → ~$270M change in liability
  - No impact of actuarial changes, which are updated annually based on participant census data

Projected Funding Levels



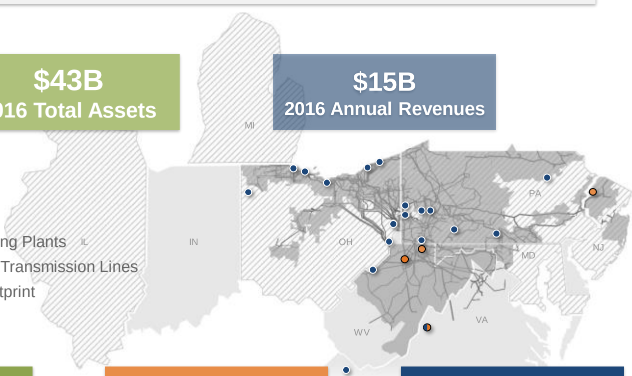
- Key assumptions:
  - Expected Return on Assets of 7.50%
  - Discount Rates at year-end:
    - 2015A – 4.50%
    - 2016A – 4.25%
    - 2017F – 4.25%
    - 2018F – 4.50%
    - 2019F – 4.50%
  - $500M Equity Contribution in December 2016

FirstEnergy Overview

OUR MISSION
We are a forward-thinking electric utility powered by a diverse team of employees committed to making customers' lives brighter, the environment better and our communities stronger.

$43B 2016 Total Assets

$15B 2016 Annual Revenues



- Jointly Owned Plant
- Regulated Plants
- Competitive Generating Plants
- 230, 345 and 500 kV Transmission Lines
- Competitive retail footprint
- Utility footprint

~6 Million Total Customers

~24,200+ Miles Transmission Lines

~17,000 MW Total Generation

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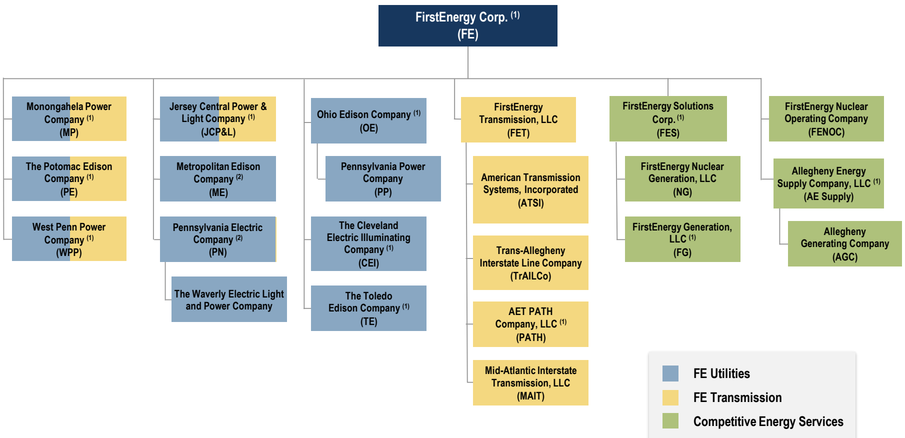
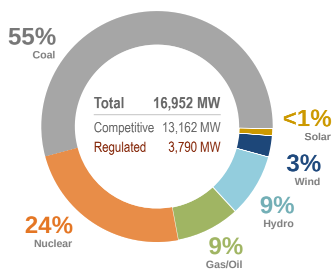
Summary Organizational Structure



(1) Entity has subsidiaries that are not shown
(2) Transfer of transmission assets was completed on January 31, 2017

Generation Portfolio



	MW
Mansfield 1-3	2,490
Harrison 1-3 (R)	1,984
Pleasants 1 & 2	1,300
Sammis 6 & 7	1,200
Fort Martin 1 & 2 (R)	1,098
Total Supercritical Coal	**8,072**
Sammis 1-4 (1)	720
Sammis 5	290
Bay Shore 1 (1)	136
OVEC	188
Regulated: 11 Competitive: 177	
Total Subcritical Coal	**1,334**

Beaver Valley 1 & 2	1,872
Perry	1,268
Davis-Besse	908
Total Nuclear	**4,048**

	MW
Springdale 1-5 (2)	638
West Lorain 1-6	545
Chambersburg 12 & 13 (2)	88
Gans 8 & 9 (2)	88
Forked River	86
Hunlock (2)	45
Buchanan	43
Other	59
Total Gas/Oil	**1,592**

	MW
Maryland Solar	20
Total Solar	**20**

Blue Creek	100
High Trail	99
Allegheny Ridge	80
N. Allegheny Ridge	70
Highland	62
Casselman	35
Meyersdale	30
Total Wind	**476**

Bath County	1,200
Regulated: 487 Competitive: 713 (2)	
Yards Creek (R)	210
Total Hydro	**1,410**

(1) Bay Shore 1 expected to be sold or deactivated by October 1, 2020. Sammis 1-4 expected to be deactivated by May 31, 2020.
(2) Pending sale of 1,572 MW expected to close third quarter 2017, subject to satisfaction of customary and other closing conditions including receipt of regulatory approvals and third party consent

Regulated Distribution

10 Operating Companies

6 States

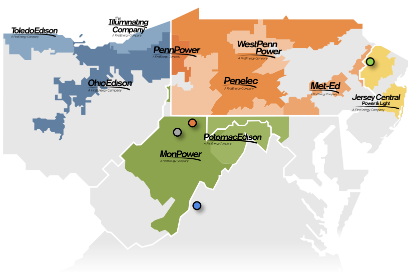
6M Customers

FIRSTENERGY

Unlocking Value for Investors

Regulated Distribution – Segment Overview

- **10 operating companies serving ~6 million customers across 6 states**
  - One of the largest contiguous service territories in the U.S.
  - Balanced customer sales mix of approximately 1/3 residential, 1/3 commercial, 1/3 industrial
  - Includes 3,790 MW of regulated generation; primarily serving West Virginia
- **~$9.6B of Total Revenues in 2016**
- **~$12.5B in Rate Base at YE 2015**



Regulated Distribution Companies

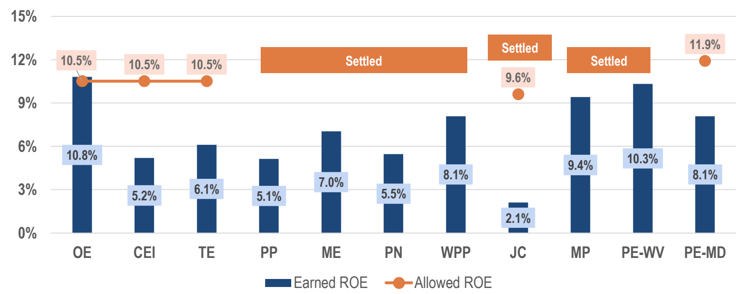
State	Operating Companies
Ohio	OE, CEI, TE
Pennsylvania	ME, PN[1], PP, WPP
New Jersey	JCP&L
West Virginia	MP, PE-WV
Maryland	PE-MD

Regulated Generating Plants

Plant	MW	Fuel Type
Harrison 1-3	1,984	Supercritical Coal
Fort Martin 1-2	1,098	Supercritical Coal
Bath County	487	Hydro
Yards Creek	210	Hydro
OVEC	11	Subcritical Coal
Total	**3,790**	

[1] Includes 4K customers in New York

Earned vs. Allowed Distribution ROEs



Impact of a 50 basis point change in Earned Distribution ROE on Annual Earnings Per Share										
OE	CEI	TE	PP	ME	PN	WPP	JC	MP	PE-WV	PE-MD
$0.01	<$0.01	<$0.01	<$0.01	$0.01	$0.01	<$0.01	$0.01	$0.01	<$0.01	<$0.01

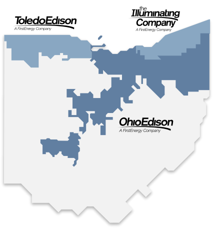
OH: SEET Filings (YE 2015)
PA: PA PUC Bureau of the Technical Utility Services Report (YE 2015)
NJ: ROE of 2.1% as of June 30, 2016. The NJBPU approved the Stipulation of Settlement ROE of 9.6% effective January 1, 2017.
WV: Source – WV/MD Rates; Quarterly reports filed with WV Commission (Q2 2016)
MD: Source – WV/MD Rates; Quarterly reports filed with MD Commission (Q2 2016)

Average Customer Bills

Rates Effective July 1, 2016

Average residential monthly usage in OH and NJ 750 kWh, all other states 1,000 kWh

Ohio Overview



Number of Customers

(000s)	Year-End 2016
OE	1,045
CEI	750
TE	310
	2,105

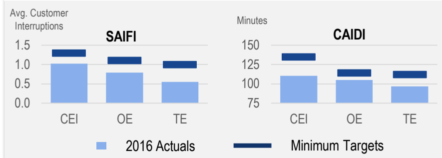
Principal Industries Served

Primary and Fabricated Metals, Automotive, Chemical, Plastic & Rubber, Petroleum

Rate Base and ROE Information

Company	Rates Effective	11/30/16 Rate Base	Allowed Debt / Equity	Allowed ROE
OE	January 2009	$1,464M	51% / 49%	10.5%
CEI	May 2009	$1,219M	51% / 49%	10.5%
TE	January 2009	$418M	51% / 49%	10.5%

2016 Reliability Information



Political Overview

Governor	Current Term
John Kasich (R)	Expires in 2019
Public Utilities Commission (PUCO)	Current Term
Asim Z. Haque, Chairman (I)	Expires in 2021
M. Beth Trombold, Vice Chair (I)	Expires in 2018
Lynn Slaby (R)	Expires in 2017
Thomas W. Johnson (R)	Expires in 2019

Recovery Mechanisms

Purchased Power / Fuel Rider	Storm Cost Recovery	Incremental Capital Recovery	Energy Efficiency	Smart Meter / Smart Grid	Alternative Energy
Annually	Base Rates	Quarterly	Semi Annually	Quarterly	Quarterly

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Pennsylvania Overview

Rate Base and ROE Information[(1)]

Company	Rates Effective	YE 2017 Rate Base	Filed Debt / Equity	Allowed ROE
PN	January 2017	$1,614M	47.4% / 52.6%	Settled
ME	January 2017	$1,386M	48.8% / 51.2%	Settled
PP	January 2017	$413M	49.9% / 50.1%	Settled
WPP	January 2017	$1,364M	49.7% / 50.3%	Settled

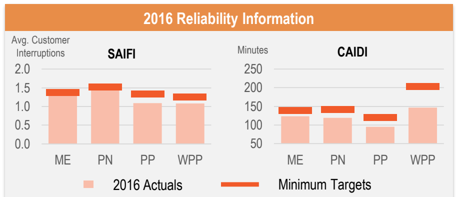
Number of Customers

(000s)	Year-End 2016
PN	588
ME	565
PP	165
WPP	724
	2,042

Principal Industries Served

Primary and Fabricated Metals, Coal Mining, Chemical, Plastic & Rubber, Non-Metallic Minerals

2016 Reliability Information



Political Overview

Governor	Current Term
Thomas W. Wolf (D)	Expires in 2019
PA Public Utility Commission (PAPUC)	Current Term
Gladys M. Brown, Chairman (D)	Expires in 2018
Andrew G. Place, Vice Chairman (D)	Expires in 2020
David W. Sweet (D)	Expires in 2021
John F. Coleman, Jr. (R)	Expires in 2017
Robert F. Powelson (R)	Expires in 2019

Recovery Mechanisms

Purchased Power / Fuel Rider	Storm Cost Recovery	Incremental Capital Recovery	Energy Efficiency	Smart Meter / Smart Grid	Alternative Energy
Quarterly	Base Rates	Quarterly	Annually	Annually	Annually

(1) Reflects filed rate base and debt/equity; final settlements/Orders do not specifically include rate base or capital structure

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New Jersey Overview

Number of Customers

(000s)	Year-End 2016
JCP&L	1,117

Principal Industries Served

Chemical, Primary and Fabricated Metals, Plastic & Rubber

Political Overview

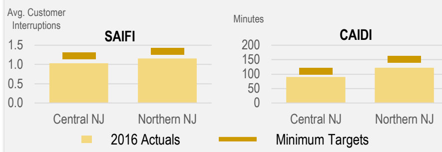
Governor	Current Term
Christopher J. Christie (R)	Expires in 2018

NJ Board of Public Utilities (BPU)	Current Term
President Richard S. Mroz (R)	Expires in 2021
Dianne Solomon (R)	Expires in 2018
Joseph L. Fiordaliso (D)	Expires in 2019
Upendra Chivukula (D)	Expires in 2020
Mary-Anna Holden (R)	Expires in 2017

Rate Base and ROE Information

Company	Rates Effective	Rate Base[1]	Allowed Debt / Equity	Allowed ROE
JCP&L	January 2017	$2,217M	55% / 45%	9.6%

2016 Reliability Information

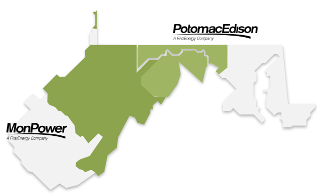


Recovery Mechanisms

Purchased Power / Fuel Rider	Storm Cost Recovery	Energy Efficiency	Alternative Energy
Annually	Base Rates / SRC Rider	Annually	Annually

[1] On December 12, 2016, the NJBPU approved the Stipulation of Settlement, which reflected rate base of $2,217M.

West Virginia/Maryland Overview



Number of Customers

(000s)	Year-End 2016
MP	390
PE	405
	795

Principal Industries Served

Chemical, Coal Mining, Non-Metallic Minerals, Primary and Fabricated Metals, Oil and Gas Extractions

Political Overview

Governor – West Virginia	Current Term
James C. Justice, Jr. (D)	Expires in 2021

Public Service Commission of WV (WV PSC)	Current Term
Michael A. Albert, Chairman (R)	Expires in 2019
Brooks F. McCabe (D)	Expires in 2021
Kara Cunningham Williams (D)	Expires in 2017

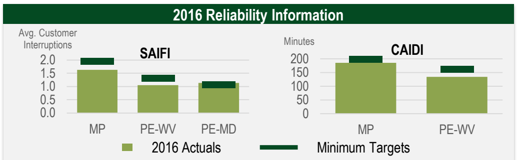
Governor – Maryland	Current Term
Lawrence J. Hogan (R)	Expires in 2019

MD Public Service Commission (PSC)	Current Term
W. Kevin Hughes, Chairman (D)	Expires in 2018
Harold D. Williams (D)	Expires in 2017
Michael T. Richard (R)	Expires in 2020
Jeanette M. Mills (R)	Expires in 2019
Anthony J. O'Donnell (R)	Expires in 2021

Rate Base and ROE Information

Company	Rates Effective	June 2016 Rate Base	Allowed Debt / Equity	Allowed ROE
MP	February 2015	$2,278M	53% / 47%	Settled
PE-WV	February 2015	$348M	48% / 52%	Settled
PE-MD	February 1993	$447M	48% / 52%	11.9%

2016 Reliability Information

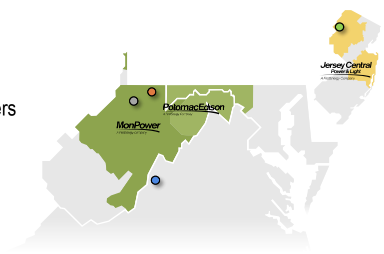


Recovery Mechanisms

State	Purchased Power / Fuel Rider	Storm Cost Recovery	Vegetation Management	Energy Efficiency
WV	Annually	Base Rates	Biennially	Annually
MD	Various	Base Rates	N/A	Annually

Regulated Generation Overview

- Regulated Distribution segment includes:
  - 3,580 MW of generation serving West Virginia customers owned and controlled by Mon Power
  - 210 MW of generation, which represents JCP&L's 50% ownership interest in Yards Creek



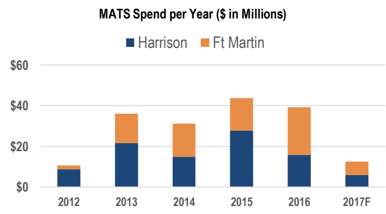
Plant	PJM Zone	State	Utility	Fuel Type	Units	Net Maximum Capacity (MW)	Year Plant Commissioned	2016 Output M MWH
Bath County	Rest of RTO	VA	MP	Hydro	6	487[1]	1985	0.5
Fort Martin	Rest of RTO	WV	MP	Coal	2	1,098	1967	6.8
Harrison	Rest of RTO	WV	MP	Coal	3	1,984	1972	12.9
OVEC	Rest of RTO	Multiple	MP	Coal	Multiple	11[2]		0.1
					Rest of RTO Total	**3,580**		
Yards Creek	EMAAC	NJ	JC	Hydro	3	210	1965	0.3
					EMAAC Total	**210**		
					Regulated Generation Total	**3,790**		**20.6**

[1] Represents MP's approximate 41% shareholder interest in AGC, which owns a 40% interest in Bath County, a pumped-storage hydroelectric station, operated by 60% owner Virginia Electric and Power Company (non-FE affiliated)
[2] Represents MP's 0.49% entitlement based on its participation in OVEC

Environmental Controls & MATS Spend
Regulated Generation

Environmental Controls	NDC	NOx Controls				SO_2 Controls		Particulate	Cooling Towers	Coal Sources
		SCR	SNCR	LNB	OFA	Scrubbers	Lo-S Fuel	Electro/Other		
Harrison 1-3	1,984	✓		✓		✓		✓	✓	NAPP
Fort Martin 1 & 2	1,098		✓	✓	✓	✓	✓	✓	✓	NAPP, Western, ILB
Sub-total	3,082									

Historical MATS Spend	Total compliance cost estimate of $177M; $161M spent through 12/31/2016
Fort Martin 1-2	GORE Mercury Control System, Duct Repairs, CEMS
Harrison 1-3	Precip Changes, FGD changes, SCR Catalyst, Duct Repairs, CEMS



Smart Meter Overview

Pennsylvania	2013 – 2016A	2017F	2018F	2019F
Meter Installations Approximately 2.1M	809k	500k	500k	300k
Costs $1.3B by 2032	Capital: $267M	Capital: $150M	Capital: $145M	Capital: $80M
	O&M: $148M	O&M: $45M	O&M: $35M	O&M: $35M
Customer Benefits $410M by 2032		$4.0	$9.0M	$15.5M

- Costs were initially recovered through an adjustable rider and are now collected in base rates with the option to reinstate the rider if costs exceed amounts recovered in distribution base rates or to recognize savings achieved
- The program successfully achieved automated billing for Penn Power in August 2016. This functionality is scheduled to be available for the remaining PA Operating Companies starting in March 2017

Other States

OH: FE filed a proposed Grid Modernization business plan with the Public Utilities Commission of Ohio in February 2016. The Commission has indicated that it intends to undertake a detailed policy review of grid modernization in Ohio and that they will address FE's plan after having conducted that review
MD: Maryland Public Service Commission initiated a proceeding in September 2016 to consider transforming Maryland's electric distribution system including maximizing benefits from Advanced Meter Infrastructure. An initial public conference was held December 8-9, 2016.

NJ: No current smart meter activity

WV: No current smart meter activity

Ohio Grid Modernization: Incremental Opportunity

In ESP IV, the Ohio companies agreed to empower customers through grid modernization initiatives, e.g., AMI, Distribution Automation, and VOLT/VAR Control

Estimates Included in Business Plan	Length	Total Estimated Costs
AMI Deployment	5 to 8 years	Capital: $2.2B - $3.5B
DA/VVC	8 to 15 years	O&M: $1.5B - $1.9B
		Total: $3.7B - $5.4B[1]

- **Business plan filed with PUCO includes three scenarios that provide the opportunity for significant investments over time:**
  - Full AMI deployment
  - Different levels of DA/VVC deployment
  - Net benefits to customers
- **Business plan is subject to PUCO review and approval**

[1] Not included in current finance plan

Rate Strategy

State	Last Base Rate Change	Examples of Riders	Key Activity
Ohio	2009	**Distribution Capital Recovery:** annual cap increases of • $30M June 1, 2016 to May 31, 2019 • $20M June 1, 2019 to May 31, 2022 • $15M June 1, 2022 to May 31, 2024 **Demand Side Management and Energy Efficiency Rider:** Recovers all program costs, including lost distribution revenues **Distribution Modernization Rider:** Recovers $204M annually for three years beginning in 2017, with an opportunity to extend for two additional years	• April 3, 2017: File a plan to consider transition to proposed straight fixed variable cost recovery mechanism for residential customers to be phased in over three year period beginning January 1, 2019 • 2020-2021: Potential extension of DMR • June 2024: Base rate freeze ends and Companies are required to file a base rate case • Smart Grid deployment
Pennsylvania	2017	**Distribution System Improvement Charge Rider:** Rider was set to zero when new rates were implemented on January 27, 2017. When costs exceed the amount recovered in base rates the rider will restart. **Smart Meter Technologies Charge Rider:** Rider was set to zero when new rates were implemented on January 27, 2017. When costs exceed the amount recovered in base rates the rider will restart. Rider will restart to recognize savings achieved	• January 27, 2017 base rate increase effective • January 27, 2019: Earliest date for base rate filing
New Jersey	2017		• January 1, 2017, base rate increase effective • State Senate investigating revenue decoupling
West Virginia / Maryland	WV 2015 / MD 1994	**WV Vegetation Management Surcharge:** Recovers costs associated with right-of-way tree trimming programs	• WV - The RFP for generation shortfall was issued on December 16, 2016 and bids received in February 2017 • MD – No plans for future rate case

Recovery mechanisms provide revenue between base rate cases

Regulated Transmission

24,200+
Line Miles

~9%
Formula Companies' Rate Base Growth 2016-2021

$0.8B-$1.2B
Average annual capital expenditures through 2021

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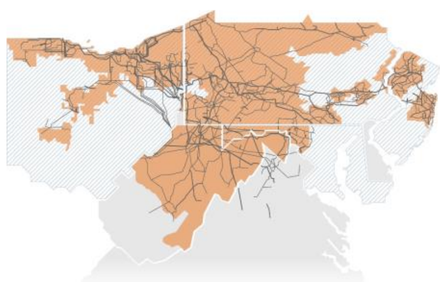
Unlocking Value for Investors

Regulated Transmission – Segment Overview

- **One of the largest transmission systems in PJM with 24,200+ miles**
  - Includes FERC-regulated transmission assets recovered through formula rates owned by ATSI, TrAIL, MAIT[1], and JCP&L*
  - Includes FERC-regulated transmission assets recovered through stated rates owned by MP, PE, and WPP
- **~$1B of Total Revenues in 2016**



Transmission Operating Companies

Company	Rate Structure
ATSI	Forward-Looking
TrAIL	Forward-Looking
MAIT*	Forward-Looking
JCP&L*	Forward-Looking
Utility (WPP, MP, PE)	Stated Rate

[1] Filed for Formula Rates with FERC on October 28, 2016

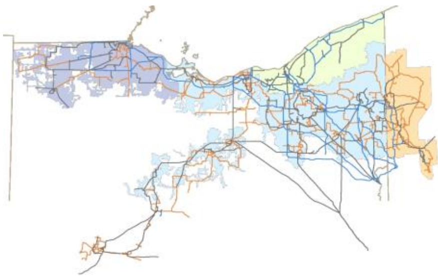
Federal Energy Regulatory Commission (FERC)

	Current Term
Cheryl A. LaFleur (D) – Acting Chair	Expires in 2019
Colette D. Honorable (D)	Expires in 2017

Qualifications: Composed of up to five commissioners who are appointed by the President of the United States with the advice and consent of the Senate. Commissioners serve five-year terms and have an equal vote on regulatory matters.

ATSI Overview

ATSI®
American Transmission Systems, Inc.
a subsidiary of FirstEnergy Corp.



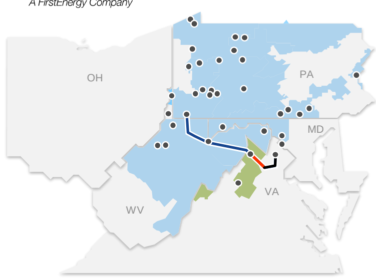
Jurisdiction	FERC
Test Year	Forward-Looking
Term	January – December
Filing Month	October
Allowed ROE	10.38%
Rate Base	$2.4B[1]
Cap Structure	40% Debt / 60% Equity
Location	OE, PP, CEI, and TE
True-Up Mechanism	Yes

[1] Represents projected average rate base from its 2017 Projected Transmission Revenue Requirement filing for the period January 1, 2017, through December 31, 2017

- 69 kV
- 138 kV
- 345 kV
- Ohio Edison
- Penn Power
- The Illuminating Company
- Toledo Edison

TrAILCo Overview

TrAILCo™
A FirstEnergy Company



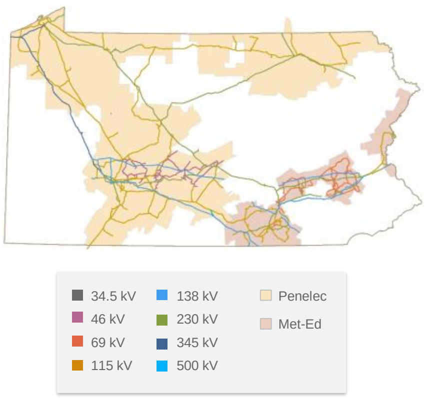
- FirstEnergy Utility Service Area
- FirstEnergy VA Transmission Zone
- TrAIL 500 kV Line
- Substation
- FE TrAIL 50% Joint Ownership with Dominion Resources
- Dominion Resources Owned

Jurisdiction	FERC
Test Year	Forward-Looking
Term	June – Following May
Filing Month	May
Allowed ROE	12.7% (TrAIL the Line & Black Oak SVC) 11.7% (All other projects)
Rate Base	$1.5B[1]
Cap Structure	40% Debt / 60% Equity
Location	WPP, MP, and PE as well as some portions of ME and PN
True-Up Mechanism	Yes

[1] Represents projected average rate base from its 2016 Formula Rate Annual updated filing for the period June 1, 2016, through May 31, 2017

MAIT Overview

MAIT
Mid-Atlantic Interstate Transmission, LLC
A FirstEnergy Company

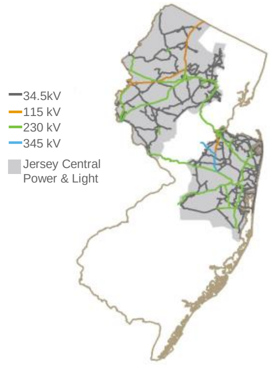


Jurisdiction	FERC
Test Year	Forward-Looking
Term	January – December
Filing Month	October
Requested ROE	11%
Rate Base	$538M[1]
Hypothetical Cap Structure	50% Debt / 50% Equity
Location	ME, PN
True-Up Mechanism	Yes

[1] Represents annual projected average rate base from its 2017 Projected Transmission Revenue Requirement filing for the period January 1, 2017, through December 31, 2017

Filed for formula rates with the FERC on October 28, 2016, in Docket Nos. ER17-214-000 and ER17-216-000.; ME and PN completed asset transfer to MAIT on January 31, 2017. Until FERC sets an effective date for the formula rate, the stated rate will remain in effect.

JCP&L Transmission Overview

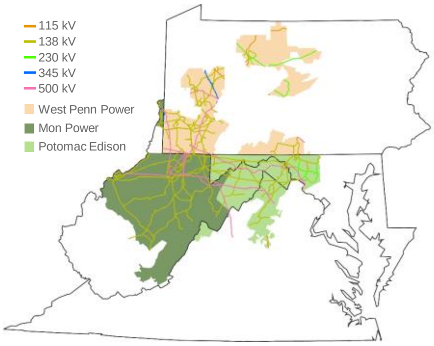


Jurisdiction	FERC
Test Year	Forward-Looking
Term	January - December
Filing Month	October
Requested ROE	11%
Rate Base*	$748M[1]
Cap Structure	60% Debt / 40% Equity
Location	JCP&L
True-Up Mechanism	Yes

[1] Represents annual projected average rate base from its 2017 Projected Transmission Revenue Requirement filing for the period January 1, 2017, through December 31, 2017

Filed for formula rates with the FERC on October 28, 2016, in Docket No. ER17-217-000 ; until the FERC sets an effective date for the formula rate, the stated rate will remain in effect

Utility Transmission Overview

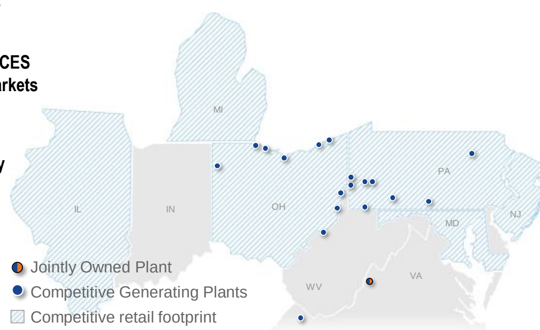


Jurisdiction	FERC
Test Year	Stated Rate
Location	WPP, MP, PE

- **Capital spend is supported by the revenues received from the stated rates**
- **FERC regulations require utilities to provide open access transmission service at FERC-approved rates, terms and conditions**
- **Transmission facilities are subject to functional control by PJM**

CES Segment Overview

- **Currently undergoing strategic review of the CES Segment; with a target to exit competitive markets by mid-2018**
- **Segment primarily comprised of three legal entities: FirstEnergy Solutions, Allegheny Energy Supply and FENOC**
  - FES buys all output of AE Supply
- **Diverse portfolio of 13,162[1] MW**
- **2016 revenues of $4.5B**
- **2016 generation output of 65M MWH**



Generation Portfolio

Fuel Type	MW	%
Supercritical Coal	4,990	38%
Nuclear	4,048	31%
Gas / Oil	1,592	12%
Subcritical Coal	1,323	10%
Hydro	713	5%
Wind / Solar	496	4%
Total	**13,162**	

Business Strategy

- Treat as standalone business, focusing on predictable cash flows and minimizing overall business risk
- Effectively hedge generation with long generation vs. sales strategy
- Strong focus on cost management to maintain positive Free Cash Flow

[1] Includes 1,572 MW of AE Supply assets; sale pending

CES Segment Structure

FE Corp.

FES Consolidated

Debt[1] in $ Millions	FES (Parent)	FG	NG	FES Cons.
Short-Term Debt	$101	-	-	$101
Long-Term - Unsecured	$696	$835	$842	$2,373
Long-Term – Secured (FMB)	-	$338	$284	$622
Long-Term – Secured (BV2 Sale-Leaseback)			$5	$5
Total Long-Term Debt	$696	$1,173	$1,131	$3,000
Undrawn Revolver Capacity[2]	$500			
Sale-Leaseback[3]	~$0.9B			
Net PP&E		~$0.7B	~$0.9B	~$1.6B
Capacity	10,180 MW			

AE Supply Consolidated

Debt[1] in $ Millions	AE Supply	AGC	AE Supply Cons.
Short-Term Debt	$0	$24	$24
Long-Term - Unsecured	$306	$100	$406
Long-Term - Secured	$215	-	$215
Total Long-Term Debt	$521	$100	$621
Undrawn Revolver Capacity	$-		
Sale-Leaseback	$-		
Net PP&E	~$0.9B	~$0.4B	~$1.3B
Capacity[4]	2,982 MW		

- Cross-guarantees on debt exist between FES, FG and NG
- No cross guarantees on debt in place between FES and AE Supply
- FES, AE Supply and FENOC primarily comprise the Competitive Energy Services segment, however, the segment also includes other FirstEnergy subsidiaries

[1] Long-Term debt numbers represent principle amount outstanding. Discounts/premiums, unamortized issuance costs, purchase accounting and capital leases are excluded.
[2] FE Corp Revolving Credit Facility is secured by FG and NG FMB. An additional $200M of surety credit support under the facility is not reflected on this table.
[3] Represents net present value of future lease payments for the Bruce Mansfield Unit 1 sale-leaseback arrangement
[4] Pending sale of 1,572 MW expected to close third quarter 2017, subject to satisfaction of customary and other closing conditions including receipt of regulatory approvals and third party consent

CES Competitive Generation Portfolio

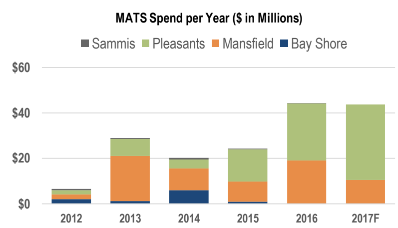
Plant Name	PJM Zone	FE Entity	State	Fuel Type	Units	Net Maximum Capacity (MW)	Year Plant Commissioned	2016 Output M MWH
Bay Shore [1]	ATSI	FES (FG)	OH	Coal, Oil	2	153	1955	1.0
Davis-Besse	ATSI	FES (NG)	OH	Nuclear	1	908	1977	6.4
Eastlake	ATSI	FES (FG)	OH	Oil	1	29	1972	<0.1
Mansfield	ATSI	FES (FG)	PA	Coal	3	2,490	1976	11.6
Perry	ATSI	FES (NG)	OH	Nuclear	1	1,268	1987	10.4
Sammis [1]	ATSI	FES (FG)	OH	Coal, Oil	8	2,223	1959	8.1
West Lorain	ATSI	FES (FG)	OH	Natural Gas, Oil	2	545	1973	0
				Total ATSI Zone Generation		7,616		
Forked River [3]	EMAAC	FES	NJ	Natural Gas	1	86		<0.1
				Total EMAAC Zone Generation		86		
Hunlock [2]	MAAC	AES	PA	Natural Gas	1	45	2000	<0.1
Wind Farms [3]	MAAC	FES	Multiple	Wind	Multiple	277		0.9
				Total MAAC Zone Generation		322		
Bath County [2]	Rest of RTO	AES	VA	Hydro	6	713 [4]	1985	0.7
Beaver Valley	Rest of RTO	FES (NG)	PA	Nuclear	2	1,872	1976	15.2
Buchanan	Rest of RTO	AES	VA	Natural Gas	1	43	2002	0.2
Chambersburg [2]	Rest of RTO	AES	PA	Natural Gas	1	88	2001	0.2
Gans [2]	Rest of RTO	AES	PA	Natural Gas	1	88	2000	<0.1
Maryland Solar [3]	Rest of RTO	FES	MD	Solar	Multiple	20		<0.1
OVEC [1]	Rest of RTO	FES/AES	Multiple	Coal	Multiple	177 [5]		0.8
Pleasants	Rest of RTO	AES	WV	Coal	2	1,300	1979	6.9
Springdale [2]	Rest of RTO	AES	PA	Natural Gas	5	638	1999	4.5
Wind Farms [3]	Rest of RTO	FES	Multiple	Wind	Multiple	199		0.3
				Total Rest of RTO Generation		5,138		
				Total Competitive Generation		13,162		67.3

[1] Bay Shore 1 expected to be sold or deactivated by October 1, 2020. Sammis 1-4 expected to be deactivated by May 31, 2020.
[2] Pending sale of 1,572 MW expected to close third quarter 2017, subject to satisfaction of customary and other closing conditions including receipt of regulatory approvals and third party consent
[3] Long-term PPA
[4] Represents AE Supply entitlement
[5] Represents FES' 4.85% and AE Supply's 3.01% entitlement

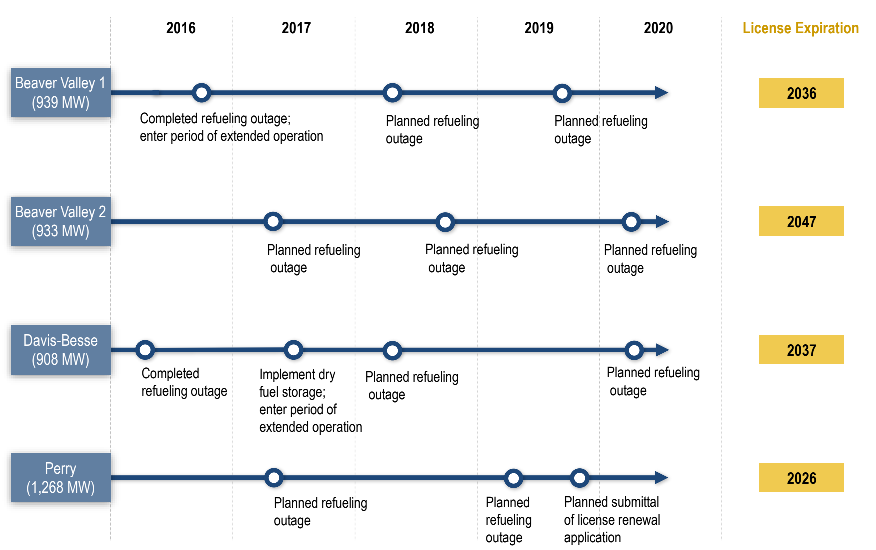
Fossil Environmental Controls and MATS Spend

	Environmental Controls	NDC	NOx Controls					SO_2 Controls	Particulate		Cooling Towers	Coal Sources
			SCR	SNCR	COS	LNB	OFA	Scrubbers	Baghouse	Electro/Other		
Supercritical	Mansfield 1-3	2,490	✓		✓	✓	✓	✓		✓	✓	NAPP
	Pleasants 1-2	1,300	✓			✓		✓		✓	✓	NAPP
	Sammis 6 & 7	1,200	✓		✓	✓	✓	✓		✓		NAPP, Western
	Sub-total	4,990										
Subcritical	Sammis 1 - 4	720		✓	✓	✓	✓	✓	✓			NAPP, Western
	Sammis 5	290		✓	✓	✓	✓	✓		✓		NAPP, Western
	Bay Shore 1	136				CFB		CFB	✓			Petcoke
	Sub-total	1,146										

Historical MATS Spend	Total compliance cost estimate of $168M; $124M spent through 12/31/2016
Mansfield 1-3	WFGD Changes, SCR Changes, CEMS
Pleasants 1-2	Precip Changes, FGD Changes, SCR Catalyst, Duct Repairs, CEMS
Bay Shore 1	Baghouse Fabric Filter changes, Mini ACI system, CEMS
Sammis 1-7	Precip Controls, CEMS



Nuclear Timeline



Acronyms and Definitions

ACI	Activated Carbon Injection
AMI	Advanced Metering Infrastructure
BR	Base Residual Auction
CAIDI	Customer Average Interruption Duration Index
CEMS	Continuous Emissions Monitoring System
COS	Combustion Optimization System
CFB	Circulating Fluidized Bed Boiler is inherently low emitting for NOx and SO_2
DA	Distribution Automation
EMAAC	EMAAC Locational Deliverability Area in PJM
ILB	Illinois Basin
kV	Kilovolt
kWh	Kilowatt-hour
LNB	Low NOx Burners
Lo-S	Low Sulfur Coal
MAAC	MAAC Locational Deliverability Area in PJM
MATS	Mercury and Air Toxics Standards
MMBTU	M British Thermal Unit
MW	Megawatt
MWH	Megawatt-hour
NAPP	Northern Appalachian Coal
NDC	Net Demonstrated Capacity
NOX	Nitrogen Oxide
OFA	Separated Overfire Air
OVEC	Ohio Valley Electric Corporation
PJM	PJM Interconnection, L.L.C.
PPA	Purchase Power Agreement
Precip	Electrostatic Precipitator
ROE	Return on Equity
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
SAIFI	System Average Interruption Frequency Index
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
SO2	Sulfur Dioxide
SVC	Static VAR Compensator
WFGD	Wet Flue Gas Desulfurization
VVC	Volt/Var Control

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