

Earnings Conference Call 4th Quarter 2017

February 7, 2018



Cautionary Statements Regarding Forward-Looking Information

This presentation contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by Exelon Corporation, Exelon Generation Company, LLC, Commonwealth Edison Company, PECO Energy Company, Baltimore Gas and Electric Company, Pepco Holdings LLC, Potomac Electric Power Company, Delmarva Power & Light Company, and Atlantic City Electric Company (Registrants) include those factors discussed herein, as well as the items discussed in (1) Exelon's 2016 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 24, Commitments and Contingencies; (2) Exelon's Third Quarter 2017 Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors; (b) Part 1, Financial Information, ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 18; and (2) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this press release. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this presentation.

Non-GAAP Financial Measures

Exelon reports its financial results in accordance with accounting principles generally accepted in the United States (GAAP). Exelon supplements the reporting of financial information determined in accordance with GAAP with certain non-GAAP financial measures, including:

- **Adjusted operating earnings** exclude certain costs, expenses, gains and losses and other specified items, including mark-to-market adjustments from economic hedging activities, unrealized gains and losses from nuclear decommissioning trust fund investments, merger and integration related costs, impairments of certain long-lived assets, certain amounts associated with plant retirements and divestitures, costs related to a cost management program and other items as set forth in the reconciliation in the Appendix
- **Adjusted operating and maintenance expense** excludes regulatory operating and maintenance costs for the utility businesses and direct cost of sales for certain Constellation and Power businesses, decommissioning costs that do not affect profit and loss, the impact from operating and maintenance expense related to variable interest entities at Generation, EDF's ownership of O&M expenses, and other items as set forth in the reconciliation in the Appendix
- **Total gross margin** is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners, JExel Nuclear JV, variable interest entities, and net of direct cost of sales for certain Constellation and Power businesses
- **Adjusted cash flow from operations** primarily includes net cash flows from operating activities and net cash flows from investing activities excluding capital expenditures, net merger and acquisitions, and equity investments
- **Free cash flow** primarily includes net cash flows from operating activities and net cash flows from investing activities excluding certain capital expenditures, net merger and acquisitions, and equity investments
- **Operating ROE** is calculated using operating net income divided by average equity for the period. The operating income reflects all lines of business for the utility business (Electric Distribution, Gas Distribution, Transmission).
- **EBITDA** is defined as earnings before interest, taxes, depreciation and amortization. Includes nuclear fuel amortization expense.
- **Revenue net of purchased power and fuel expense** is calculated as the GAAP measure of operating revenue less the GAAP measure of purchased power and fuel expense

Due to the forward-looking nature of some forecasted non-GAAP measures, information to reconcile the forecasted adjusted (non-GAAP) measures to the most directly comparable GAAP measure may not be currently available, as management is unable to project all of these items for future periods

Non-GAAP Financial Measures Continued

This information is intended to enhance an investor's overall understanding of period over period financial results and provide an indication of Exelon's baseline operating performance by excluding items that are considered by management to be not directly related to the ongoing operations of the business. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets and planning and forecasting of future periods.

These non-GAAP financial measures are not a presentation defined under GAAP and may not be comparable to other companies' presentation. Exelon has provided these non-GAAP financial measures as supplemental information and in addition to the financial measures that are calculated and presented in accordance with GAAP. These non-GAAP measures should not be deemed more useful than, a substitute for, or an alternative to the most comparable GAAP measures provided in the materials presented.

Non-GAAP financial measures are identified by the phrase "non-GAAP" or an asterisk. Reconciliations of these non-GAAP measures to the most comparable GAAP measures are provided in the appendices and attachments to this presentation, except for the reconciliation for total gross margin, which appears on slide 54 of this presentation.

Milestones and Accomplishments

Financial

- Delivered FY 2017 GAAP earnings per share of \$3.97 and adjusted operating earnings per share* of \$2.60, within our guidance range
- Updated dividend policy to 5% growth annually through 2020
- Tax reform legislation will benefit our utility customers through lower bills after committed rate adjustments while our shareholders benefit from additional utility rate base growth and lower tax rates at ExGen
- Expanded cost management program from 3rd quarter 2017 will save an incremental \$250M annually by 2020
- Effective capital deployment at ExGen:
 - Creation of Renewables JV with Hancock
 - ExGen Renewables IV project financing
 - Exit of EGTP portfolio

Operational

- Utilities performed largely at first quartile levels with especially strong results across key metrics:
 - BGE, ComEd and PECO achieved 1st decile performance in the System Average Interruption Frequency Index (SAIFI)
 - BGE and ComEd achieved 1st decile performance in the Customer Average Interruption Duration Index (CAIDI)
 - PHI achieved best ever performance on SAIFI and CAIDI
- Invested \$5.3B of capital into our utilities to improve reliability, replace aging infrastructure, and enhance customer experience
- Total Exelon utilities collectively earned 9.5% ROE in 2017, the mid-point of our long-term range
- Achieved 94.1%⁽¹⁾ nuclear capacity factor, producing a record 157 TWhs of nuclear generation

Regulatory & Policy

- Successful dismissal of legal challenges of NY and IL ZEC programs in federal district court; appeals process is ongoing
- FERC recognized need to better understand the status of resilience of system. Created “Grid Resilience in Regional Transmission Organizations and Independent System Operators” order to seek input from RTOs on how market rules may need to be changed
- Completed distribution rate cases providing \$283M in revenue increases and another \$114M of rate increases for FERC transmission assets

Employees & Community

- 2017 awards and recognitions include: Billion Dollar Roundtable, Civic 50, Top 50 Companies for Diversity, Best Places to Work in 2017, CEO Action for Diversity & Inclusion, and UN’s HeForShe
- Exelon and our employees set a new record in corporate philanthropy and volunteerism, committing over \$52M in giving and volunteering 210,000 hours
- Recognized by Dow Jones Sustainability Index for 12th consecutive year and by NewsWeek Green rankings for 9th consecutive year
- 2,200 employees, contractors and support personnel from Exelon’s six utilities mobilized to assist residents in the southeastern U.S. impacted by Hurricane Irma

(1) Capacity factor excludes impacts of Salem

Proven Track Record of Improving Operational Performance

Operations	Metric	At CEG Merger (2012)			2015	Q4 2017			
		BGE	ComEd	PECO	PHI	BGE	ComEd	PECO	PHI
Electric Operations	OSHA Recordable Rate								
	2.5 Beta SAIFI (Outage Frequency)								
	2.5 Beta CAIDI (Outage Duration)								
Customer Operations	Customer Satisfaction				N/A				
	Service Level % of Calls Answered in <30 sec								
	Abandon Rate								
Gas Operations	Percent of Calls Responded to in <1 Hour		No Gas Operations				No Gas Operations		
Overall Rank	Electric Utility Panel of 24 Utilities ⁽¹⁾	23 rd	2 nd	2 nd	18 th	Performance Quartiles			
						Q1	Q2	Q3	Q4

- Best on record SAIFI and CAIDI performance for BGE, ComEd and PHI
- Best on record Customer Satisfaction performance for BGE, ComEd and PECO
- BGE, ComEd and PECO achieved 1st decile performance in SAIFI
- BGE and ComEd achieved 1st decile performance in CAIDI
- For the 5th consecutive year, BGE and PECO achieved top decile performance in Gas Odor Response. PHI improved by moving from 1st quartile in 2016 to top decile in 2017.

(1) Ranking based on results of five key industry performance indicators – CAIDI, SAIFI, Safety, Customer Satisfaction, and Cost per Customer

Best in Class at ExGen and Constellation

Exelon Generation Operational Metrics

- Continued best in class performance across our Nuclear fleet:
 - Capacity factor for Exelon owned and operated units was 94.1%⁽¹⁾
 - This was the second consecutive year over 94% and the fourth out of the last five years topping 94%
 - Most nuclear power ever generated at 157 TWhs⁽²⁾
 - 2017 average refueling outage duration of 23 days, just over the Exelon record of 22 days set in 2016
- Strong performance across our Fossil and Renewable fleet:
 - Renewables energy capture: 95.8%
 - Power dispatch match: 98.8%

Constellation Metrics

74% retail power customer renewal rate

24% power new customer win rate

90% natural gas customer retention rate

25 month average power contract term

Average customer duration of more than 5 years

Stable Retail Margins

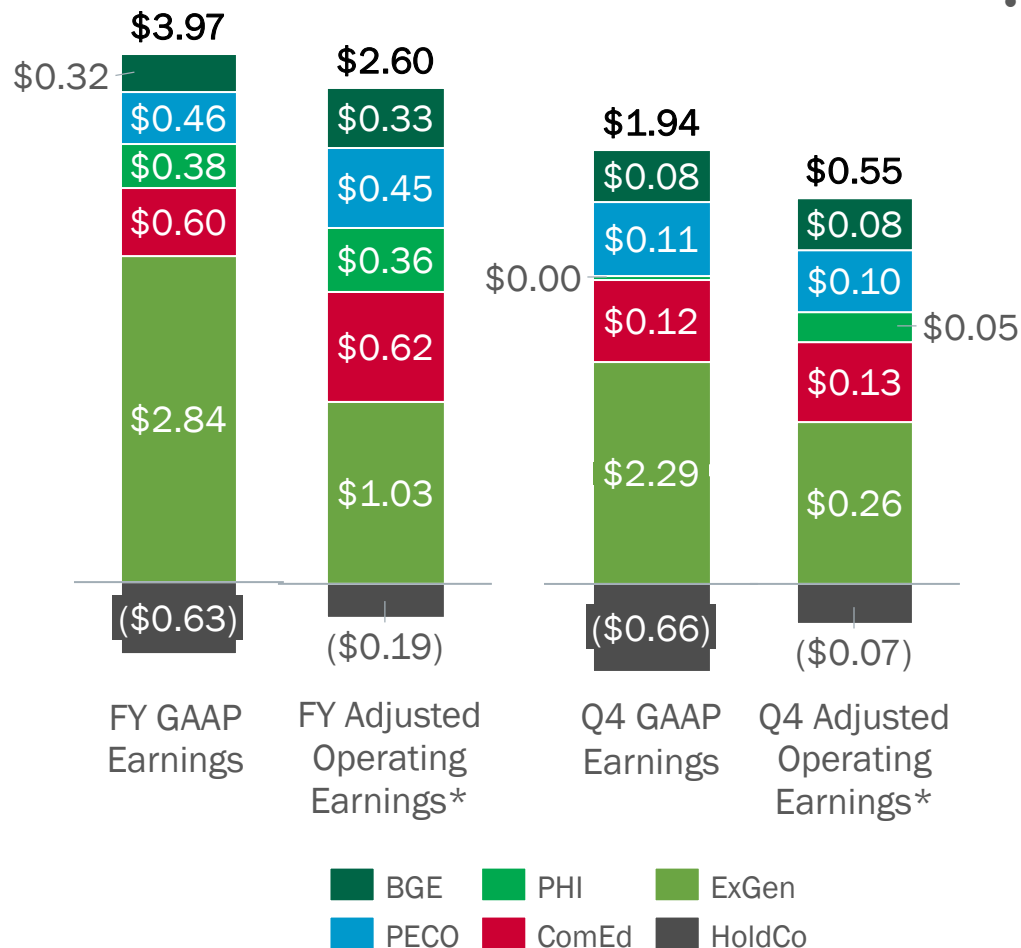
Note: Statistics represent full year 2017 results

(1) 2017 capacity factor includes FitzPatrick for the Exelon period of ownership and operation (March 31 to December 31, 2017) and excludes impacts of Salem

(2) Reflects generation output at ownership

2017 Financial Results

2017 EPS Results⁽¹⁾



- Adjusted (non-GAAP) operating earnings* full year drivers versus \$2.55 - \$2.75 guidance:

Utilities

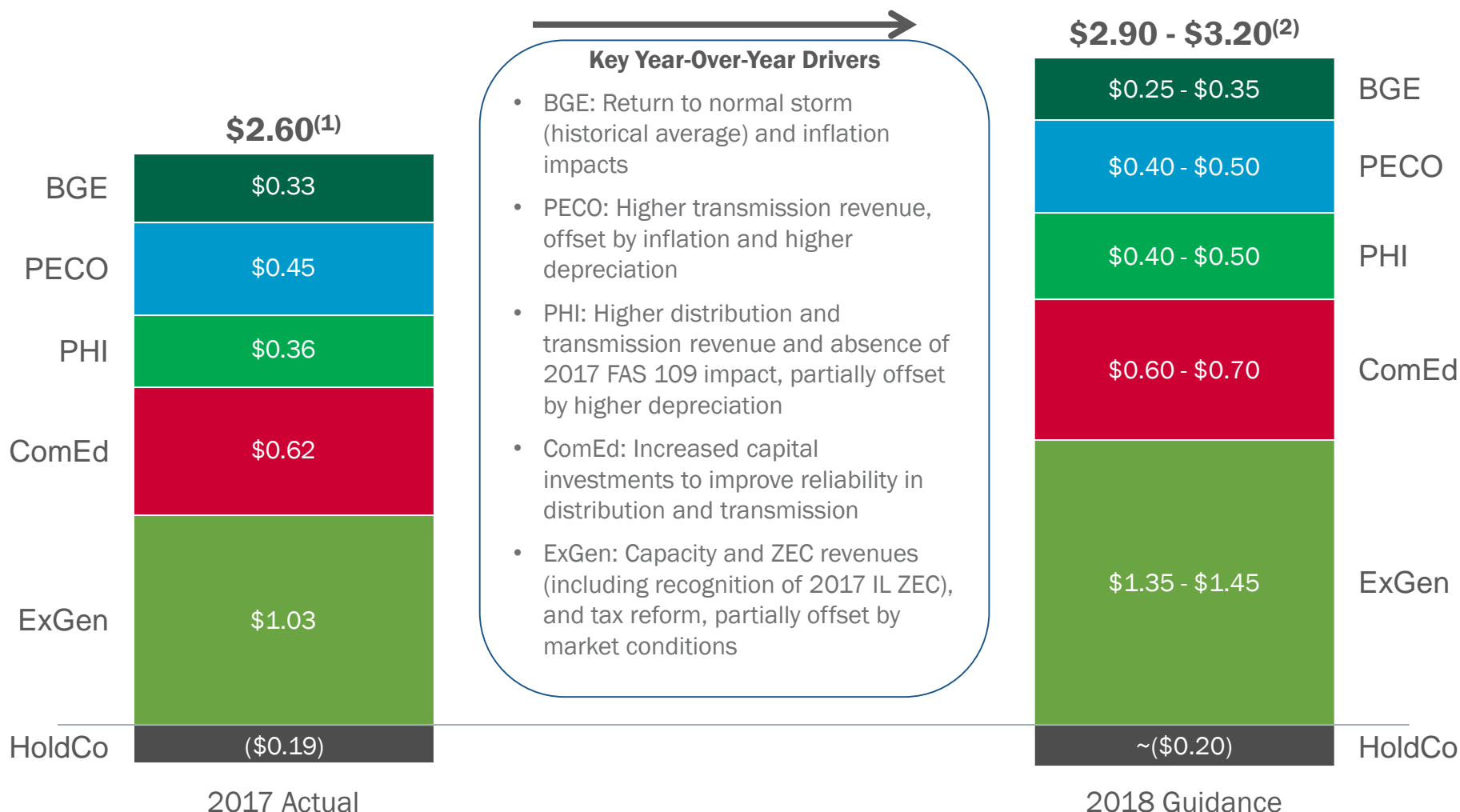
- ↑ Reduced storm activity
- ↑ Lower O&M
- ↓ FAS 109 Reg. Asset Impairment

Exelon Generation

- ↓ IL ZEC Timing

(1) Amounts may not add due to rounding

2018 Adjusted Operating Earnings* Guidance



Expect Q1 2018 Adjusted Operating Earnings* of \$0.90 - \$1.00 per share

Note: Amounts may not add due to rounding

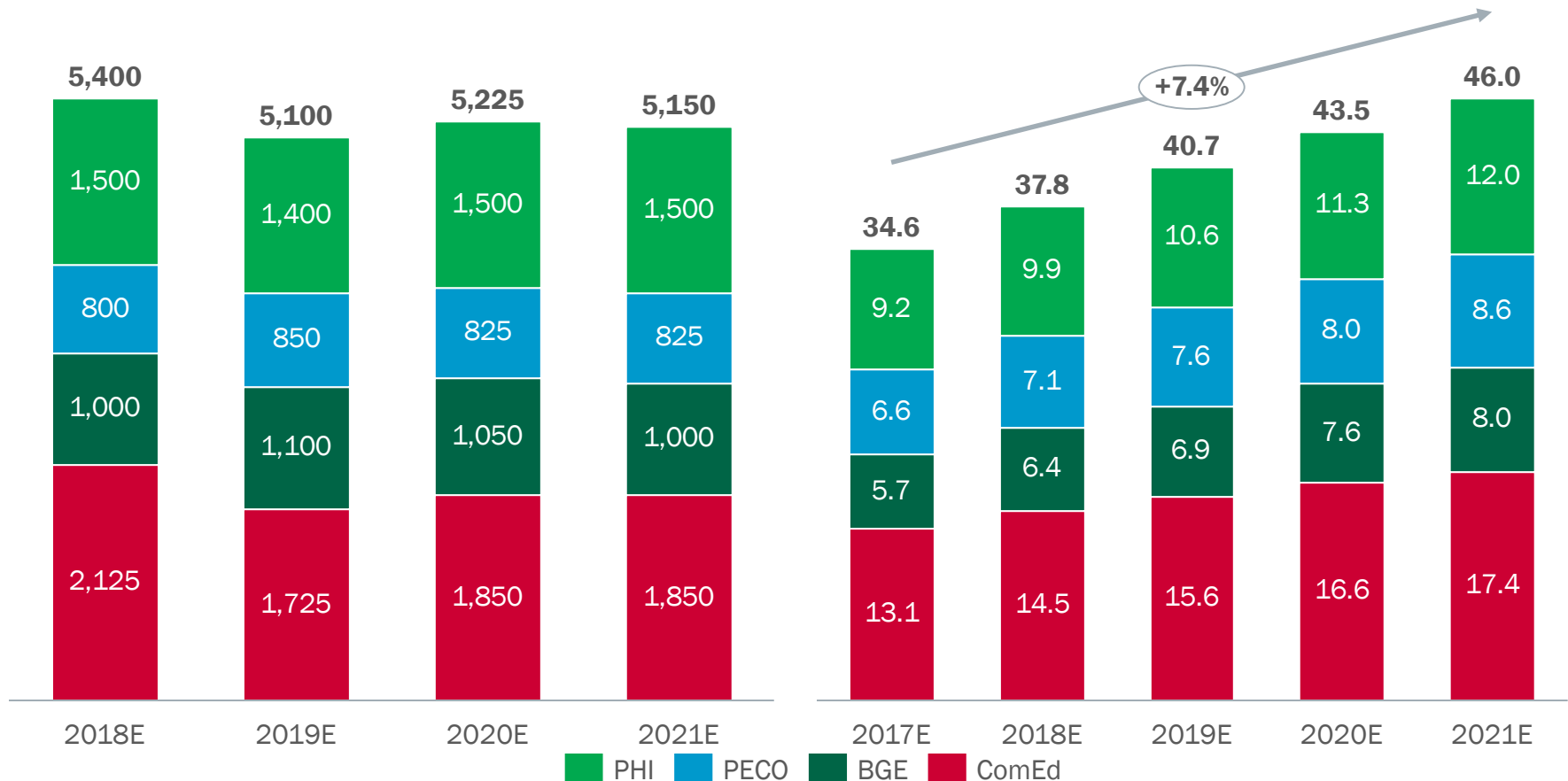
(1) 2017 results based on 2017 average outstanding shares of 949M

(2) 2018 earnings guidance based on expected average outstanding shares of 969M

Our Capital Plan Drives Leading Rate Base Growth

Capital Expenditures (\$M)

Rate Base (\$B)⁽¹⁾



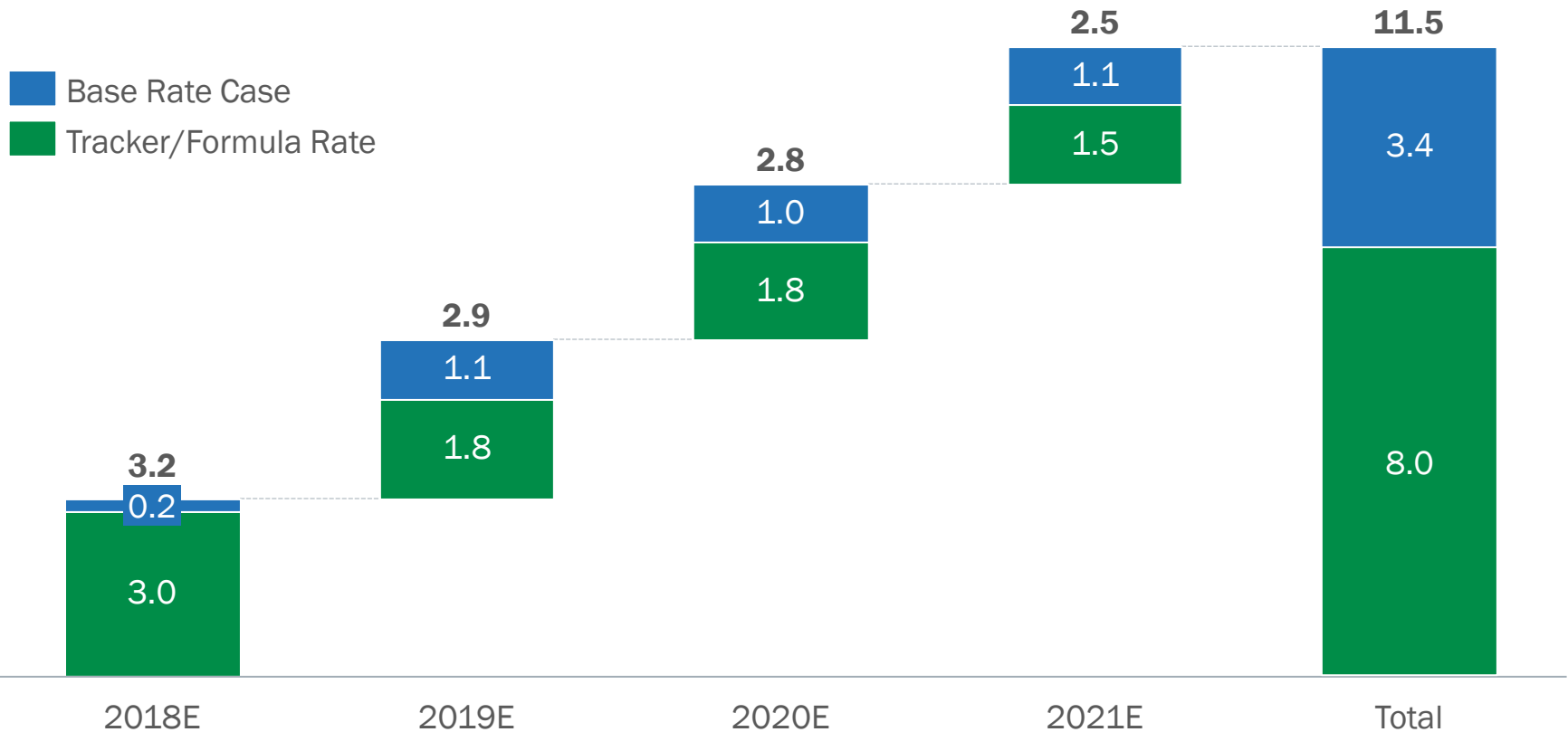
\$21B of capital will be invested at Exelon utilities from 2018-2021 for grid modernization and customer satisfaction

Note: CapEx numbers are rounded to nearest \$25M and numbers may not add due to rounding

(1) Rate base reflects year-end estimates

Mechanisms Cover Bulk of Rate Base Growth

Rate Base Growth Breakout 2018-2021 (\$B)



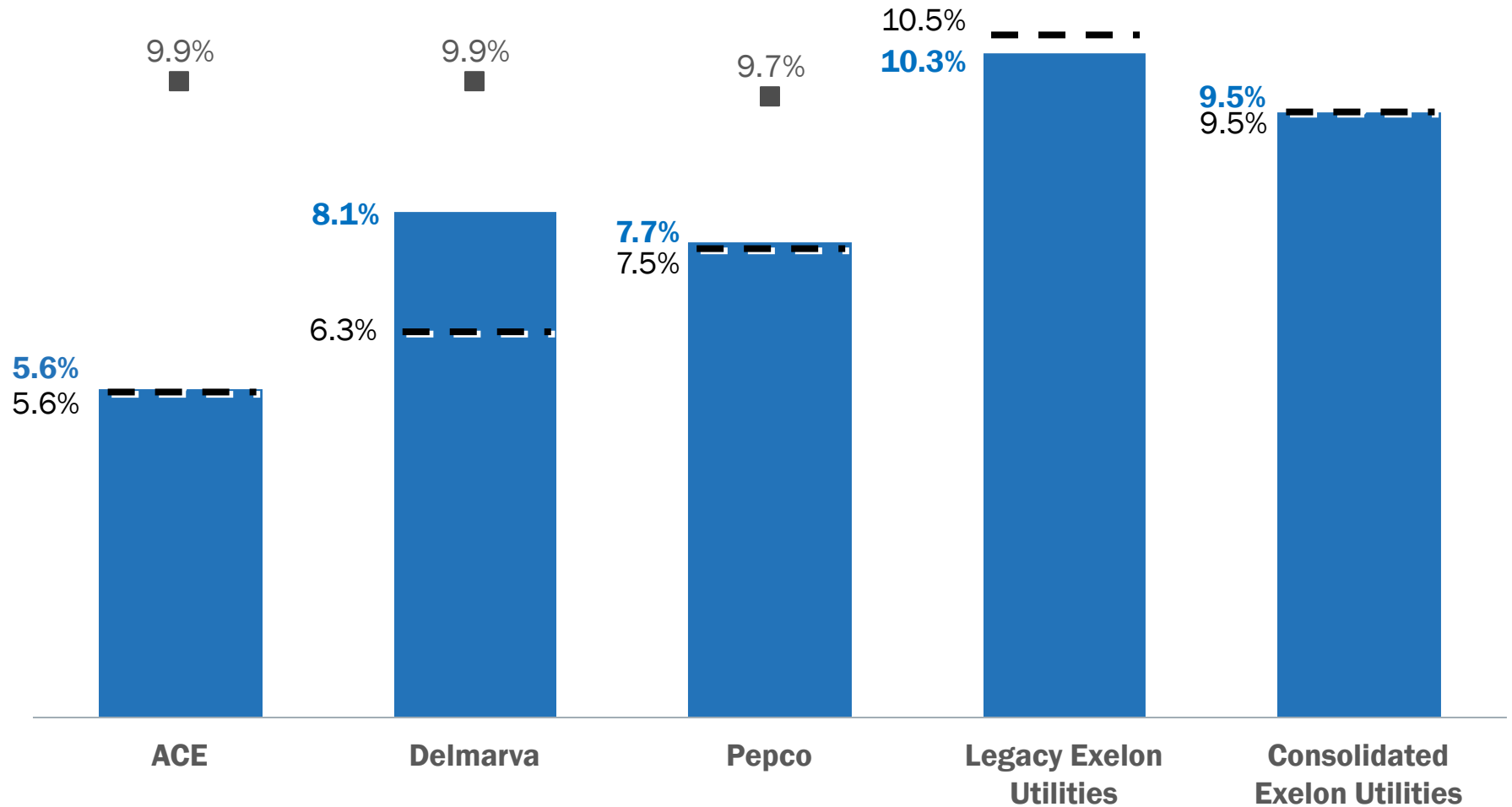
Of the approximately \$11.5 billion of rate base growth Exelon Utilities forecasts over the next 4 years, ~70% will be recovered through existing formula and tracker mechanisms

Note: Numbers may not add due to rounding

Trailing 12 Month ROEs* vs Allowed ROE

Twelve Month Trailing Earned ROEs*

■ Allowed ROE* — Q4 2016 ■ Q4 2017



Note: Represents the 12-month periods ending 12/31/2016 and 12/31/2017, respectively. ROEs* represent weighted average across all lines of business (Electric Distribution, Gas Distribution, and Transmission).

Exelon Utilities' Distribution Rate Case Updates

ACE NJ Order

Authorized Revenue Requirement Increase ⁽¹⁾	\$43.0M
Authorized ROE	9.60%
Common Equity Ratio	50.47%
Order Received	9/22/17

Pepco MD Order

Authorized Revenue Requirement Increase ⁽¹⁾	\$32.4M
Authorized ROE	9.50%
Common Equity Ratio	50.15%
Order Received	10/20/17

ComEd Filing

Authorized Revenue Requirement Increase ⁽¹⁾	\$95.6M
Authorized ROE	8.40%
Common Equity Ratio	45.89%
Order Received	12/6/17

Delmarva MD Filing

Per Settlement Revenue Requirement Increase ⁽¹⁾	\$13.4M
Per Settlement ROE	9.50% ⁽³⁾
Per Settlement Common Equity Ratio	N/A
Order Expected	2/9/18

Delmarva DE Electric Filing

Requested Revenue Requirement Increase ^(1,2)	\$31.2M
Requested ROE	10.10%
Requested Common Equity Ratio	50.52%
Order Expected	Q3 2018

Delmarva DE Gas Filing

Requested Revenue Requirement Increase ^(1,2)	\$11.0M
Requested ROE	10.10%
Requested Common Equity Ratio	50.52%
Order Expected	Q4 2018

Pepco DC Electric Filing

Requested Revenue Requirement Increase ⁽¹⁾	\$66.2M
Requested ROE	10.10%
Requested Common Equity Ratio	50.28%
Order Expected	12/2018

Pepco MD Electric Filing

Requested Revenue Requirement Increase ^(1,4)	\$10.7M
Requested ROE	10.10%
Requested Common Equity Ratio	50.28%
Order Expected	7/31/18

(1) Revenue requirement includes changes in depreciation and amortization expense where applicable, which have no impact on pre-tax earnings

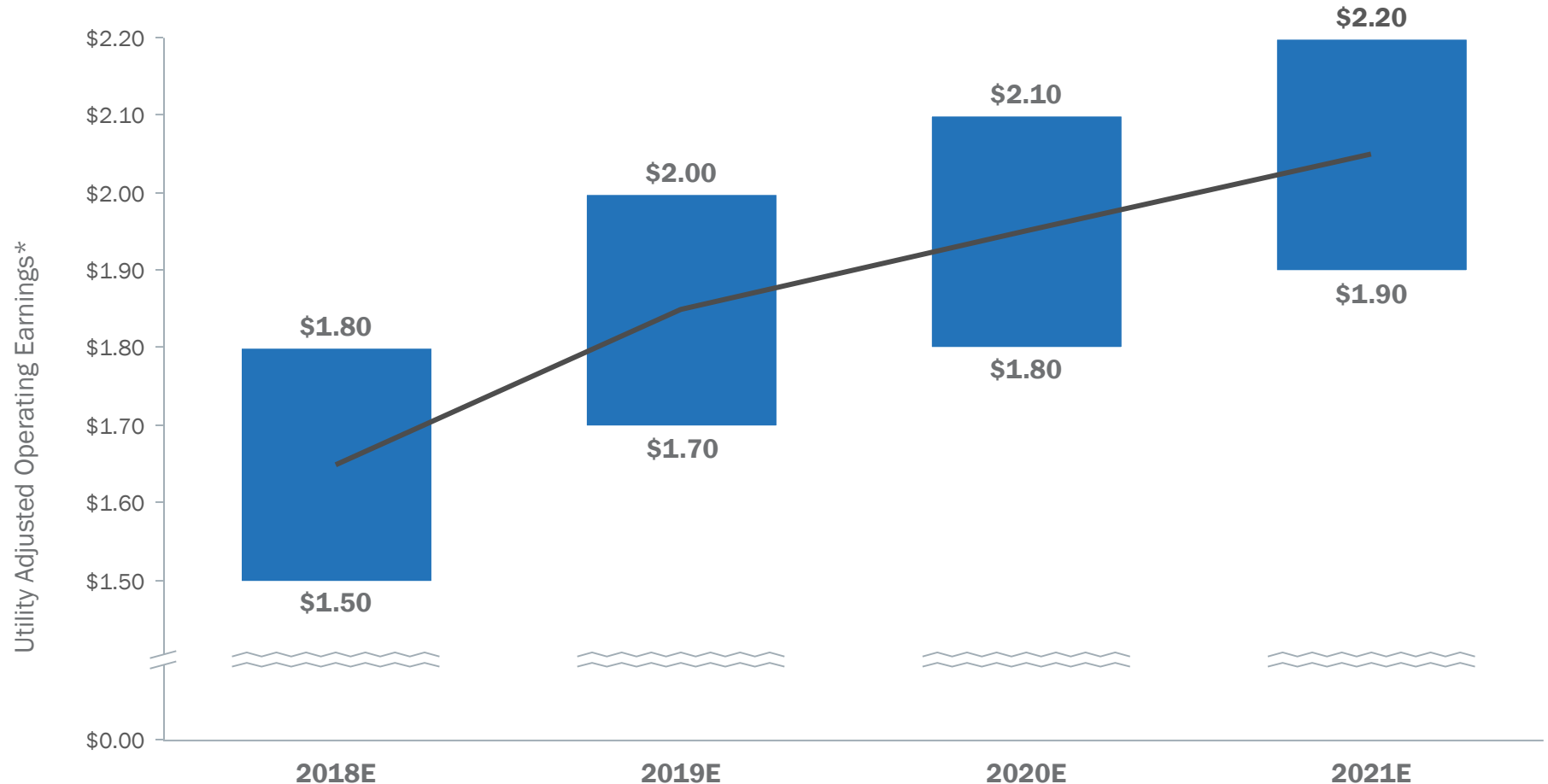
(2) As permitted by Delaware law, Delmarva Power implemented interim rate increases of \$2.5M in Q3 2017 and will implement full allowable rates on March 17, 2018, subject to refund

(3) Solely for purposes of calculating the Allowance for Funds Used During Construction and regulatory asset carrying costs

(4) On February 5, 2018, Pepco filed with the MDPSC an update to its current distribution rate case to reflect approximately \$30.7 million in annual tax savings resulting from the enactment of the TCJA

Exelon Utilities EPS* Growth of 6-8% to 2021

Exelon Utilities Operating Earnings* 2018-2021



Rate base growth combined with PHI ROE improvement drives EPS growth

Note: Includes after-tax interest expense held at Corporate for debt associated with existing utility investment

Exelon Generation: Gross Margin Update

	December 31, 2017			Change from September 30, 2017	
Gross Margin Category (\$M) ⁽¹⁾	2018	2019	2020	2018	2019
Open Gross Margin ^(2,5) (including South, West, Canada hedged gross margin)	\$4,350	\$3,900	\$3,750	\$450	\$200
Capacity and ZEC Revenues ^(2,5,6)	\$2,300	\$2,000	\$1,850	-	-
Mark-to-Market of Hedges ^(2,3)	\$350	\$400	\$250	\$(300)	\$(50)
Power New Business / To Go	\$550	\$750	\$900	\$(150)	\$(100)
Non-Power Margins Executed	\$200	\$100	\$100	-	-
Non-Power New Business / To Go	\$300	\$400	\$400	-	-
Total Gross Margin*^(4,5)	\$8,050	\$7,550	\$7,250	-	\$50

Recent Developments

- In 2018, Total Gross Margin is flat compared to September 30, 2017, with the retention of Handley Generating Station adding \$50M, offset by the early retirement of Oyster Creek which lowers Gross Margin by \$50M
- In 2019, Total Gross Margin is up \$150M on a combination of higher power prices, strengthening ERCOT spark spreads, and additional generation from Handley, partly offset by early retirement of Oyster Creek which lowers Gross Margin by \$100M
- Relative to 2019, 2020 Total Gross Margin is lower by \$300M:
 - \$150M lower driven by reduction in Open Gross Margin primarily related to TMI retirement
 - \$150M lower Capacity revenues from lower PJM and NE capacity prices
- Behind ratable hedging position reflects the upside we see in power prices
 - ~13-16% behind ratable in 2018 when considering cross commodity hedges

(1) Gross margin categories rounded to nearest \$50M

(2) Excludes EDF's equity ownership share of the CENG Joint Venture

(3) Mark-to-Market of Hedges assumes mid-point of hedge percentages

(4) Based on December 31, 2017, market conditions

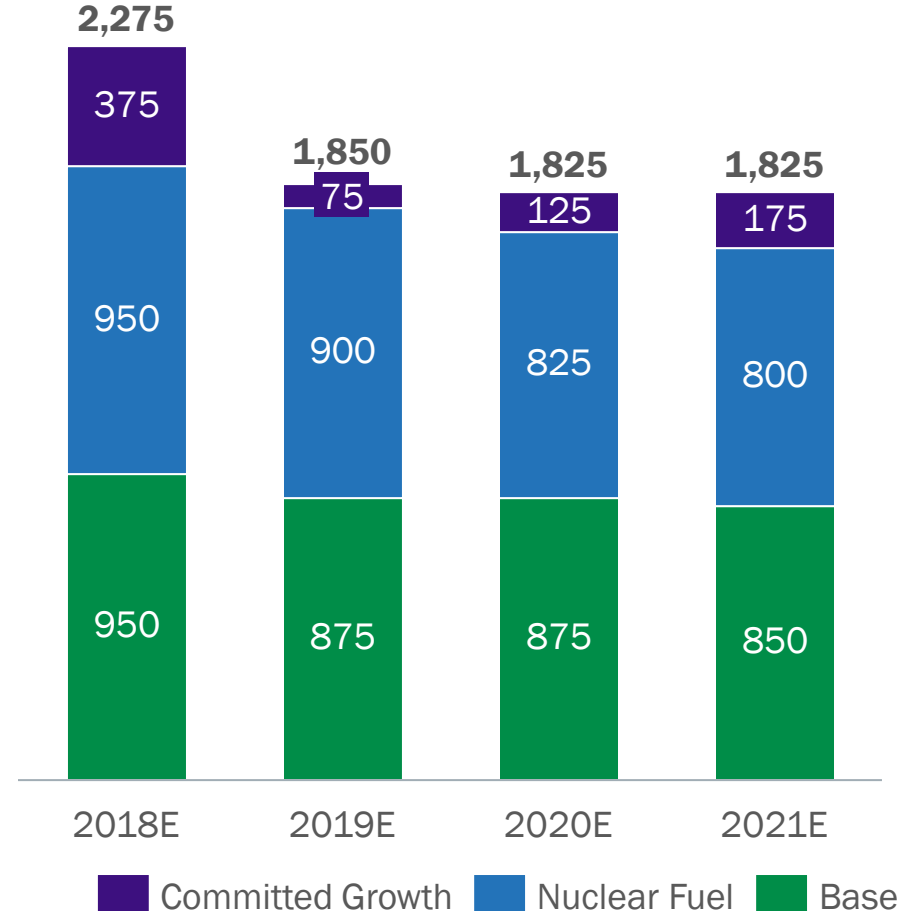
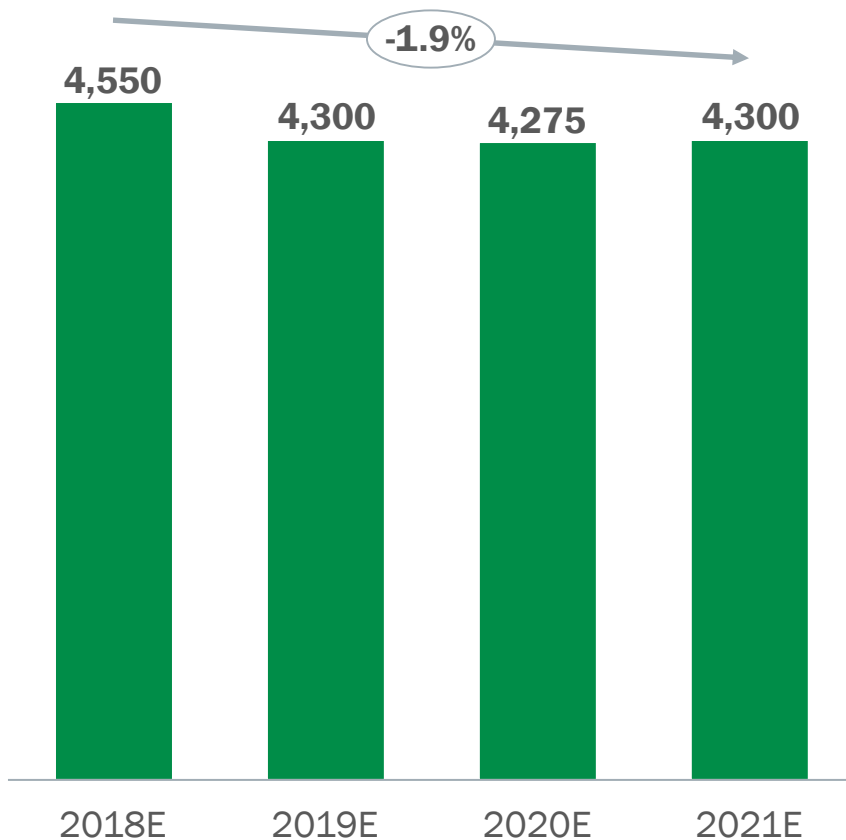
(5) Reflects Oyster Creek and TMI retirements in October 2018 and September 2019, respectively. EGTP removal impacts full year 2018, 2019, and 2020 and is adjusted for retaining Handley Generating Station.

(6) 2018 includes \$150M of IL ZEC revenues associated with 2017 production

Driving Costs and Capital Out of the Generation Business

Adjusted O&M* (\$M)^(1,2)

Capital Expenditures (\$M)^(1,3,4)



Cost optimization programs and planned nuclear plant closures drive lower total O&M

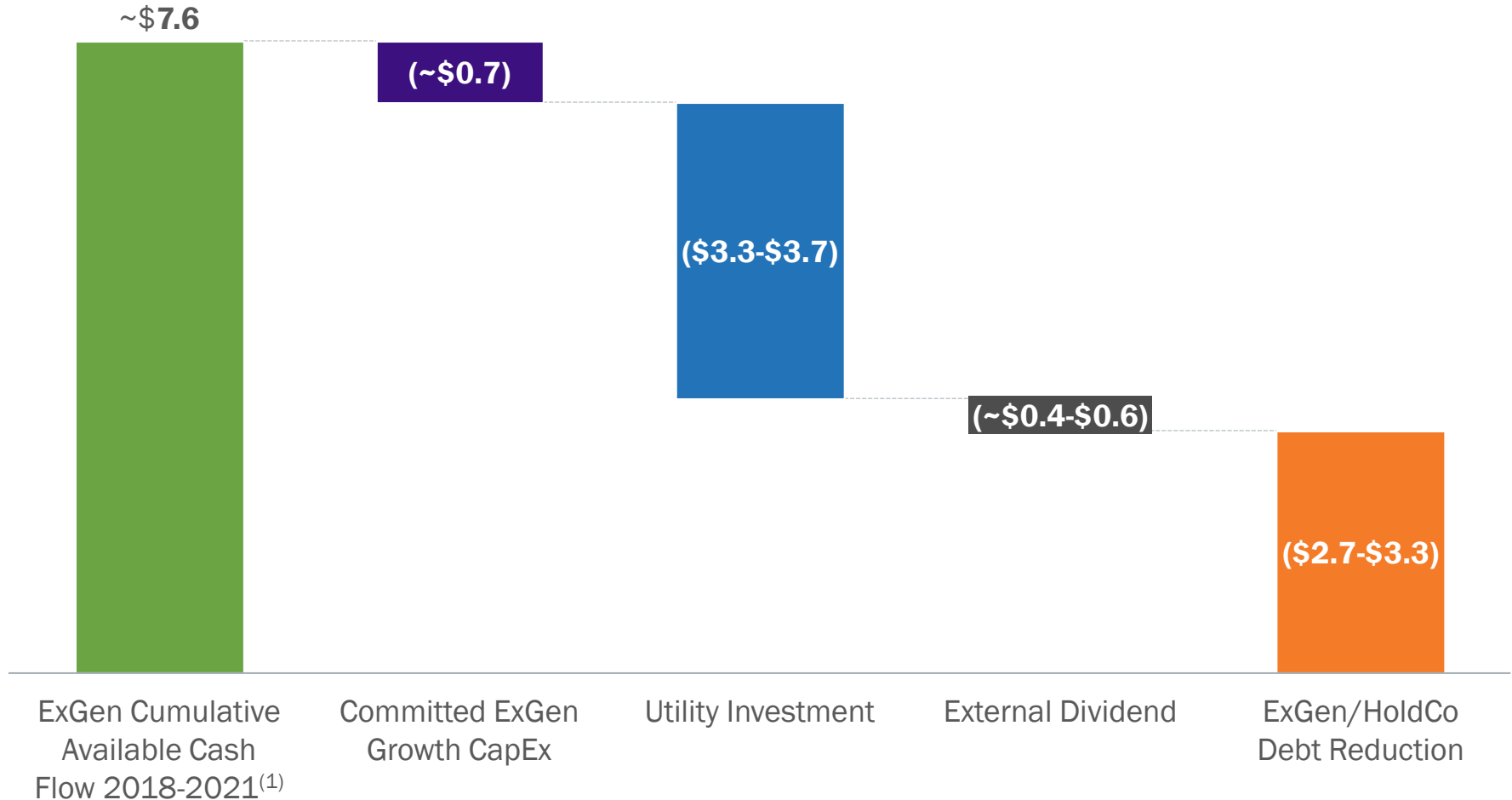
- (1) All amounts rounded to the nearest \$25M
 (2) O&M and Capital Expenditures reflect removal of Oyster Creek and TMI in 2018 and 2019, respectively, and removal of EGTP in 2018 forward, adjusted for retaining Handley Generating Station
 (3) Capital spend represents cash CapEx with CENG at 100% and excludes merger commitments
 (4) 2018E growth capital expenditures reflects a ~\$175M shift of cash outlay from 2017A to 2018E related to timing of payments for the CCGT projects in Texas

ExGen's Strong Available Cash Flow* Supports Utility Growth and Debt Reduction

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2018-2021 Exelon Generation Available Cash Flow and Uses of Cash* (\$B)



Redeploying Exelon Generation's available cash flow* to maximize shareholder value

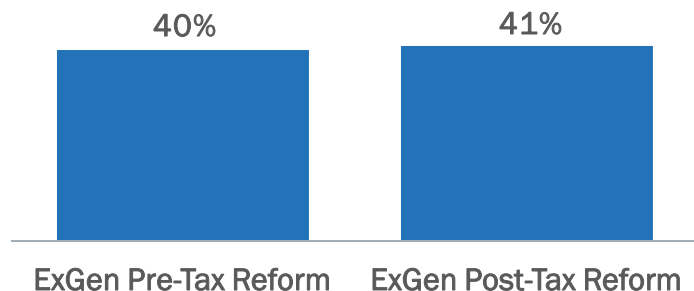
(1) Cumulative Available Cash Flow* is a midpoint of a range based on December 31, 2017, market prices. Sources include change in margin, tax sharing agreement, equity investments, equity distributions for renewables JV and Bluestem tax equity, and acquisitions and divestitures.

Impacts from Tax Reform

Tax Impacts

	2018	2019	2020	2021
Cumulative Incremental Rate Base from Tax Policy Changes	\$0.9	\$1.4	\$1.7	\$2.0
ExGen Effective Tax Rate	22%	22%	22%	21%
Consolidated Effective Tax Rate	18%	19%	20%	20%
Consolidated Cash Tax Rate	1%	4%	3%	3%

2018 ExGen S&P FFO/Debt %*

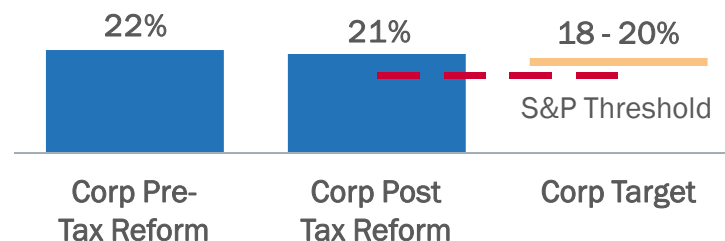


Reflects the increased free cash flow as a result of tax rates decreasing to 22% from an expected 33% in 2018

Key Takeaways

- Changes in federal tax policy are expected to increase run-rate EPS by \$0.10 per share in 2019
- Utility rate base is expected to be \$1.7B higher in 2020 than prior disclosures
- Generation cash flows will benefit from a lower tax rate and full expensing of capital with an effective tax rate of 22% in 2018-2020, and 21% in 2021
- Projected Exelon FFO/Debt is largely unchanged with ExGen metrics stronger and modest deterioration at the six regulated utilities, which remain at or above rating agency thresholds

2018 Exelon S&P FFO/Debt %*(1,2)



Impact of tax reform on Exelon's metrics is largely neutral given offsetting impacts between ExGen and utilities

(1) Due to ring-fencing, S&P deconsolidates BGE from Exelon and analyzes solely as an equity investment

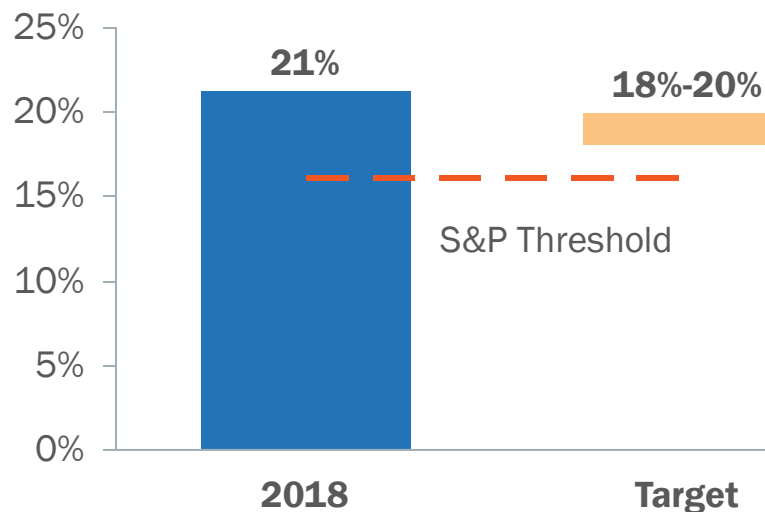
(2) Exelon Corp downgrade threshold (red dotted line) is based on the S&P Exelon Corp Summary Report; represents minimum level to maintain current Issuer Credit Rating of BBB at Exelon Corp

Maintaining Strong Investment Grade Credit Ratings is a Top Financial Priority

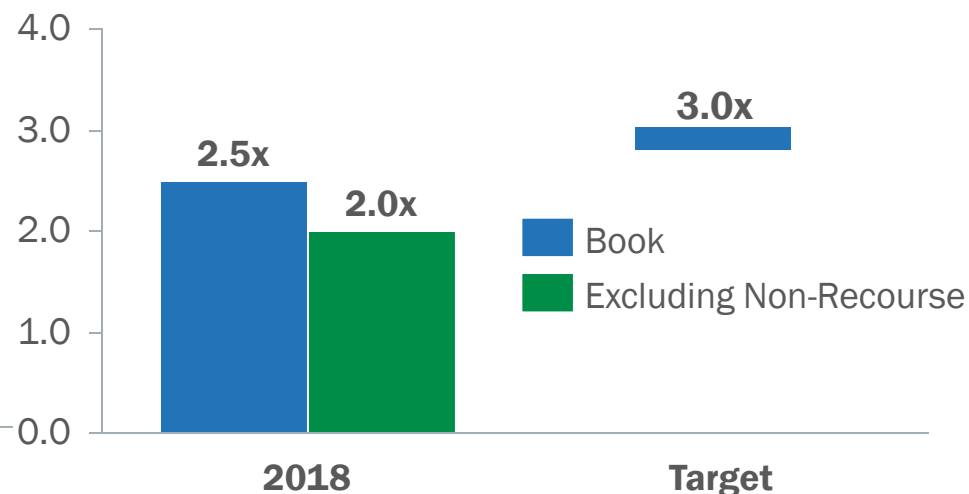
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Exelon S&P FFO/Debt %^{*(1,4)}



ExGen Debt/EBITDA Ratio^{*(5)}



Credit Ratings by Operating Company

Current Ratings ^(2,3)	ExCorp	ExGen	ComEd	PECO	BGE	ACE	DPL	Pepco
Moody's	Baa2	Baa2	A1	Aa3	A3	A3	A2	A2
S&P	BBB-	BBB	A-	A-	A-	A	A	A
Fitch	BBB	BBB	A	A	A-	A-	A	A-

(1) Due to ring-fencing, S&P deconsolidates BGE from Exelon and analyzes solely as an equity investment

(2) Current senior unsecured ratings as of February 7, 2018, for Exelon, Exelon Generation and BGE and senior secured ratings for ComEd, PECO, ACE, DPL, and Pepco

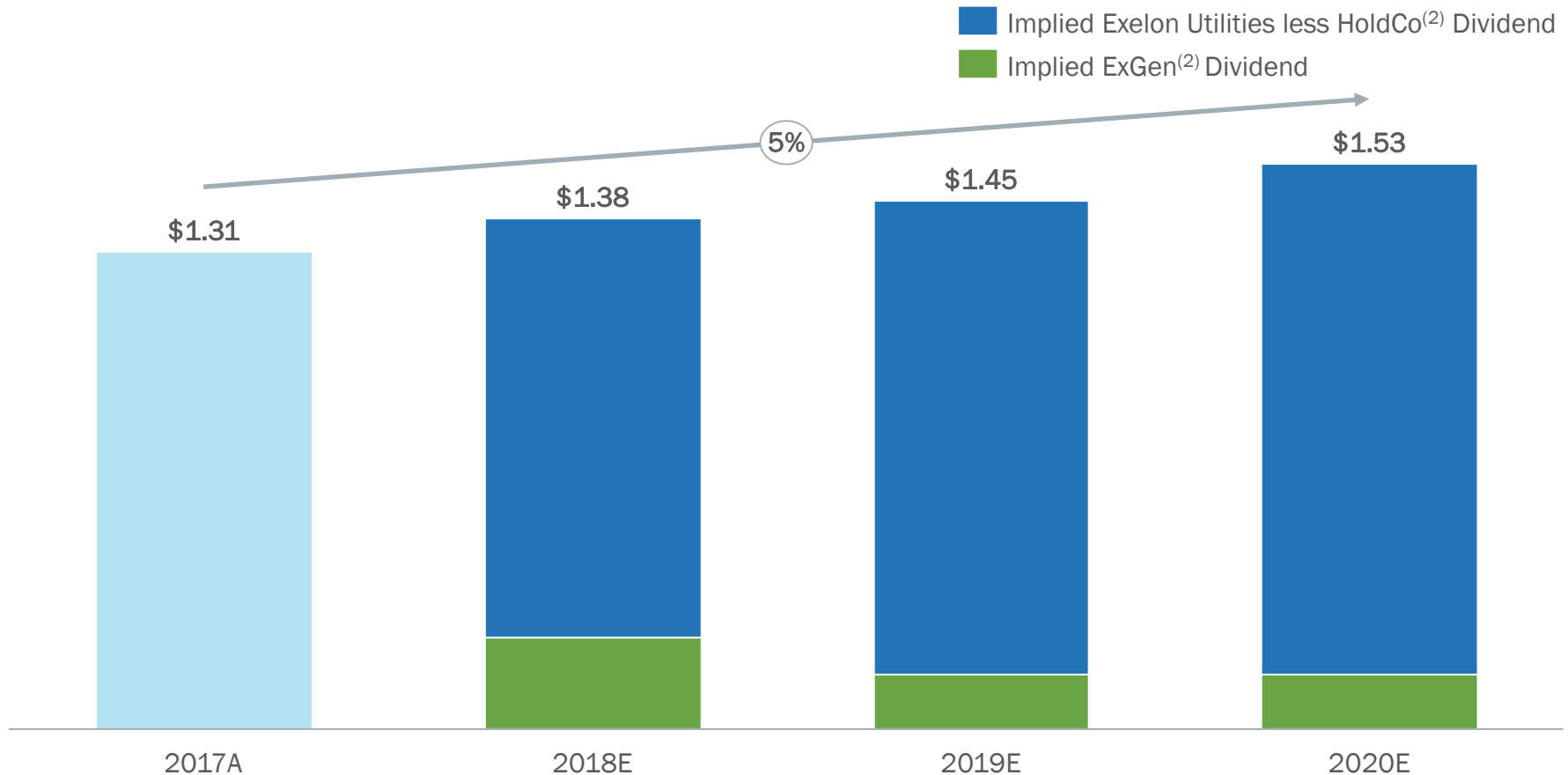
(3) All ratings have a "Stable" outlook

(4) Exelon Corp downgrade threshold (red dotted line) is based on the S&P Exelon Corp Summary Report; represents minimum level to maintain current Issuer Credit Rating of BBB at Exelon Corp

(5) Reflects net book debt (YE debt less cash on hand) / adjusted operating EBITDA*

Raising Dividend Growth Rate to 5% Annually through 2020

Dividends per Share⁽¹⁾



Assuming a steady 70% payout ratio on Utility less HoldCo earnings, ExGen's contribution to the Exelon dividend represents a modest payout on earnings and free cash flow

(1) Quarterly dividends are subject to declaration by the board of directors

(2) Total projected Dividend per Share (DPS) figures are illustrative of a 5% growth annually applied to the 2017 dividend. Implied Exelon Utilities contribution is based on a 70% payout on the midpoint of the EPS guidance band for Exelon Utilities less HoldCo. Implied ExGen contribution is based on the remaining balance between the illustrative total annual DPS and the Implied Exelon Utilities contribution.

Resiliency and Energy Market Reform

Price Formation

- PJM has stated that it is committed to advancing its proposal to allow all resources to set LMP and to improving scarcity pricing
- PJM issued “Proposed Enhancements to Energy Price Formation” whitepaper in November 2017
- January 8, 2018, FERC order on resilience invited RTOs to submit filings discussing potential paths forward for addressing any identified gaps or exposure on the resilience of the bulk power system
- “One of the most important things that we have been focused on is how does our market . . . actually compensate for resources that are providing reliability services? We've proposed key reforms and have engaged in discussion about key reforms on what we call price formation...we're looking for FERC and certainly we'll work with FERC to put time discipline on these discussions to address these in a timely manner.” - PJM CEO and President Andrew Ott at Senate ENR Committee hearing on January 23, 2018

Resiliency

- FERC issued “Grid Reliability and Resilience Pricing” order on January 8, 2018, to open new docket on resilience
- “The Commission recognizes that we must remain vigilant with respect to resilience challenges, because affordable and reliable electricity is vital to the country’s economic and national security.” – January 8 order at 1
- “[W]e are not ending our work on the issue of resilience. To the contrary, we are initiating a new proceeding to address resilience in a broader context” - January 8 order at 7
- “As we stated in our order, we appreciate the secretary reinforcing the importance of the resilience of our bulk power system as an issue that warrants further attention and, as we said in our order, prompt attention.... it's something where I have declared it, and our order declares it to be a matter of priority for this commission...Those are not words we utter very often – it is a declared priority of the Commission ” - FERC Chairman Kevin McIntyre at Senate ENR Committee hearing on January 23, 2018

In 2018, FERC and PJM are considering action on price formation and valuing the attribute of resilience, both of which should directly benefit our 24x7 nuclear fleet

New York ZEC Legal Challenges

Federal Case:

- Case dismissed on July 25 and judgment entered on July 27
- “The ZEC program does not thwart the goal of an efficient energy market; rather, it encourages through financial incentives the production of clean energy”
- On August 24, the plaintiffs appealed to the US Court of Appeals for the 2nd Circuit
- Briefing schedule:
 - Plaintiff-Appellant Opening Brief filed October 13
 - Reply Briefs filed on December 1
 - Oral arguments scheduled for March 12

State case:

- On January 22, the court partially affirmed and partially denied motion to dismiss
- The case will proceed in the trial court and will likely be decided on motions for summary judgment, which could take up to a year

Illinois ZEC Legal Challenges

- Both cases dismissed and judgment entered July 14
- “The ZEC program does not conflict with the Federal Power Act”
- On July 17, both sets of plaintiffs appealed to the US Court of Appeals for the 7th Circuit
- On July 18, the 7th Circuit consolidated the appeals and set a briefing schedule:
 - Plaintiff-Appellant Opening Brief filed August 28
 - Reply Briefs filed on December 12
 - Oral arguments occurred on January 3, 2018 – Judge requested supplemental briefings within 14 days
- Supplemental briefs were filed on January 26
- Parties are awaiting further action by the court

New Jersey ZEC

- In December, two legislative committees in the New Jersey senate and assembly unanimously passed the nuclear diversity credit bill
- On January 8th, the lame duck session of the NJ Legislature came to a close without a vote on the floor
- At the time, Governor-elect Murphy expressed a preference to include support for nuclear in a broader clean energy legislative package that will provide a number of benefits for customers in NJ
- On January 25, an expanded clean energy bill was introduced in the Senate, incorporating the same nuclear support provisions but recharacterizing them as ZECs to reflect new priorities
- Exelon looks forward to continuing to work with Governor Murphy and the legislature in the upcoming session

The Exelon Value Proposition

- **Regulated Utility Growth** with utility EPS rising 6-8% annually from 2017-2021 and rate base growth of 7.4%, representing an expanding majority of earnings
- **ExGen's strong free cash generation** will support utility growth while also reducing debt by ~\$3B over the next 4 years
- **Optimizing ExGen value by:**
 - Seeking fair compensation for the zero-carbon attributes of our fleet;
 - Closing uneconomic plants;
 - Monetizing assets; and,
 - Maximizing the value of the fleet through our generation to load matching strategy
- **Strong balance sheet is a priority** with all businesses comfortably meeting investment grade credit metrics through the 2021 planning horizon
- **Capital allocation priorities targeting:**
 - Organic utility growth;
 - Return of capital to shareholders with 5% annual dividend growth through 2020⁽¹⁾,
 - Debt reduction; and,
 - Modest contracted generation investments

(1) Quarterly dividends are subject to declaration by the board of directors

2018 Business Priorities and Commitments

Maintain industry leading operational excellence

Effectively deploy \$5.4B of 2018 utility capex

Advance PJM power price formation changes in 2018

Prevail on legal challenges to the NY and IL ZEC programs

Seek fair compensation for at-risk plants in NJ and PA

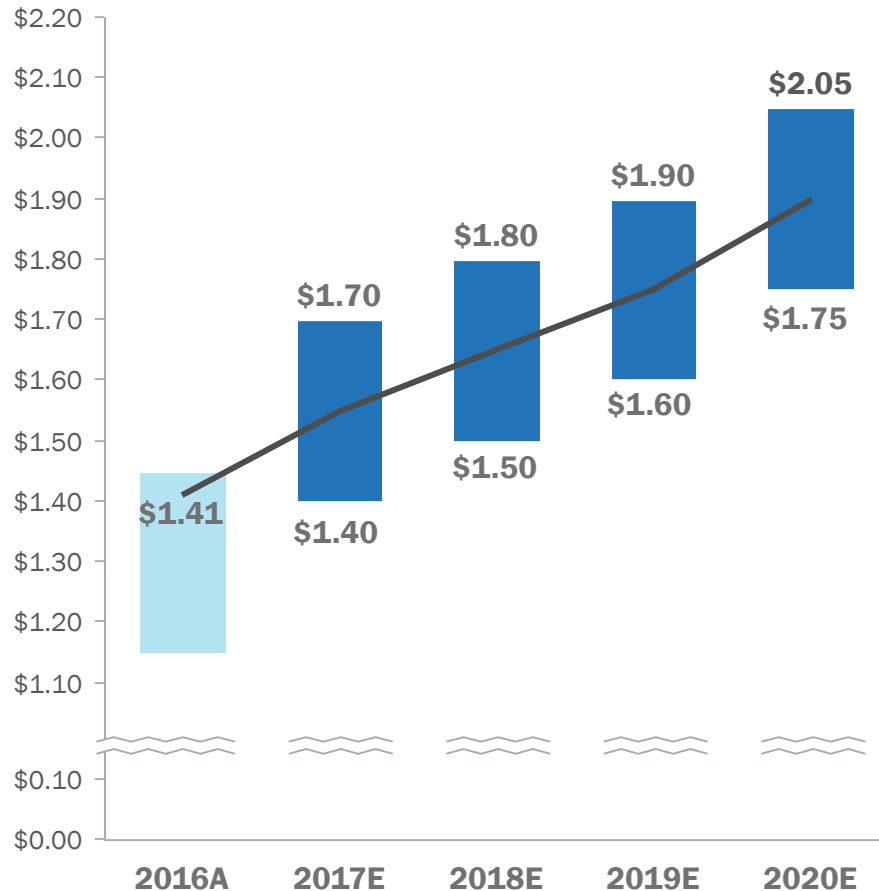
Grow dividend at 5% rate

Continued commitment to corporate responsibility

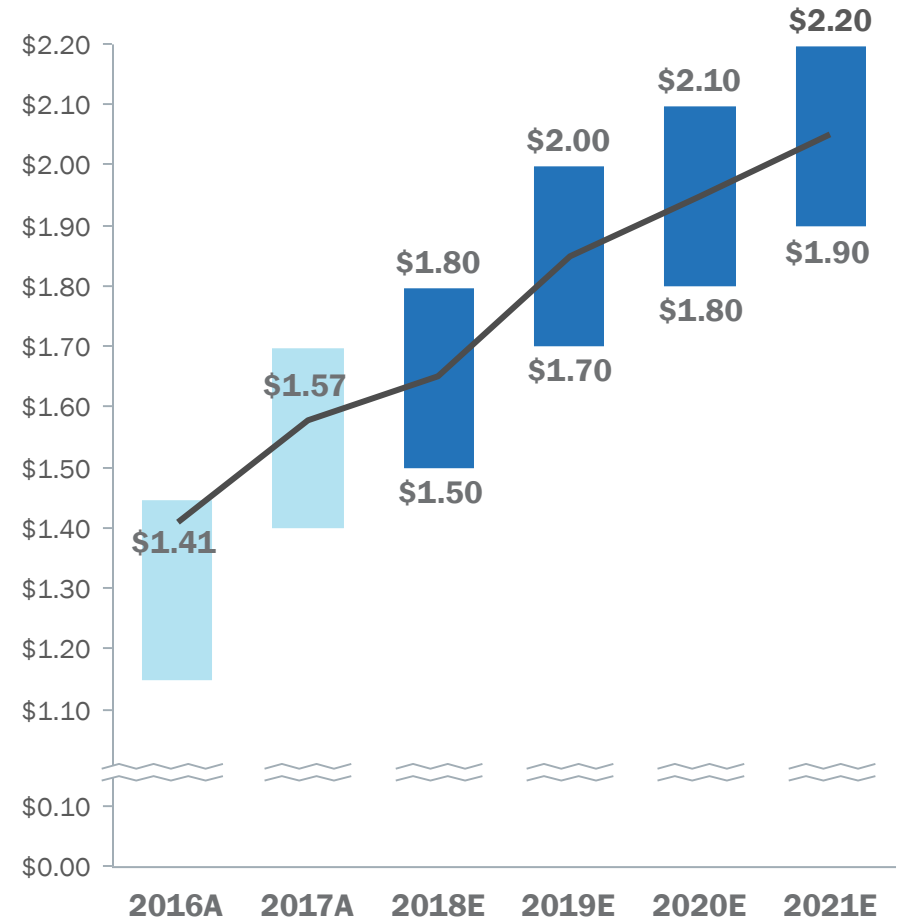
Additional Disclosures

Exelon Utilities EPS Growth of 6-8% from 2018-2021

Q4 2016 Operating Earnings*



Q4 2017 Operating Earnings*

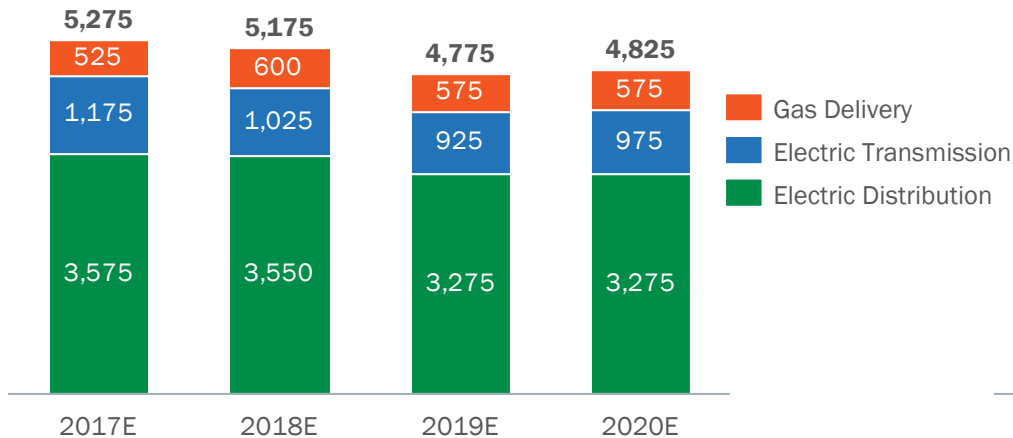


Utility growth rate remains 6-8%, driven by rate base growth and improving PHI ROEs

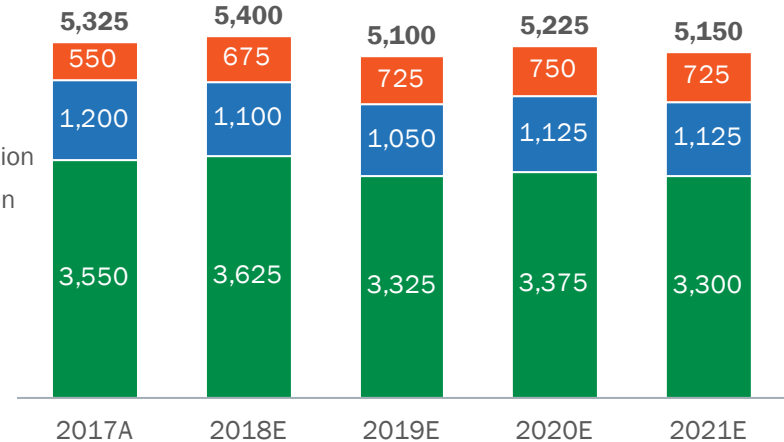
Note: Includes after-tax interest expense held at Corporate for debt costs associated with utility investment.

Utility Capex and Rate Base vs. Previous Disclosure

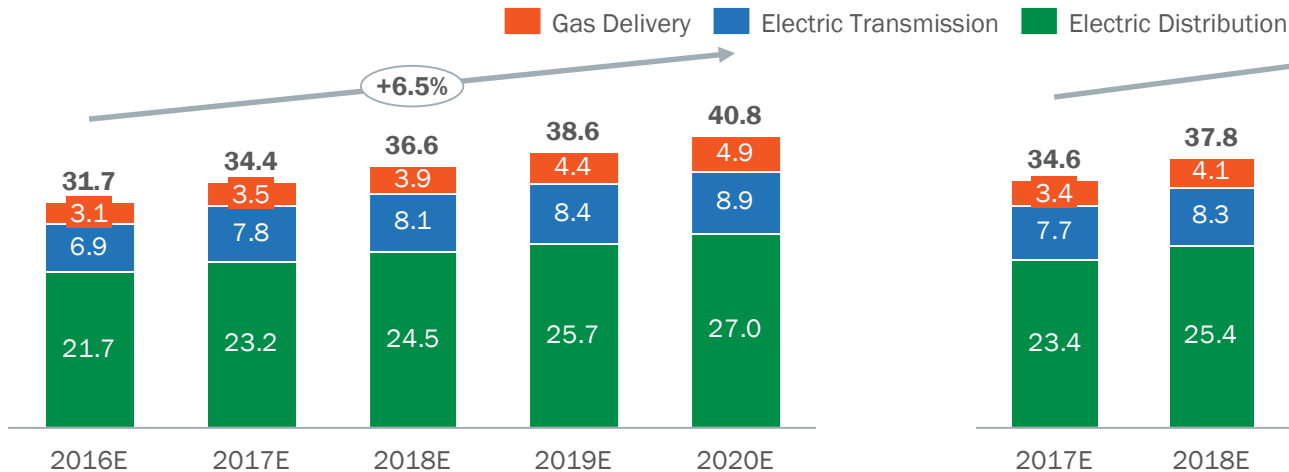
Q4 2016 Capital Expenditures (\$M)



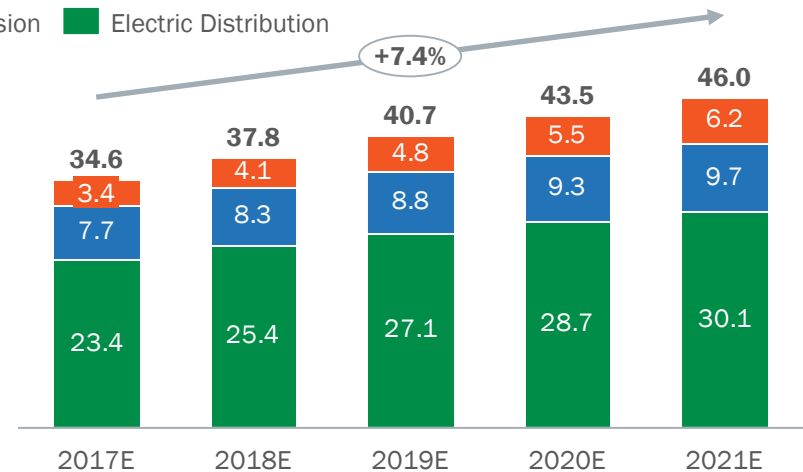
Q4 2017 Capital Expenditures (\$M)



Q4 2016 Rate Base (\$B)



Q4 2017 Rate Base (\$B)

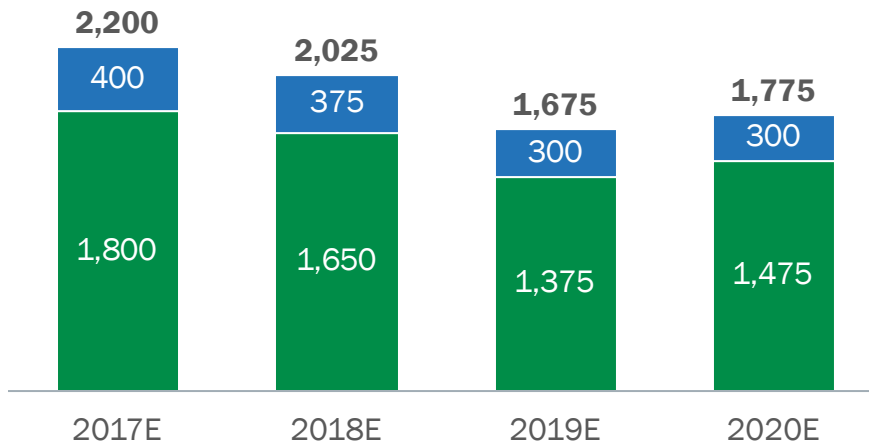


We will invest \$21B of capital in utilities from 2018-2021, supporting rate base growth of 7.4% from 2017-2021

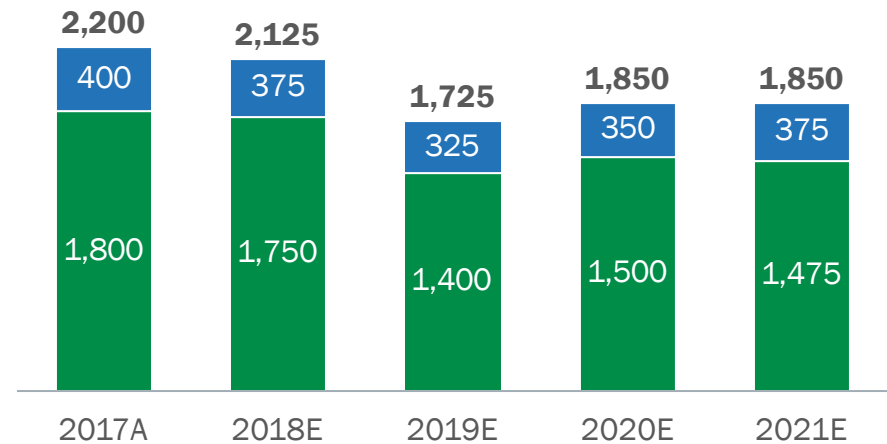
Note: Numbers rounded to nearest \$25M and may not add due to rounding. Rate base reflects year-end estimates.

ComEd Capital Expenditure and Rate Base Forecast

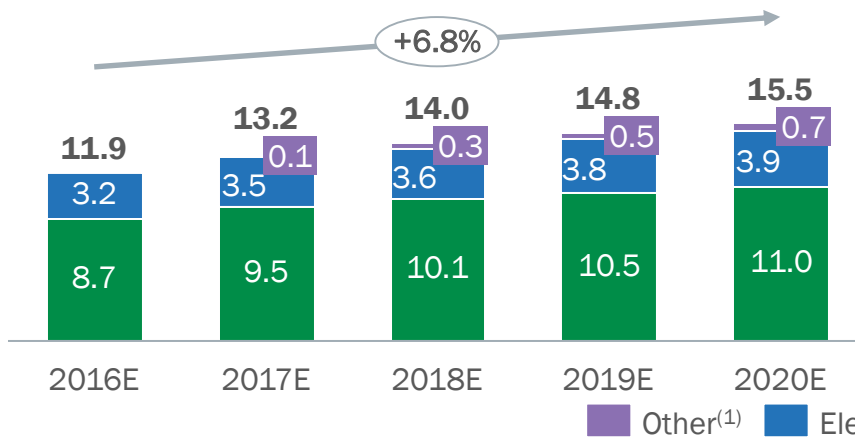
Q4 2016 Capital Expenditures (\$M)



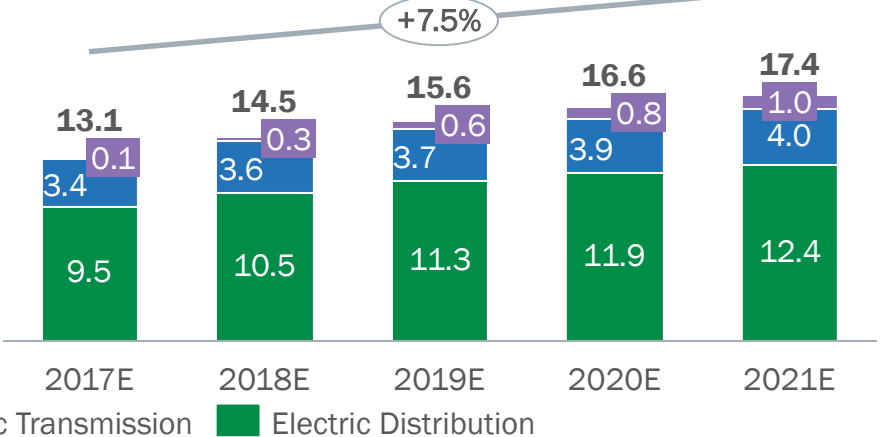
Q4 2017 Capital Expenditures (\$M)



Q4 2016 Rate Base (\$B)



Q4 2017 Rate Base (\$B)



Other⁽¹⁾ Electric Transmission Electric Distribution

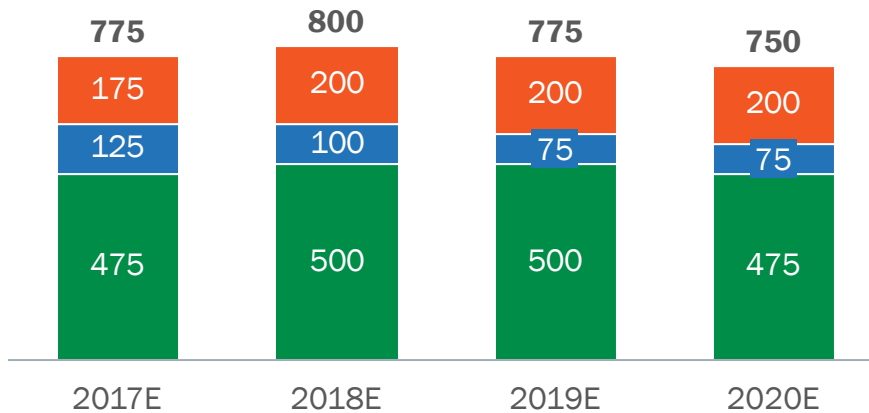
~\$7.6B of Capital being invested from 2018-2021

Note: Numbers rounded to nearest \$25M and may not add due to rounding. Rate base reflects year-end estimates.

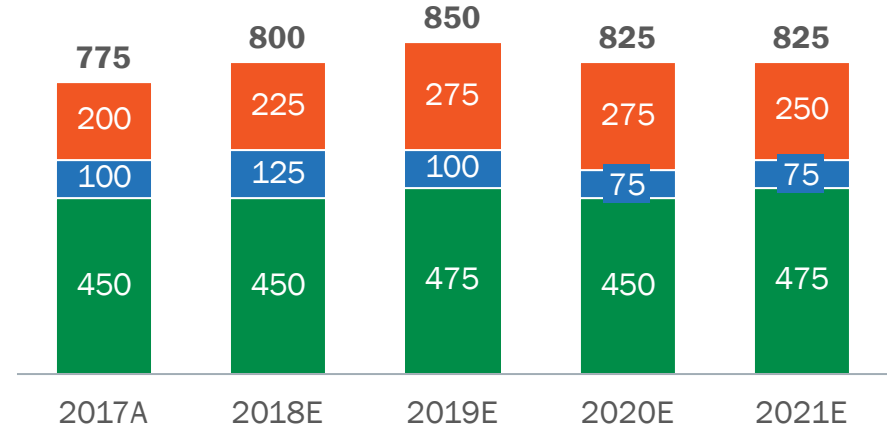
(1) Other includes long-term regulatory assets, which earn a return consistent with rate base, including Energy Efficiency and the Solar Rebate Program

PECO Capital Expenditure and Rate Base Forecast

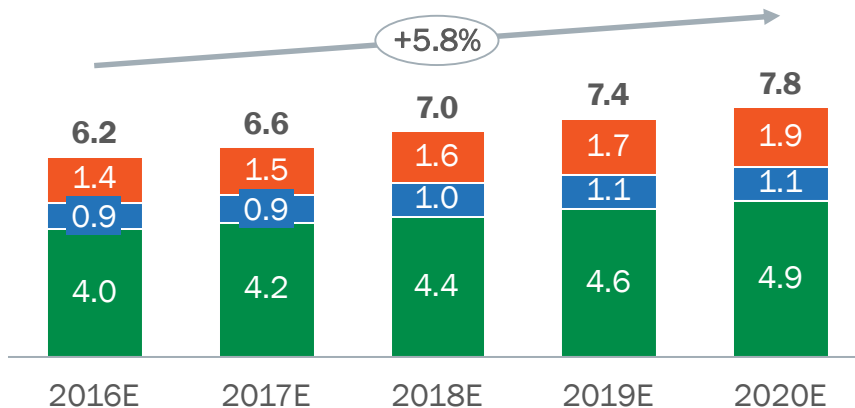
Q4 2016 Capital Expenditures (\$M)



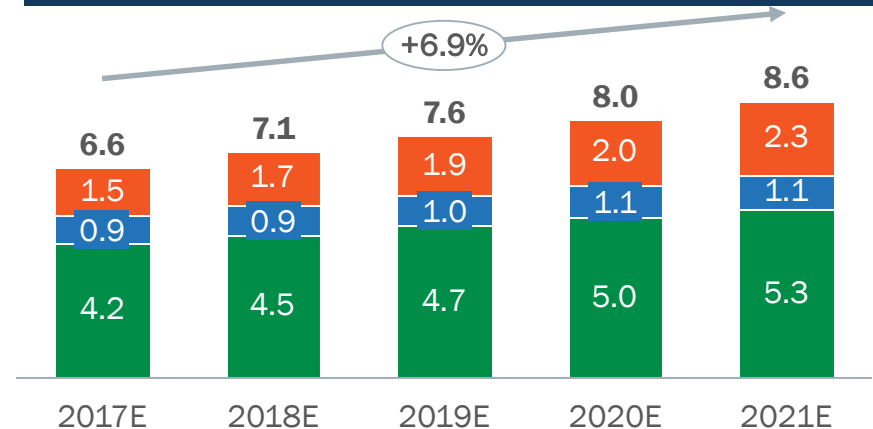
Q4 2017 Capital Expenditures (\$M)



Q4 2016 Rate Base (\$B)



Q4 2017 Rate Base (\$B)



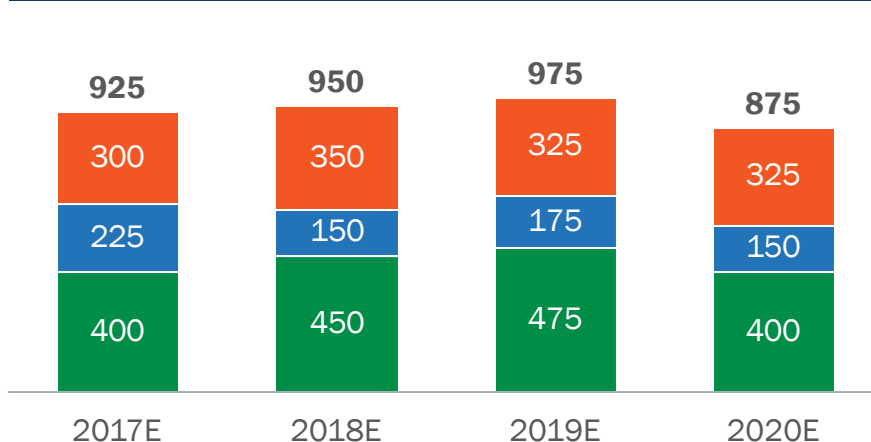
Gas Delivery Electric Transmission Electric Distribution

~\$3.3B of Capital being invested from 2018-2021

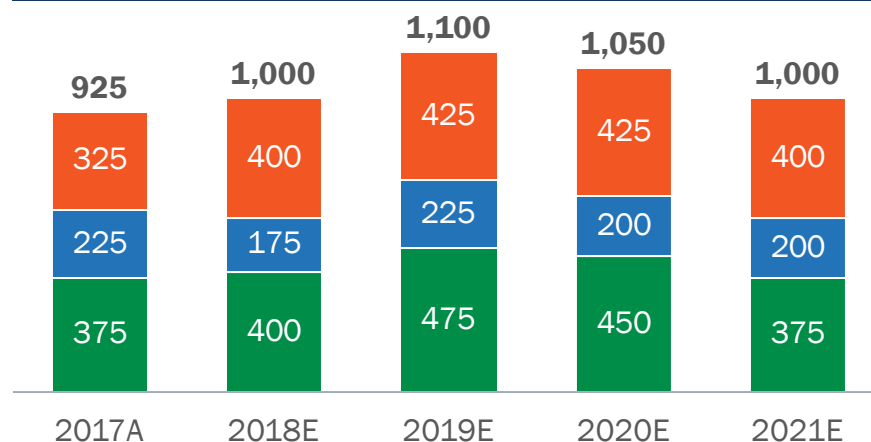
Note: Numbers rounded to nearest \$25M and may not add due to rounding. Rate base reflects year-end estimates.

BGE Capital Expenditure and Rate Base Forecast

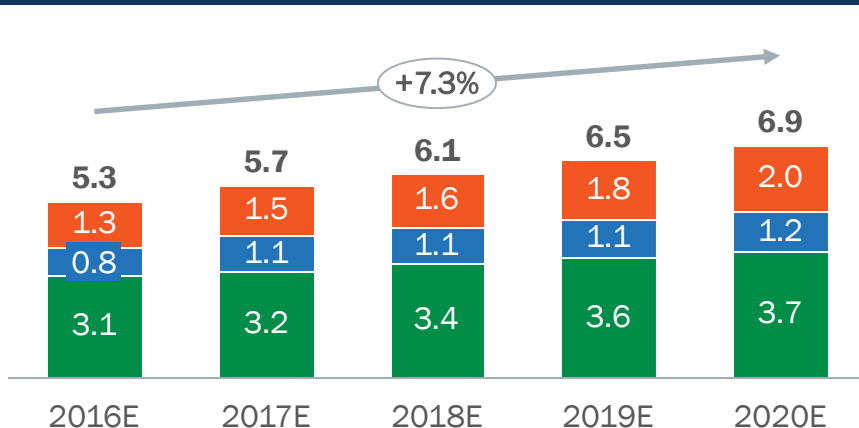
Q4 2016 Capital Expenditures (\$M)



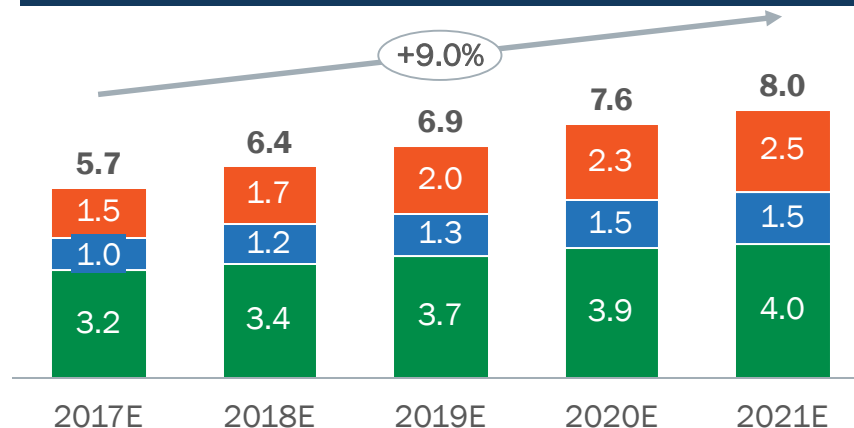
Q4 2017 Capital Expenditures (\$M)



Q4 2016 Rate Base (\$B)



Q4 2017 Rate Base (\$B)



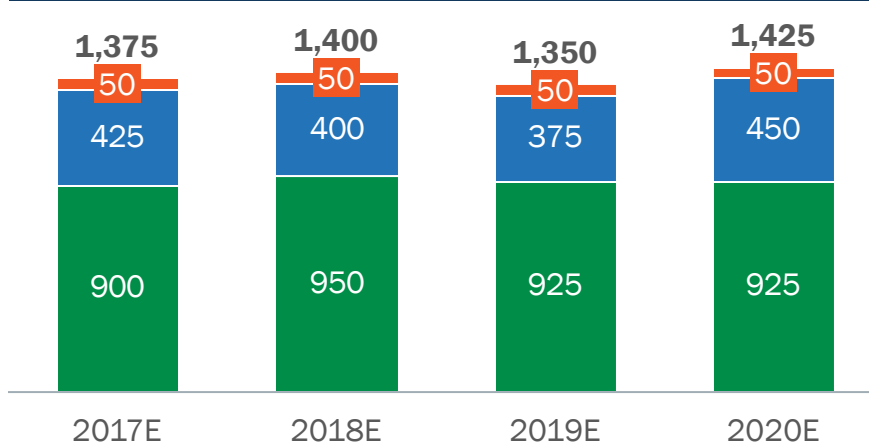
Gas Delivery Electric Transmission Electric Distribution

~\$4.2B of Capital being invested from 2018-2021

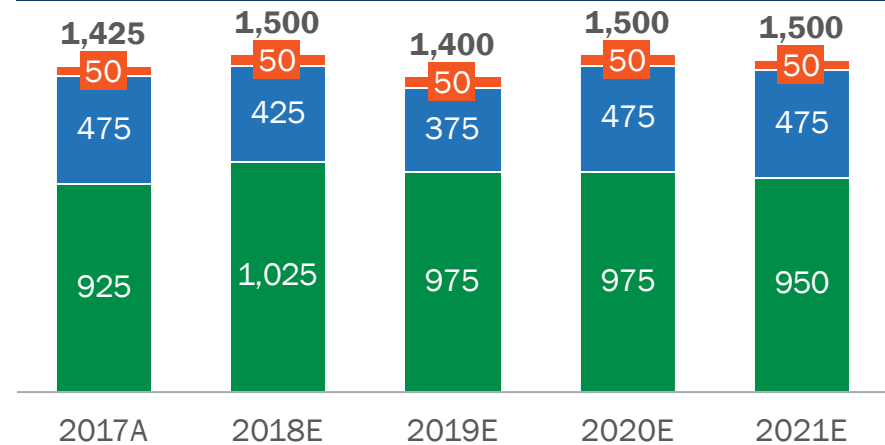
Note: Numbers rounded to nearest \$25M and may not add due to rounding. Rate base reflects year-end estimates.

PHI Consolidated Capital Expenditure and Rate Base Forecast

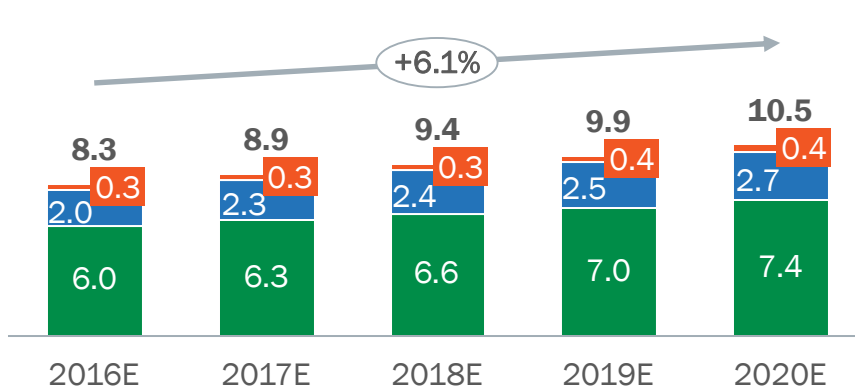
Q4 2016 Capital Expenditures (\$M)



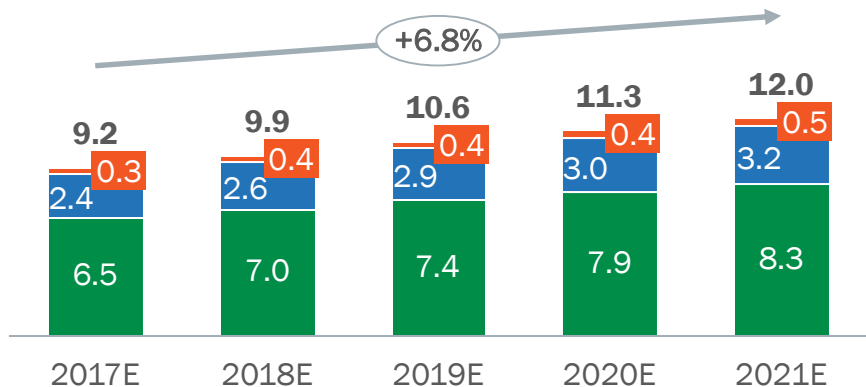
Q4 2017 Capital Expenditures (\$M)



Q4 2016 Rate Base (\$B)



Q4 2017 Rate Base (\$B)



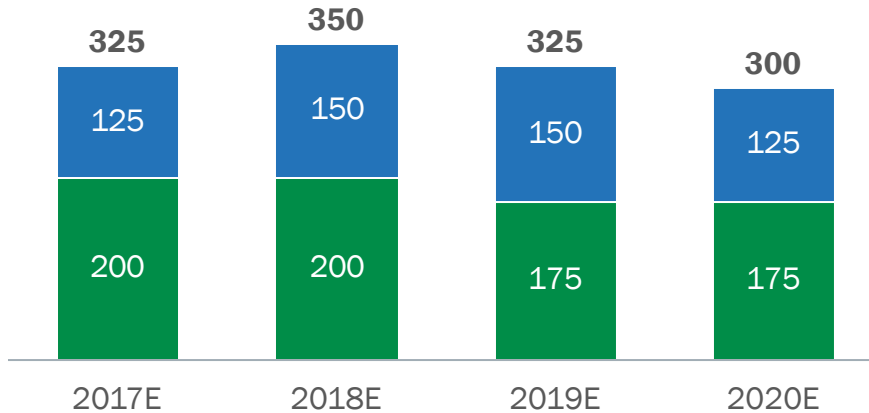
Gas Delivery Electric Transmission Electric Distribution

~\$5.9B of Capital being invested from 2018-2021

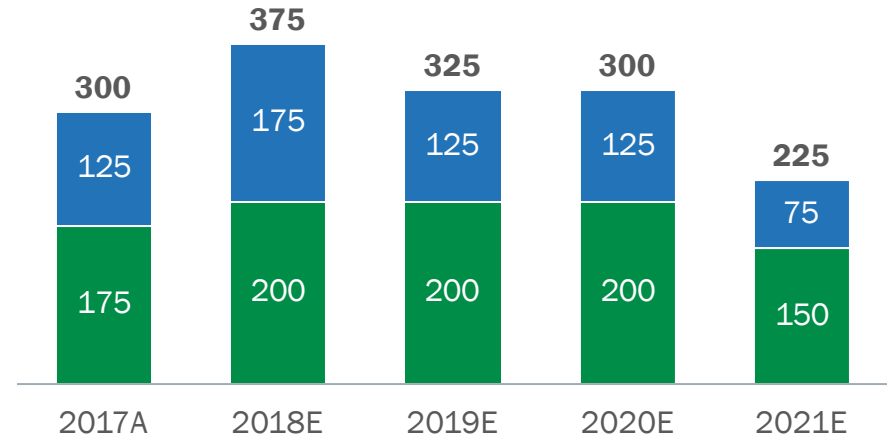
Note: Numbers rounded to nearest \$25M and may not add due to rounding. Rate base reflects year-end estimates.

ACE Capital Expenditure and Rate Base Forecast

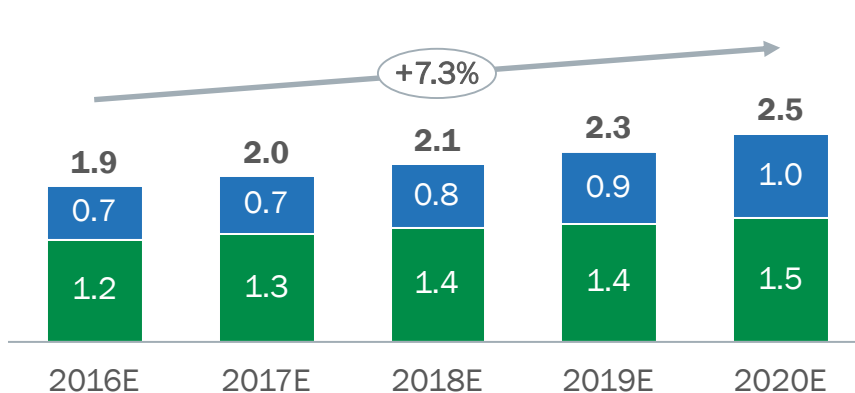
Q4 2016 Capital Expenditures (\$M)



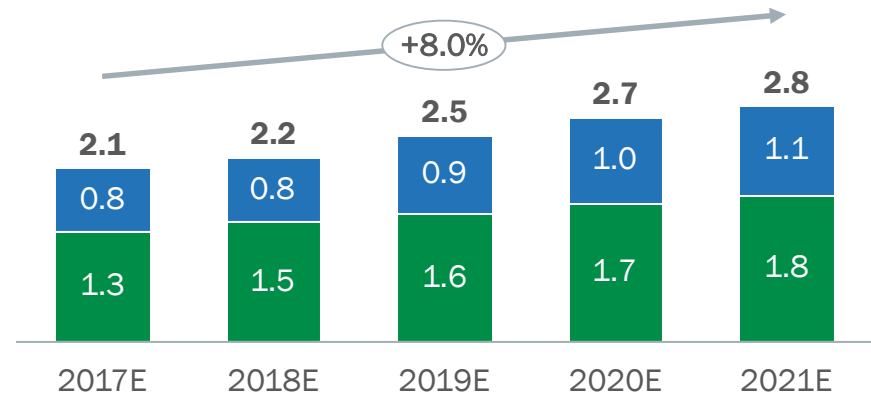
Q4 2017 Capital Expenditures (\$M)



Q4 2016 Rate Base (\$B)



Q4 2017 Rate Base (\$B)



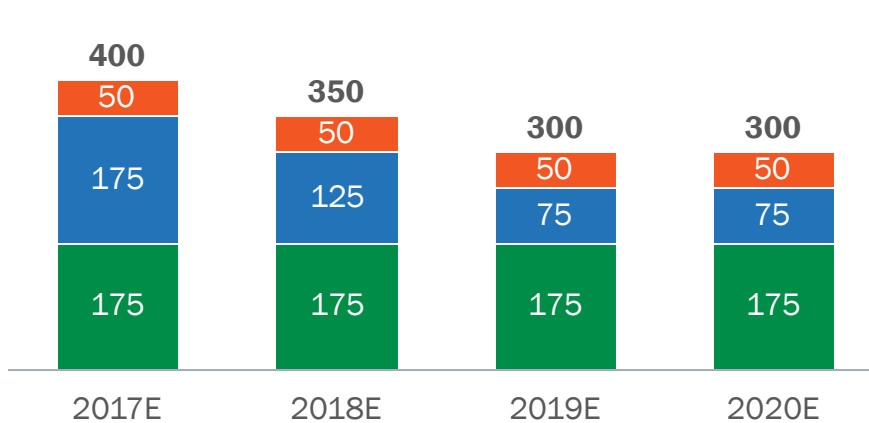
Electric Transmission Electric Distribution

~\$1.2B of Capital being invested from 2018-2021

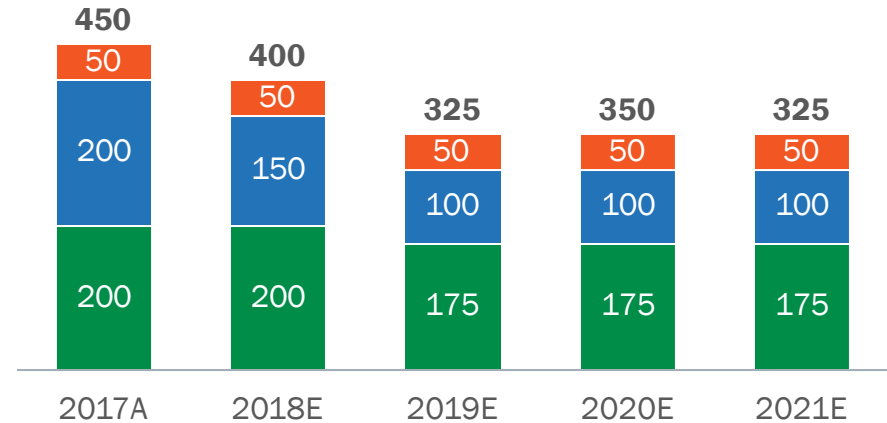
Note: Numbers rounded to nearest \$25M and may not add due to rounding. Rate base reflects year-end estimates.

Delmarva Capital Expenditure and Rate Base Forecast

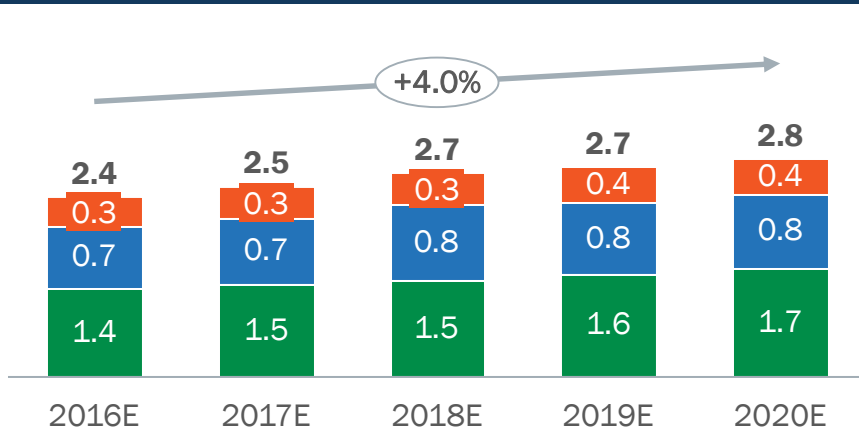
Q4 2016 Capital Expenditures (\$M)



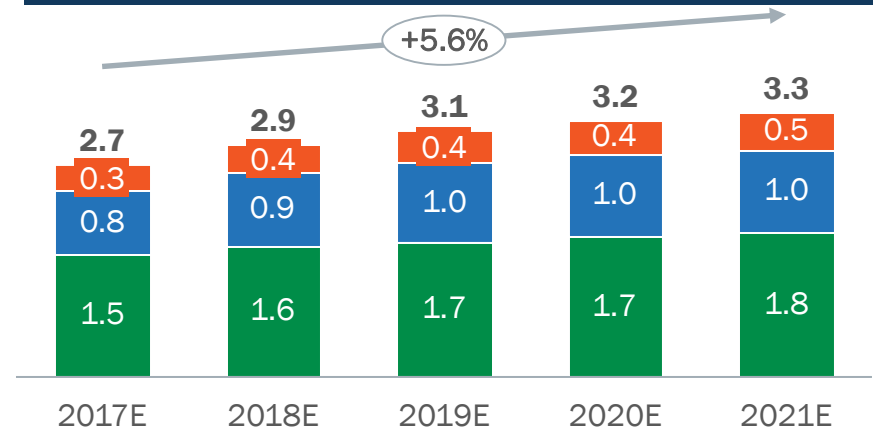
Q4 2017 Capital Expenditures (\$M)



Q4 2016 Rate Base (\$B)



Q4 2017 Rate Base (\$B)



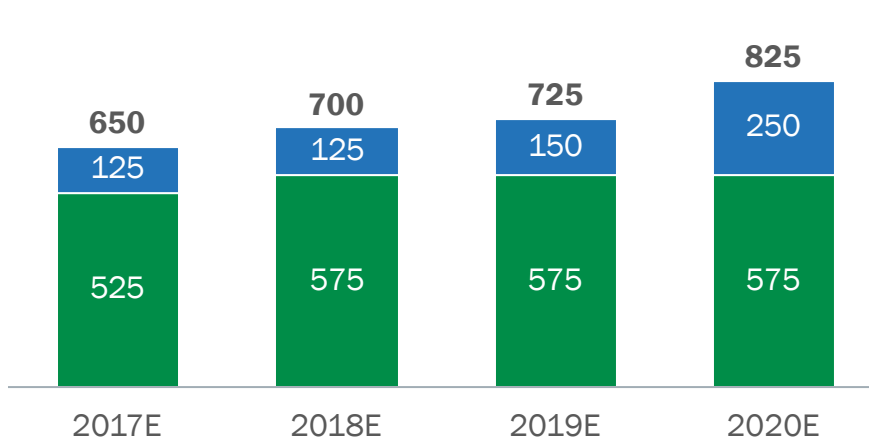
Gas Delivery Electric Transmission Electric Distribution

~\$1.4B of Capital being invested from 2018-2021

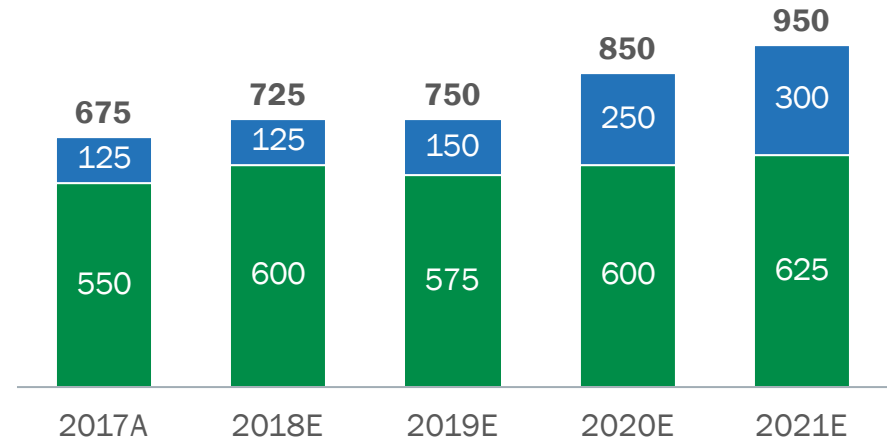
Note: Numbers rounded to nearest \$25M and may not add due to rounding. Rate base reflects year-end estimates.

Pepco Capital Expenditure and Rate Base Forecast

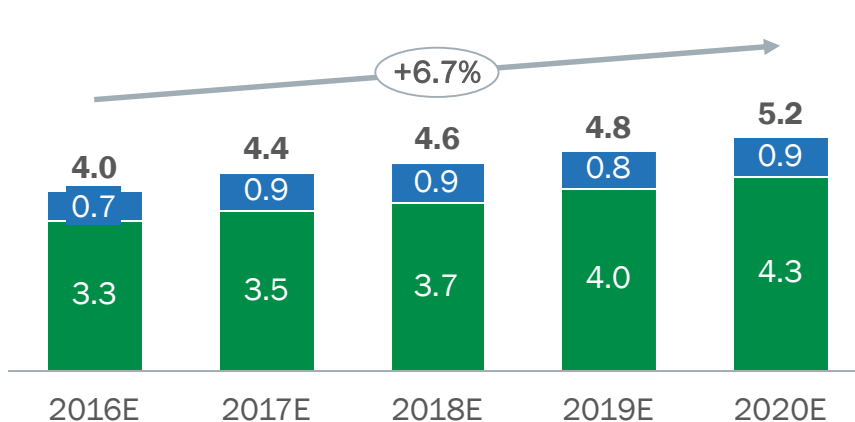
Q4 2016 Capital Expenditures (\$M)



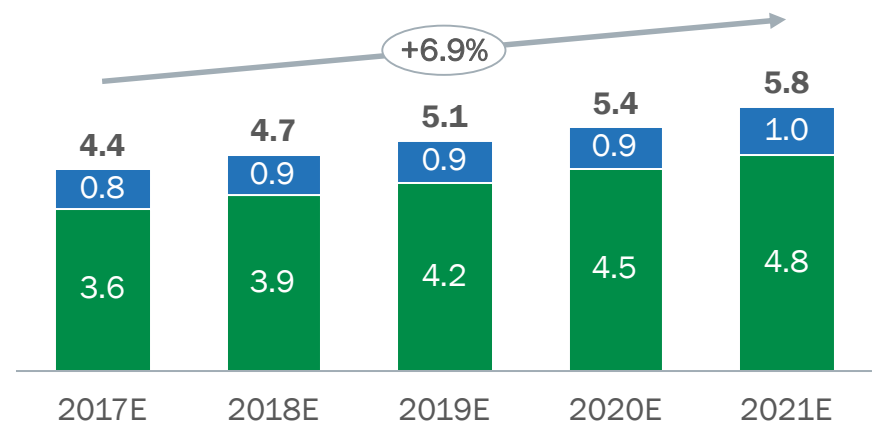
Q4 2017 Capital Expenditures (\$M)



Q4 2016 Rate Base (\$B)



Q4 2017 Rate Base (\$B)



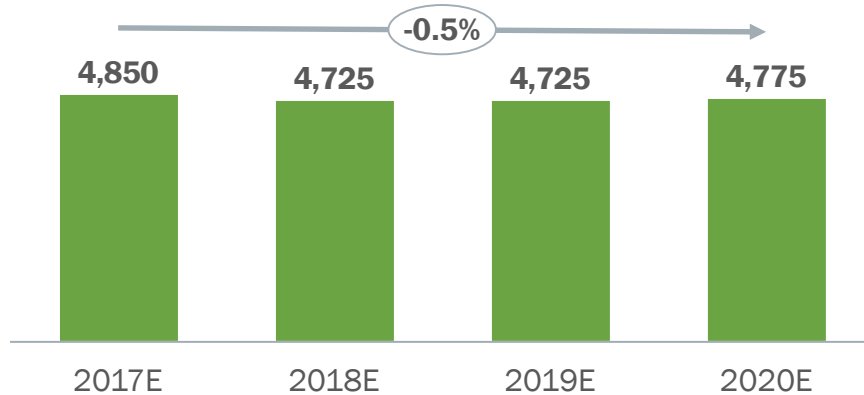
Electric Transmission Electric Distribution

~\$3.3B of Capital being invested from 2018-2021

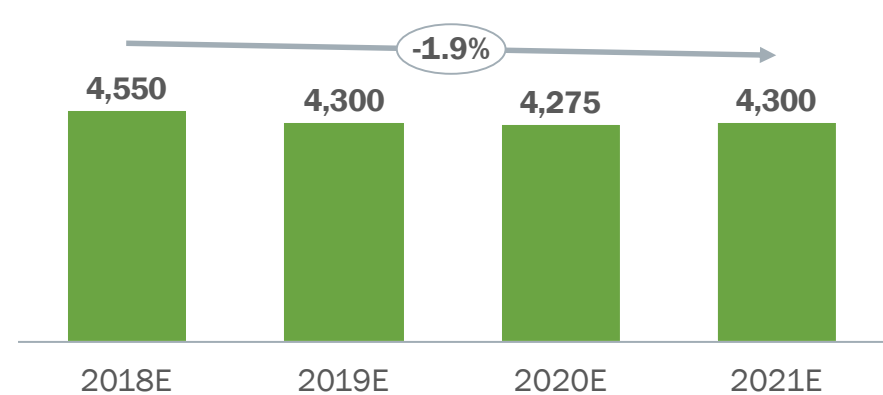
Note: Numbers rounded to nearest \$25M and may not add due to rounding. Rate base reflects year-end estimates.

ExGen O&M and Capex vs. Previous Disclosure

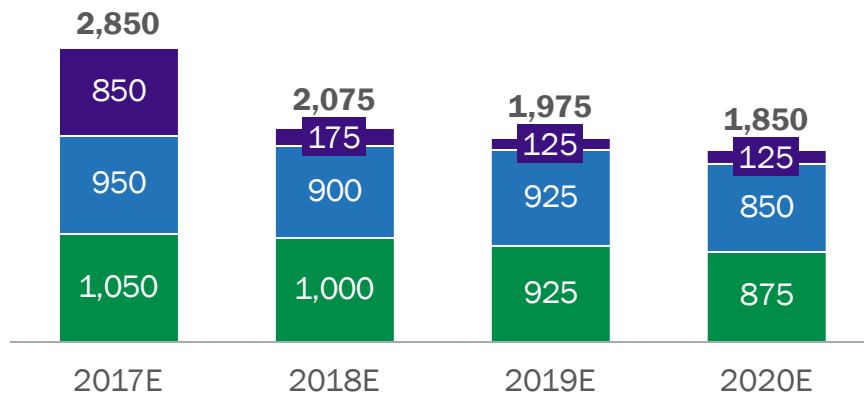
Adjusted O&M* - Q4 2016 (\$M)



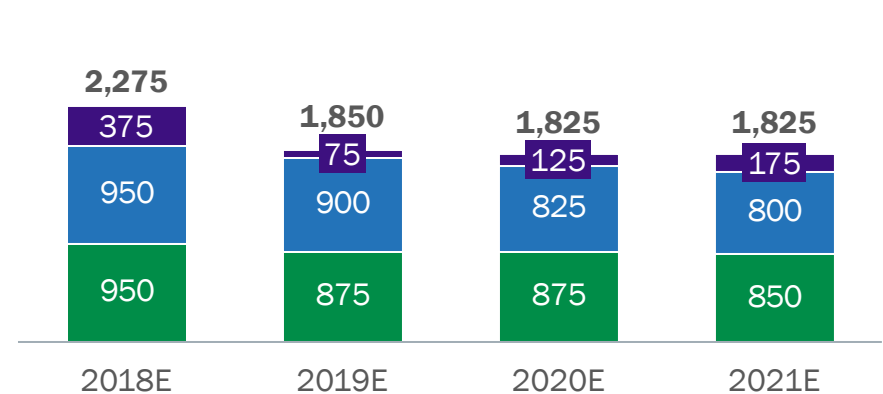
Adjusted O&M* - Q4 2017 (\$M)⁽¹⁾



Capex - Q4 2016 (\$M)⁽²⁾



Capex - Q4 2017 (\$M)^(1,2,3)



Committed Growth Nuclear Fuel Base

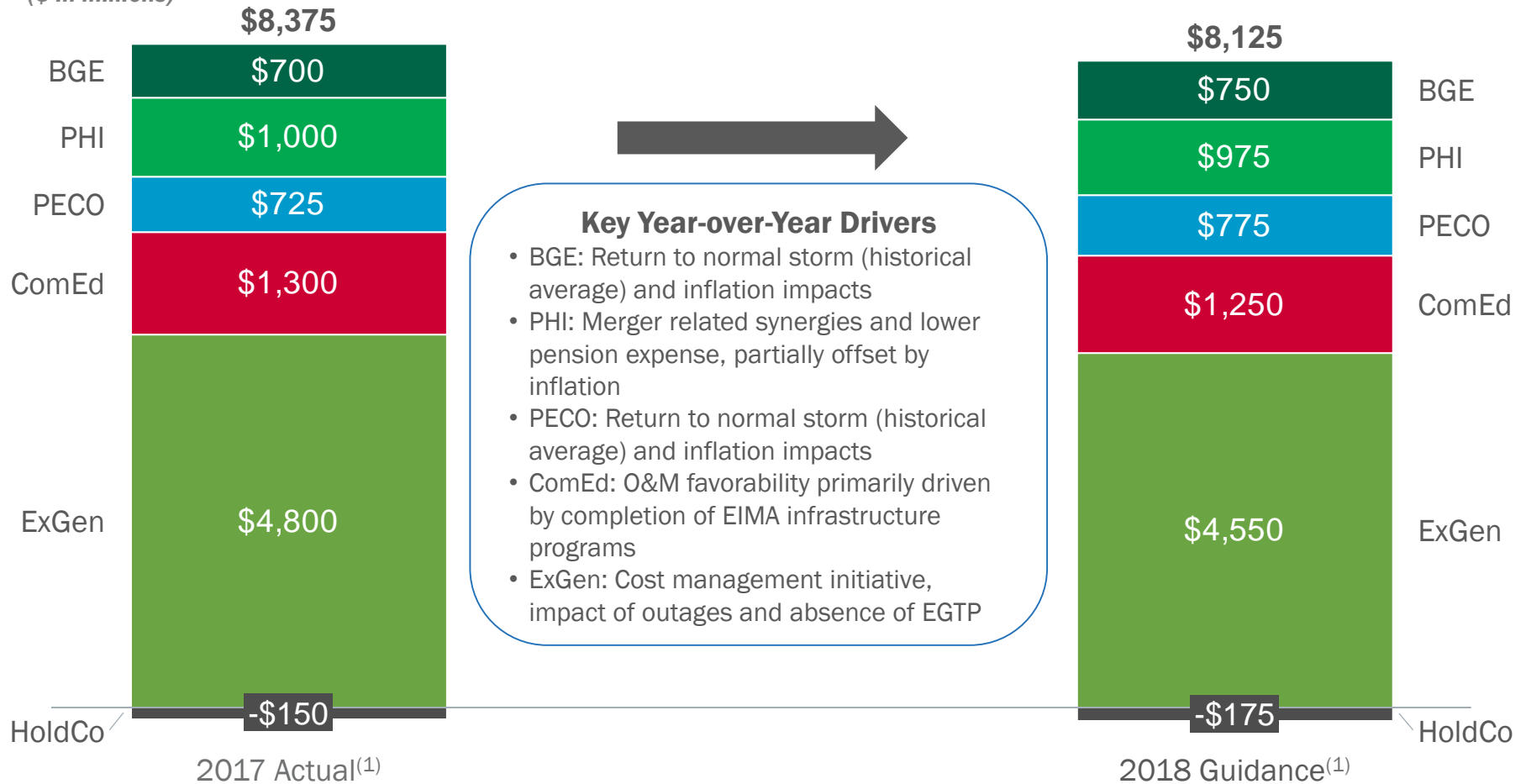
Capital and O&M now reflect removal of EGTP⁽⁴⁾, Oyster Creek, and TMI

- (1) O&M and Capital Expenditures reflect removal of Oyster Creek and TMI in 2018 and 2019, respectively, and removal of EGTP in 2018 forward, adjusted for retaining Handley Generating Station
- (2) Capital spend represents cash CapEx with CENG at 100% and excludes merger commitments
- (3) 2018E growth capital expenditures reflects a ~\$175M shift of cash outlay from 2017A to 2018E related to the CCGT projects in Texas
- (4) Adjusted for retaining Handley Generating Station

Adjusted O&M* Forecast

- Expect Compound Annual Growth Rate of **-1.1%** for 2018-2021

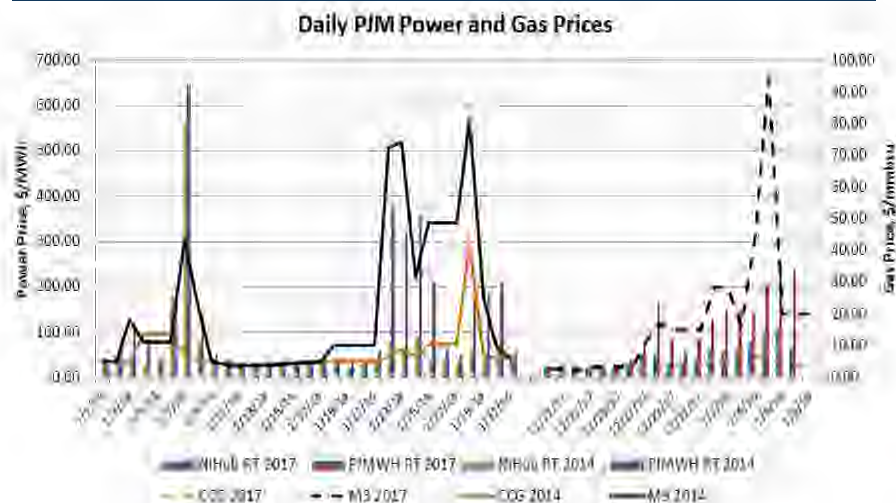
(\$ in millions)



(1) All amounts rounded to the nearest \$25M and may not add due to rounding

Comparing Winter 2017/2018 and the 2014 Polar Vortex

2014 Polar Vortex vs. 2017/2018 Winter

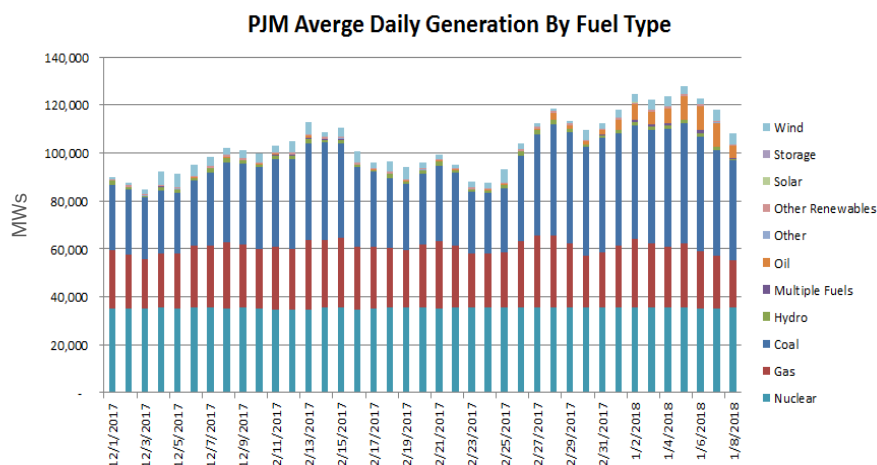


Generation Forced Outages⁽¹⁾

Fuel Type	Polar Vortex 1/7/2014		Winter 2017/2018			
	MW	%	1/5/2018		1/6/2018	
Coal	13,700	34%	5,849	35%	7,095	31%
Gas-Plant	9,700	24%	6,590	40%	9,220	40%
Gas-Supply	9,300	23%	2,181	13%	3,143	14%
Nuclear	1,400	3%	0	0%	0	0%
Oil			1,273	8%	1,991	9%
Other	6,100	15%	778	5%	1,457	6%
	40,200		16,671		22,906	

+23,000MW
Improvement

Generation Fuel Mix (MW)⁽²⁾



Key Takeaways

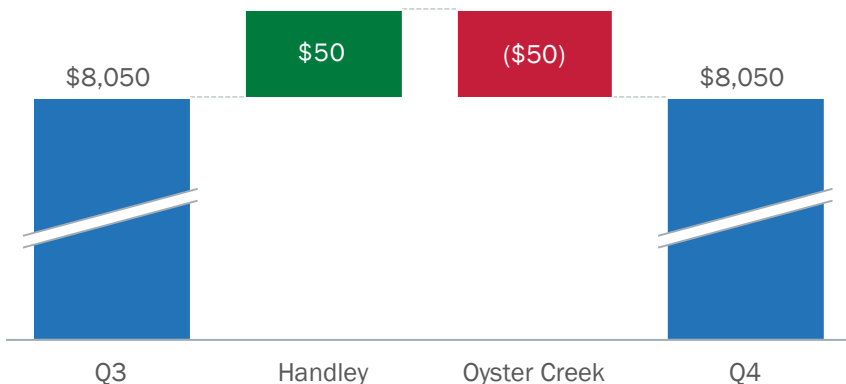
- PJM power prices cleared at times over ~\$200/MWh during the 2017/2018 winter, but were not as high as during the 2014 Polar Vortex
- Gas prices, while strong, were also not as high as polar vortex
- Unplanned outages during the 2017/2018 winter were much lower than experienced during the Polar Vortex, in part reflecting the benefits of improved reliability associated with the capacity performance improvements
- On the days with the highest gas prices, oil units ran and replaced eastern gas units

(1) Source: PJM Cold Weather Summary report, dated January 9, 2018

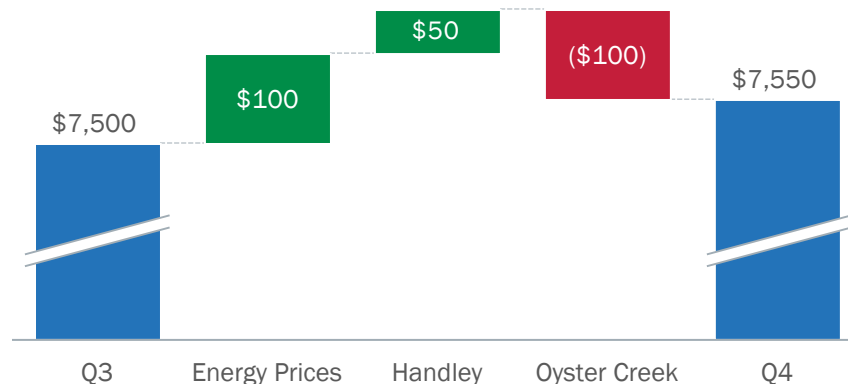
(2) Source: PJM

ExGen Forward Total Gross Margin* Walk: Q4 2017 vs. Q3 2017

FY 2018 (\$M)^(1,3,4,5)



FY 2019 (\$M)^(1,3,4)



FY 2020 versus FY 2019 (\$M)^(1,3,4)



Key Takeaways

- In 2018, Total Gross Margin is flat compared to September 30, 2017, reflecting a \$50M increase from retention of Handley Generating Station, and \$50M decrease from the early retirement of Oyster Creek
 - Strong quarter executing on \$150M of power new business
- In 2019, total gross margin is up \$50M, reflecting \$100M increase on higher power prices and strengthening ERCOT spark spreads plus \$50M from additional generation from Handley, partially offset by the early retirement of Oyster Creek
- Relative to 2019, 2020 Total Gross Margin is lower by \$300M:
 - \$150M lower primarily driven by Open Gross Margin related to TMI retirement
 - \$150M lower Capacity revenues from lower PJM and NE capacity prices

(1) Gross margin categories rounded to nearest \$50M
 (2) Excludes EDF's equity ownership share of the CENG Joint Venture
 (3) Based on December 31, 2017, market conditions
 (4) Reflects Oyster Creek and TMI retirements in October 2018 and September 2019, respectively. EGTP removal impacts full year 2018, 2019, and 2020 and is adjusted for retaining Handley Generating Station.
 (5) 2018 includes \$150M of IL ZEC revenues associated with 2017 production

2018 Projected Sources and Uses of Cash

(\$M) ⁽¹⁾	BGE	ComEd	PECO	PHI	Total Utilities	ExGen	Corp ⁽⁸⁾	Exelon 2018E	Cash Balance
Beginning Cash Balance⁽²⁾									1,400
Adjusted Cash Flow from Operations ⁽²⁾	625	1,625	600	1,125	3,975	3,875	275	8,100	
Base CapEx and Nuclear Fuel ⁽³⁾	0	0	0	0	0	(2,000)	(25)	(2,025)	
Free Cash Flow*	625	1,625	600	1,125	3,975	1,875	225	6,075	
Debt Issuances	300	1,300	700	750	3,050	0	0	3,050	
Debt Retirements	0	(850)	(500)	(250)	(1,600)	0	0	(1,600)	
Project Financing	n/a	n/a	n/a	n/a	n/a	(100)	n/a	(100)	
Equity Issuance/Share Buyback	0	0	0	0	0	0	0	0	
Contribution from Parent	100	450	50	225	850	0	(850)	0	
Other Financing ⁽⁴⁾	175	300	25	(75)	425	(100)	(50)	275	
Financing⁽⁵⁾	600	1,200	275	650	2,725	(200)	(900)	1,625	
Total Free Cash Flow and Financing	1,200	2,850	875	1,775	6,700	1,675	(675)	7,700	
Utility Investment	(1,000)	(2,125)	(800)	(1,500)	(5,400)	0	0	(5,400)	
ExGen Growth ^(3,6)	0	0	0	0	0	(375)	0	(375)	
Acquisitions and Divestitures	0	0	0	0	0	0	0	0	
Equity Investments	0	0	0	0	0	(25)	0	(25)	
Dividend ⁽⁷⁾	0	0	0	0	0	0	(1,325)	(1,325)	
Other CapEx and Dividend	(1,000)	(2,125)	(800)	(1,500)	(5,400)	(400)	(1,325)	(7,125)	
Total Cash Flow	225	700	75	275	1,300	1,275	(2,000)	575	
Ending Cash Balance⁽²⁾									1,975

- (1) All amounts rounded to the nearest \$25M. Figures may not add due to rounding.
- (2) Gross of posted counterparty collateral
- (3) Figures reflect cash CapEx and CENG fleet at 100%
- (4) Other Financing primarily includes expected changes in money pool borrowings, tax sharing from the parent, debt issue costs, tax equity cash flows, capital leases, and renewable JV distributions
- (5) Financing cash flow excludes intercompany dividends and other intercompany financing activities
- (6) ExGen Growth CapEx primarily includes Texas CCGTs, W. Medway, and Retail Solar
- (7) Dividends are subject to declaration by the Board of Directors
- (8) Includes cash flow activity from Holding Company, eliminations, and other corporate entities

Consistent and reliable free cash flows

Operational excellence and financial discipline drives free cash flow reliability

- ✓ Generating \$6.1B of free cash flow, including \$1.9B at ExGen and \$4.0B at the Utilities

Supported by a strong balance sheet

Strong balance sheet enables flexibility to raise and deploy capital for growth

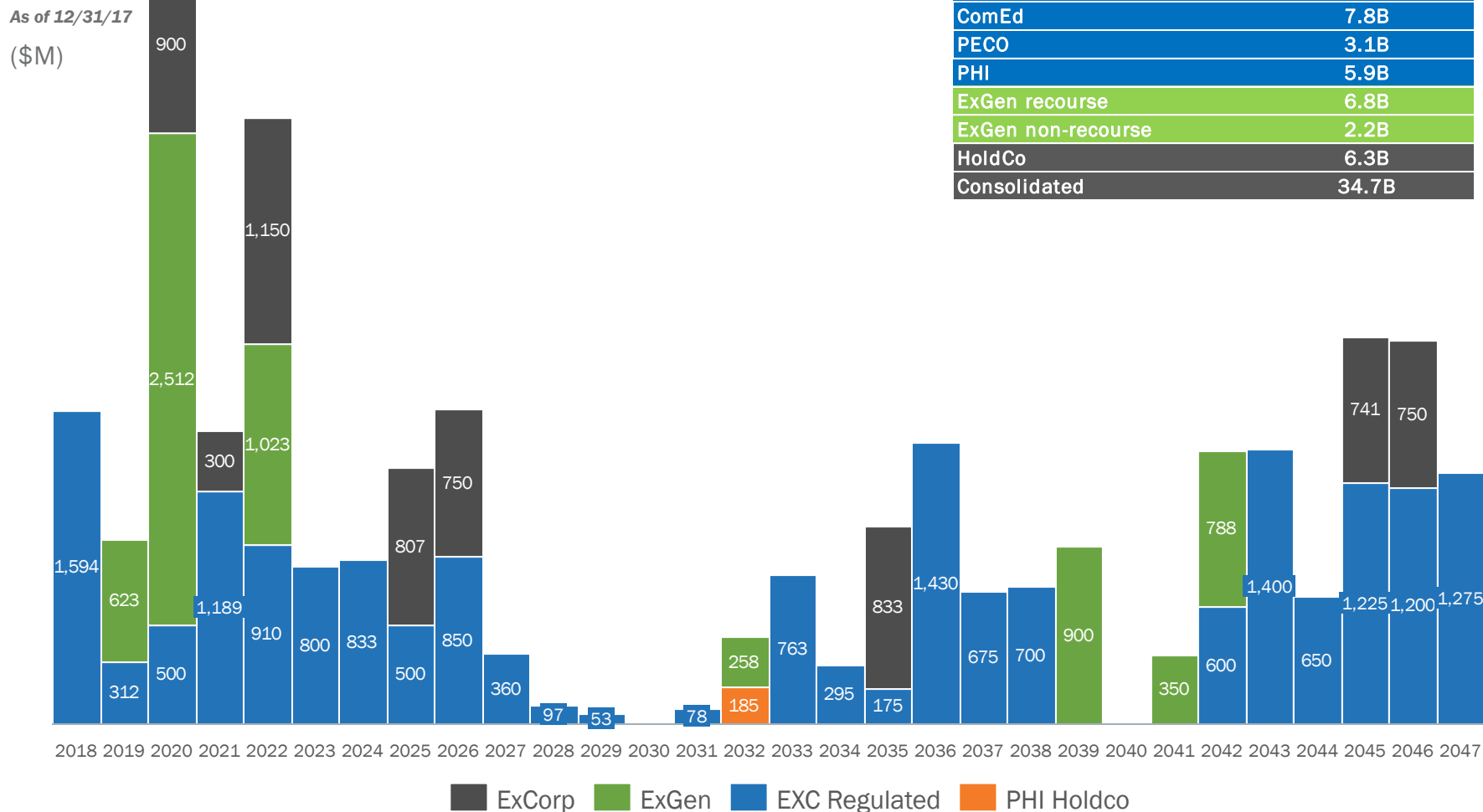
- ✓ \$1.4B of long-term debt at the utilities, net of refinancing, to support continued growth

Enable growth & value creation

Creating value for customers, communities and shareholders

- ✓ Investing \$5.8B of growth capex, with \$5.4B at the Utilities and \$0.4B at ExGen

Exelon Debt Maturity Profile⁽¹⁾



Exelon's weighted average LTD maturity is approximately 13 years

- (1) Maturity profile excludes non-recourse debt, securitized debt, capital leases, fair value adjustments, unamortized debt issuance costs and unamortized discount/premium
 (2) Long-term debt balances reflect 2017 10-K GAAP financials; ExGen debt includes legacy CEG debt

Pension and OPEB Contributions and Expense

	2017		2018	
(in \$M)	Pre-Tax Expense ⁽¹⁾	Contributions	Pre-Tax Expense (Benefit) ⁽¹⁾	Contributions
Qualified Pension (2) (3) (4)	\$445	\$315	\$420	\$300
Non-Qualified Pension	20	25	25	30
OPEB ⁽³⁾⁽⁴⁾	-	65	(5)	45
Total	\$465	\$405	\$440	\$375

(1) Pension and OPEB expenses assume a 30% and 25% capitalization rate in 2017 and 2018, respectively

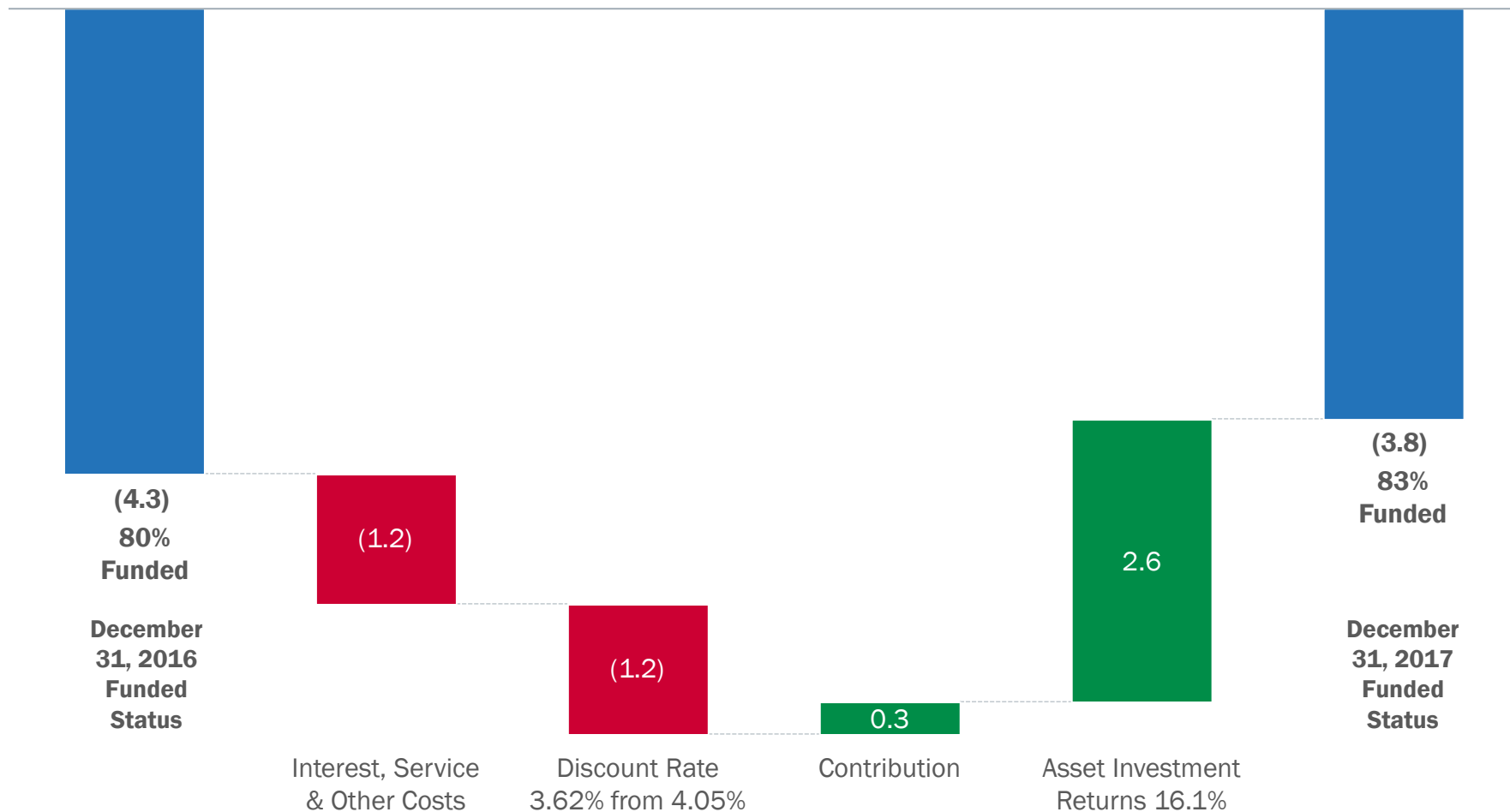
(2) The Balanced Funding Strategy for the Qualified Plans provides pension funding of the greater of \$250M or minimum required contributions plus amounts required to avoid benefit restrictions and at-risk status for the legacy Exelon plans. PHI qualified plan contributions were \$60M in 2017 and are expected to be \$50M in 2018.

(3) Expected return on pension and OPEB plan assets is 7.00% and 6.60%, respectively, for both 2017 and 2018

(4) The discount rates used to determine costs for the majority of Exelon's pension and OPEB plans were 4.04% and 3.62% for 2017 and 2018, respectively

Pension – Funded Status and Performance

Pension 2017 Funded Status (PBO) Comparison (\$B)



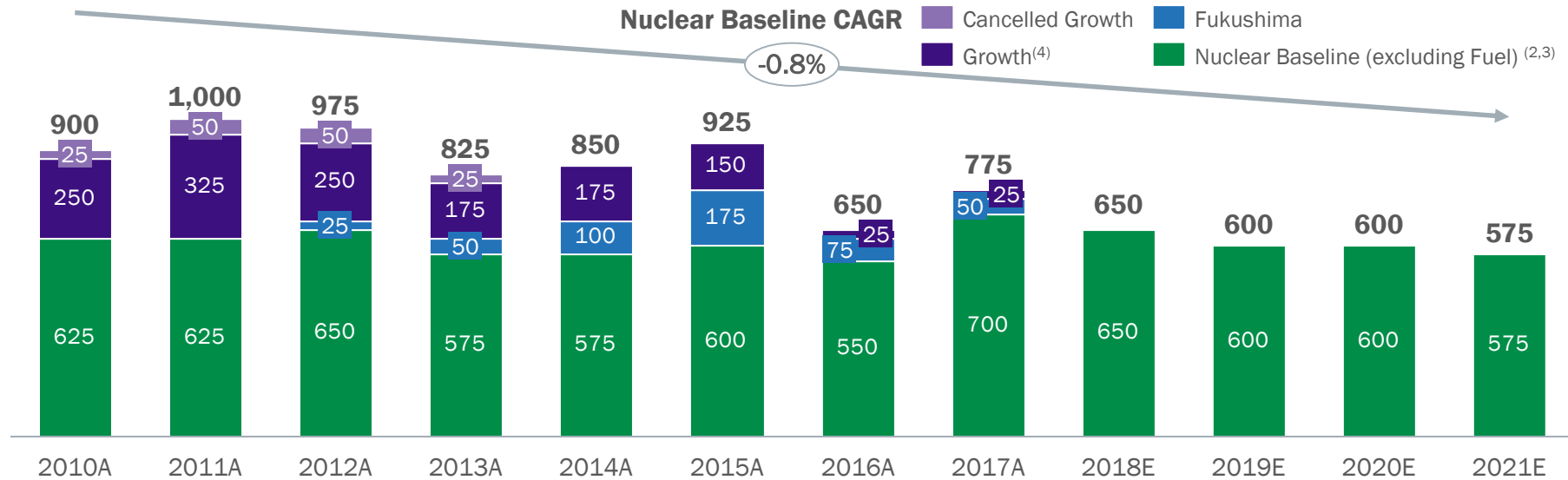
EPS Sensitivities

	<u>2018</u>	<u>2019</u>	<u>2020</u>	
ExGen EPS Impact* (1)	Henry Hub Natural Gas			
	+ \$1/MMBtu	\$0.15	\$0.32	\$0.50
	- \$1/MMBtu	(\$0.15)	(\$0.31)	(\$0.47)
	NiHub ATC Energy Price			
	+ \$5/MWh	\$0.06	\$0.16	\$0.26
	- \$5/MWh	(\$0.05)	(\$0.16)	(\$0.26)
	PJM-W ATC Energy Price			
	+ \$5/MWh	\$0.02	\$0.08	\$0.13
- \$5/MWh	(\$0.01)	(\$0.07)	(\$0.12)	
Interest Rate Sensitivity to +50 BP	ComEd ROE	\$0.03	\$0.03	\$0.04
	Pension Expense	-	\$0.03	\$0.03
	Cost of Debt	(\$0.00)	(\$0.00)	(\$0.01)
Share count (millions)		969	972	975
Exelon Consolidated Effective Tax Rate		18%	19%	20%

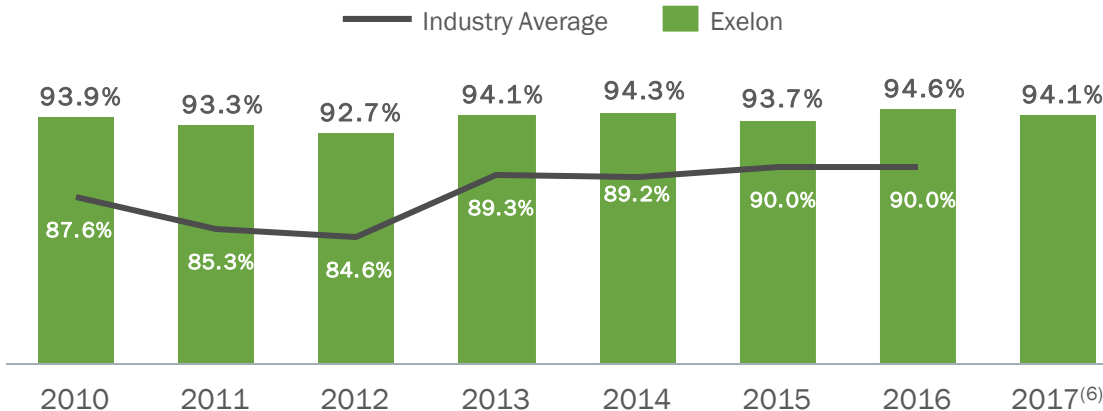
(1) Based on December 31, 2017, market conditions and hedged position. Gas price sensitivities are based on an assumed gas-power relationship derived from an internal model that is updated periodically. Power price sensitivities are derived by adjusting the power price assumption while keeping all other price inputs constant. Due to correlation of the various assumptions, the EPS impact calculated by aggregating individual sensitivities may not be equal to the EPS impact calculated when correlations between the various assumptions are also considered.

Historical Nuclear Capital Investment

Nuclear Non-Fuel Capital Expenditures⁽¹⁾ (\$M)



Nuclear Capacity Factor⁽⁵⁾



Significant historical investments have mitigated asset management issues and prepared sites for license extensions already received, reducing future capital needs. In addition, internal cost initiatives have found more cost efficient solutions to large CapEx spend, such as leveraging reverse engineering replacements rather than large system wide modifications, resulting in baseline CAGR of -0.8%, even with net addition of 2 sites.

- (1) Reflects accrual capital expenditures with CENG at 50% ownership. Assumes Oyster Creek and TMI retirements in October 2018 and September 2019, respectively. All numbers rounded to \$25M.
 (2) Baseline includes ownership share of Salem all years. CENG is included at ownership share starting in 2014 (full year)
 (3) FitzPatrick included starting in 2017 (9 months only)
 (4) Growth represents capital that increases the capacity of the units (e.g., turbine upgrades, power uprates), and capital that extends the license of a site (e.g., License Renewals)
 (5) Includes CENG beginning in April 2014 and FitzPatrick beginning in April of 2017, excludes Salem and Fort Calhoun
 (6) 2017 industry average excluding Exelon was not available at time of publication

2017 Exelon Recognition and Partnerships

Sustainability



Dow Jones Sustainability Index

Exelon named to Dow Jones Sustainability Index for 12th consecutive year



Newsweek Magazine's Green Rankings

Newsweek Magazine's Green Rankings recognized our leadership in sustainability, where we ranked third among utilities, No. 12 in the U.S. 500 and 24th among the Global 500



Carbon Reduction

A recent U.S. Environmental Protection Agency report noted Exelon's generation fleet had the lowest rate of emissions among the 20 largest public or privately held energy producers. Fortune also recognized Exelon as the second-lowest carbon emitter of all Fortune 100 companies



Land for People Award

Received the Trust for Public Land's national "Land for People Award" in recognition of Exelon's deep support of environmental stewardship, creating new parks and promoting conservation

Corporate & Foundation Giving



\$52.1 million

Last year, Exelon and its employees set all-time records, committing more than \$52.1 million to non-profit organizations and volunteering more than 210,000 hours



Civic 50

Exelon was named for the first time to the Civic 50, recognizing the most community-minded companies by Points of Light, the world's largest organization dedicated to volunteer service

Corporate Recognition



2017 Laurie D. Zelon Pro Bono Award

For exemplary pro bono service and leadership



Kids in Need of Defense Innovation Award

Exelon's legal department and the Baltimore chapter of Organization of Latinos at Exelon (OLE) for their work with unaccompanied minors from Central America

Diversity & Inclusion



HeForShe

Exelon joined U.N. Women's HeForShe campaign, which is focused on gender equality. Pledge includes a \$3 million commitment to develop new STEM programs for girls and young women and improving the retention of women at Exelon by 2020



Billion Dollar Roundtable

Exelon became the first energy company to join the Billion Dollar Roundtable, an organization that promotes supplier diversity for corporations achieving \$1 billion or more in annual direct spending with minority and women-owned businesses



CEO Action for Diversity & Inclusion

Exelon joined 150 leading companies for the CEO Action for Diversity & Inclusion™, the largest CEO-driven commitment aimed at taking action to cultivate a workplace where diverse perspectives and experiences are welcomed and respected

Workforce



DiversityInc Top 50

DiversityInc. named Exelon as one of the Top 50 companies for excellence in diversity.



Indeed.com "50 Best Places to Work"

Indeed.com ranked Exelon No. 18 on its "50 Best Places to Work."



Human Rights Campaign "Best Places to Work" For the third consecutive year, HRC's Corporate Equality Index gave Exelon a perfect rating on its best places to work for LGBTQ



2017 U.S. Veterans Magazine's "Best of the Best"

Most veteran-friendly companies



Historically Black Engineering Schools

Top Supporter recognition for five consecutive years

Exelon Generation Disclosures

December 31, 2017

Portfolio Management Strategy

Strategic Policy Alignment

- Aligns hedging program with financial policies and financial outlook
- Establish minimum hedge targets to meet financial objectives of the company (dividend, credit rating)
- Hedge enough commodity risk to meet future cash requirements under a stress scenario

Three-Year Ratable Hedging

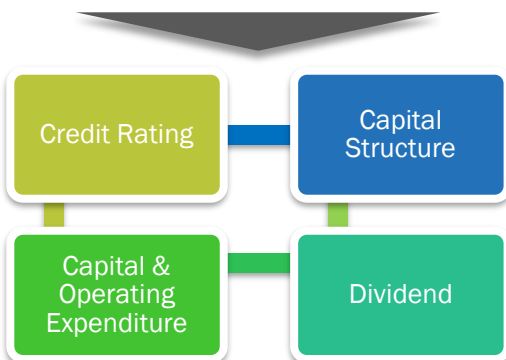
- Ensure stability in near-term cash flows and earnings
- Disciplined approach to hedging
- Tenor aligns with customer preferences and market liquidity
- Multiple channels to market that allow us to maximize margins
- Large open position in outer years to benefit from price upside

Bull / Bear Program

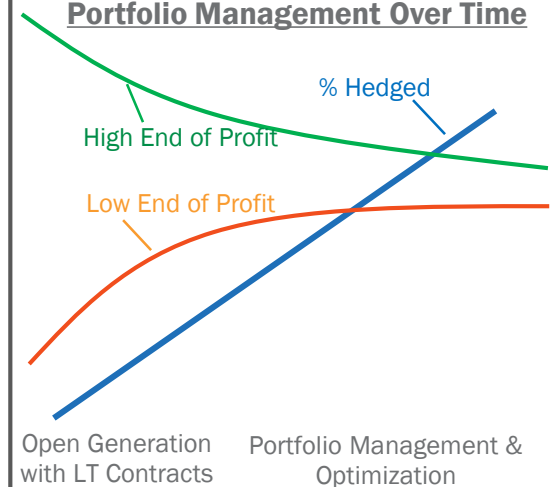
- Ability to exercise fundamental market views to create value within the ratable framework
- Modified timing of hedges versus purely ratable
- Cross-commodity hedging (heat rate positions, options, etc.)
- Delivery locations, regional and zonal spread relationships

Align Hedging & Financials

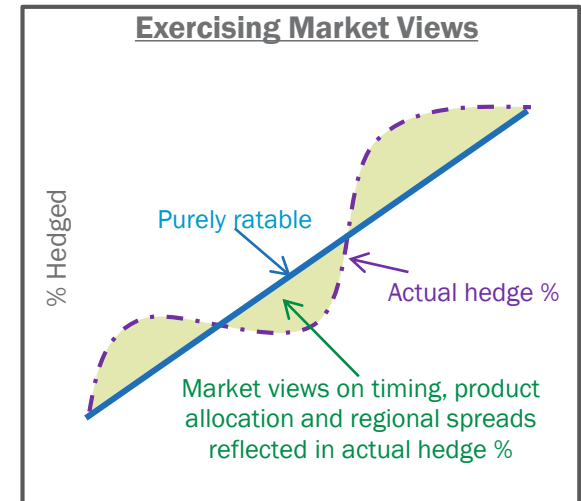
Establishing Minimum Hedge Targets



Portfolio Management Over Time



Exercising Market Views



Protect Balance Sheet

Ensure Earnings Stability

Create Value

Components of Gross Margin Categories

Gross margin linked to power production and sales

Open Gross Margin

- Generation Gross Margin at current market prices, including ancillary revenues, nuclear fuel amortization and fossils fuels expense
- Power Purchase Agreement (PPA) Costs and Revenues
- Provided at a consolidated level for all regions (includes hedged gross margin for South, West and Canada⁽¹⁾)

Capacity and ZEC Revenues

- Expected capacity revenues for generation of electricity
- Expected revenues from Zero Emissions Credits (ZEC)

MtM of Hedges⁽²⁾

- Mark-to-Market (MtM) of power, capacity and ancillary hedges, including cross commodity, retail and wholesale load transactions
- Provided directly at a consolidated level for five major regions. Provided indirectly for each of the five major regions via Effective Realized Energy Price (EREP), reference price, hedge %, expected generation.

“Power” New Business

- Retail, Wholesale planned electric sales
- Portfolio Management new business
- Mid marketing new business

Margins move from new business to MtM of hedges over the course of the year as sales are executed⁽⁵⁾

Gross margin from other business activities

“Non Power” Executed

- Retail, Wholesale executed gas sales
- Energy Efficiency⁽⁴⁾
- BGE Home⁽⁴⁾
- Distributed Solar

“Non Power” New Business

- Retail, Wholesale planned gas sales
- Energy Efficiency⁽⁴⁾
- BGE Home⁽⁴⁾
- Distributed Solar
- Portfolio Management / origination fuels new business
- Proprietary trading⁽³⁾

Margins move from “Non power new business” to “Non power executed” over the course of the year

(1) Hedged gross margins for South, West & Canada region will be included with Open Gross Margin; no expected generation, hedge %, EREP or reference prices provided for this region

(2) MtM of hedges provided directly for the five larger regions; MtM of hedges is not provided directly at the regional level but can be easily estimated using EREP, reference price and hedged MWh

(3) Proprietary trading gross margins will generally remain within “Non Power” New Business category and only move to “Non Power” Executed category upon management discretion

(4) Gross margin for these businesses are net of direct “cost of sales”

(5) Margins for South, West & Canada regions and optimization of fuel and PPA activities captured in Open Gross Margin

ExGen Disclosures

Gross Margin Category (\$M) ⁽¹⁾	2018	2019	2020
Open Gross Margin (including South, West & Canada hedged GM) ^(2,5)	\$4,350	\$3,900	\$3,750
Capacity and ZEC Revenues ^(2,5,6)	\$2,300	\$2,000	\$1,850
Mark-to-Market of Hedges ^(2,3)	\$350	\$400	\$250
Power New Business / To Go	\$550	\$750	\$900
Non-Power Margins Executed	\$200	\$100	\$100
Non-Power New Business / To Go	\$300	\$400	\$400
Total Gross Margin*^(4,5)	\$8,050	\$7,550	\$7,250

Reference Prices ⁽⁴⁾	2018	2019	2020
Henry Hub Natural Gas (\$/MMBtu)	\$2.83	\$2.81	\$2.82
Midwest: NiHub ATC prices (\$/MWh)	\$27.93	\$26.94	\$26.91
Mid-Atlantic: PJM-W ATC prices (\$/MWh)	\$33.51	\$30.72	\$30.12
ERCOT-N ATC Spark Spread (\$/MWh) <i>HSC Gas, 7.2HR, \$2.50 VOM</i>	\$6.21	\$5.85	\$5.30
New York: NY Zone A (\$/MWh)	\$29.14	\$26.15	\$25.48
New England: Mass Hub ATC Spark Spread (\$/MWh) <i>ALQN Gas, 7.5HR, \$0.50 VOM</i>	\$5.84	\$5.10	\$5.63

(1) Gross margin categories rounded to nearest \$50M

(2) Excludes EDF's equity ownership share of the CENG Joint Venture

(3) Mark-to-Market of Hedges assumes mid-point of hedge percentages

(4) Based on December 31, 2017, market conditions

(5) Reflects Oyster Creek and TMI retirements in October 2018 and September 2019, respectively. EGTP removal impacts full year 2018, 2019, and 2020 and is adjusted for removal of Handley Generating Station.

(6) 2018 includes \$150M of IL ZEC revenues associated with 2017 production

ExGen Disclosures

Generation and Hedges	2018	2019	2020
<u>Exp. Gen (GWh)⁽¹⁾</u>	201,500	201,200	191,400
Midwest	95,900	97,200	96,700
Mid-Atlantic ^(2,6)	59,600	54,200	48,600
ERCOT	24,200	24,500	22,000
New York ^(2,6)	15,400	16,600	15,500
New England	6,400	8,700	8,600
<u>% of Expected Generation Hedged⁽³⁾</u>	85%-88%	55%-58%	26%-29%
Midwest	82%-85%	51%-54%	22%-25%
Mid-Atlantic ^(2,6)	88%-91%	65%-68%	33%-36%
ERCOT	81%-84%	54%-57%	26%-29%
New York ^(2,6)	94%-97%	57%-60%	26%-29%
New England	92%-95%	35%-38%	38%-41%
<u>Effective Realized Energy Price (\$/MWh)⁽⁴⁾</u>			
Midwest	\$29.50	\$29.50	\$31.00
Mid-Atlantic ^(2,6)	\$36.00	\$37.50	\$38.50
ERCOT ⁽⁵⁾	\$4.50	\$3.50	\$2.00
New York ^(2,6)	\$36.00	\$32.00	\$30.00
New England ⁽⁵⁾	\$1.00	\$5.00	\$9.00

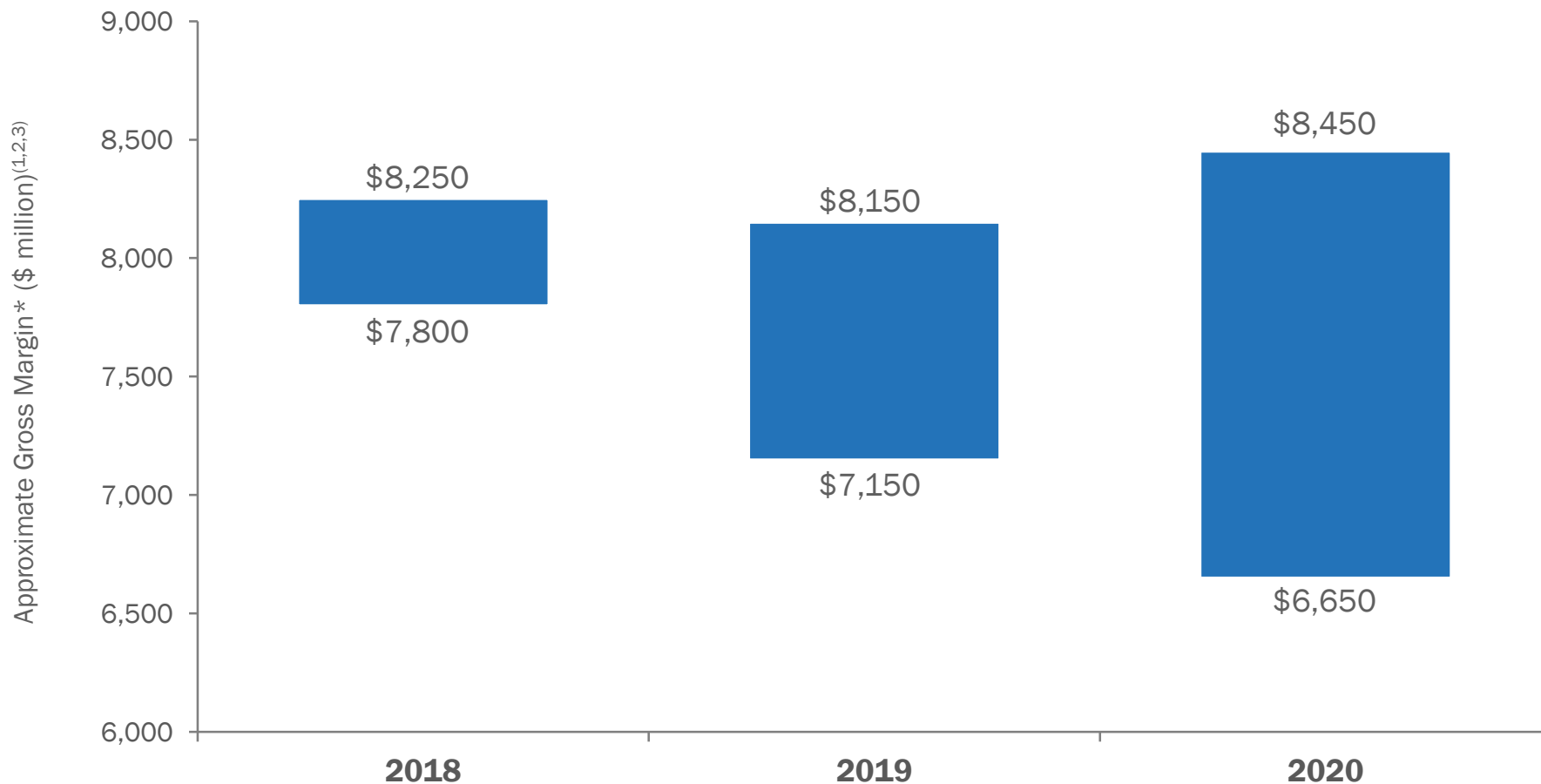
- (1) Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Expected generation assumes 14 refueling outages in 2018, 11 in 2019, and 14 in 2020 at Exelon-operated nuclear plants and Salem. Expected generation assumes capacity factors of 93.4%, 94.9% and 93.9% in 2018, 2019, and 2020, respectively at Exelon-operated nuclear plants, at ownership. These estimates of expected generation in 2019 and 2020 do not represent guidance or a forecast of future results as Exelon has not completed its planning or optimization processes for those years.
- (2) Excludes EDF's equity ownership share of CENG Joint Venture
- (3) Percent of expected generation hedged is the amount of equivalent sales divided by expected generation. Includes all hedging products, such as wholesale and retail sales of power, options and swaps.
- (4) Effective realized energy price is representative of an all-in hedged price, on a per MWh basis, at which expected generation has been hedged. It is developed by considering the energy revenues and costs associated with our hedges and by considering the fossil fuel that has been purchased to lock in margin. It excludes uranium costs, RPM capacity and ZEC revenues, but includes the mark-to-market value of capacity contracted at prices other than RPM clearing prices including our load obligations. It can be compared with the reference prices used to calculate open gross margin in order to determine the mark-to-market value of Exelon Generation's energy hedges.
- (5) Spark spreads shown for ERCOT and New England
- (6) Reflects Oyster Creek and TMI retirements in October 2018 and September 2019, respectively. EGTP removal impacts full year 2018, 2019, and 2020 and is adjusted for retaining Handley Generating Station.

ExGen Hedged Gross Margin* Sensitivities

Gross Margin* Sensitivities (with existing hedges) ⁽¹⁾	2018	2019	2020
Henry Hub Natural Gas (\$/MMBtu)			
+ \$1/MMBtu	\$190	\$410	\$645
- \$1/MMBtu	\$(190)	\$(400)	\$(615)
NiHub ATC Energy Price			
+ \$5/MWh	\$75	\$210	\$345
- \$5/MWh	\$(70)	\$(210)	\$(340)
PJM-W ATC Energy Price			
+ \$5/MWh	\$30	\$100	\$165
- \$5/MWh	\$(15)	\$(90)	\$(160)
NYPP Zone A ATC Energy Price			
+ \$5/MWh	-	\$30	\$55
- \$5/MWh	-	\$(35)	\$(55)
Nuclear Capacity Factor			
+/- 1%	+/- \$40	+/- \$35	+/- \$35

(1) Based on December 31, 2017, market conditions and hedged position; gas price sensitivities are based on an assumed gas-power relationship derived from an internal model that is updated periodically; power price sensitivities are derived by adjusting the power price assumption while keeping all other price inputs constant; due to correlation of the various assumptions, the hedged gross margin impact calculated by aggregating individual sensitivities may not be equal to the hedged gross margin impact calculated when correlations between the various assumptions are also considered; sensitivities based on commodity exposure which includes open generation and all committed transactions; excludes EDF's equity share of CENG Joint Venture

ExGen Hedged Gross Margin* Upside/Risk



- (1) Represents an approximate range of expected gross margin, taking into account hedges in place, between the 5th and 95th percent confidence levels assuming all unhedged supply is sold into the spot market; approximate gross margin ranges are based upon an internal simulation model and are subject to change based upon market inputs, future transactions and potential modeling changes; these ranges of approximate gross margin in 2019 and 2020 do not represent earnings guidance or a forecast of future results as Exelon has not completed its planning or optimization processes for those years; the price distributions that generate this range are calibrated to market quotes for power, fuel, load following products, and options as of December 31, 2017
- (2) Gross Margin Upside/Risk based on commodity exposure which includes open generation and all committed transactions
- (3) Reflects Oyster Creek and TMI retirements in October 2018 and September 2019, respectively. EGTP removal impacts full year 2018, 2019, and 2020 and is adjusted for retaining Handley Generating Station.

Illustrative Example of Modeling Exelon Generation 2019 Gross Margin*

ZECJ-FIN-21

PUBLIC

Row	Item	Midwest	Mid-Atlantic	ERCOT	New York	New England	South, West & Canada
(A)	Start with fleet-wide open gross margin	 \$3.9 billion					
(B)	Capacity and ZEC	 \$2 billion					
(C)	Expected Generation (TWh)	97.2	54.2	24.5	16.6	8.7	
(D)	Hedge % (assuming mid-point of range)	52.5%	66.5%	55.5%	58.5%	36.5%	
(E=C*D)	Hedged Volume (TWh)	51.0	36.0	13.6	9.7	3.2	
(F)	Effective Realized Energy Price (\$/MWh)	\$29.50	\$37.50	\$3.50	\$32.00	\$5.00	
(G)	Reference Price (\$/MWh)	\$26.94	\$30.72	\$5.85	\$26.15	\$5.10	
(H=F-G)	Difference (\$/MWh)	\$2.56	\$6.78	(\$2.35)	\$5.85	(\$0.10)	
(I=E*H)	Mark-to-Market value of hedges (\$ million) ⁽¹⁾	\$130	\$245	(\$30)	\$55	\$0	
(J=A+B+I)	Hedged Gross Margin (\$ million)	\$6,300					
(K)	Power New Business / To Go (\$ million)	\$750					
(L)	Non-Power Margins Executed (\$ million)	\$100					
(M)	Non-Power New Business / To Go (\$ million)	\$400					
(N=J+K+L+M)	Total Gross Margin*	\$7,550 million					

(1) Mark-to-market rounded to the nearest \$5 million

Additional ExGen Modeling Data

Total Gross Margin Reconciliation (in \$M) ⁽¹⁾	2018	2019	2020
Revenue Net of Purchased Power and Fuel Expense ^{*(2,3)}	\$8,500	\$8,025	\$7,700
Non-cash amortization of intangible assets, net, related to commodity contracts recorded at fair value at merger date	-	-	-
Other Revenues ⁽⁴⁾	\$(200)	\$(175)	\$(200)
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses	\$(250)	\$(300)	\$(250)
Total Gross Margin* (Non-GAAP)	\$8,050	\$7,550	\$7,250

Key ExGen Modeling Inputs (in \$M) ^(1,5)	2018
Other ⁽⁶⁾	\$150
Adjusted O&M*	\$(4,550)
Taxes Other Than Income (TOTI) ⁽⁷⁾	\$(375)
Depreciation & Amortization ⁽⁸⁾	\$(1,125)
Interest Expense	\$(400)
Effective Tax Rate	22.0%

(1) All amounts rounded to the nearest \$25M

(2) ExGen does not forecast the GAAP components of RNF separately, as to do so would be unduly burdensome. RNF also includes the RNF of our proportionate ownership share of CENG.

(3) Excludes the Mark-to-Market impact of economic hedging activities due to the volatility and unpredictability of the future changes to power prices

(4) Other Revenues reflects primarily revenues from Exelon Nuclear Partners, JExel Nuclear JV, variable interest entities, funds collected through revenues for decommissioning the former PECO nuclear plants through regulated rates, and gross receipts tax revenues

(5) ExGen amounts for O&M, TOTI, Depreciation & Amortization; excludes EDF's equity ownership share of the CENG Joint Venture

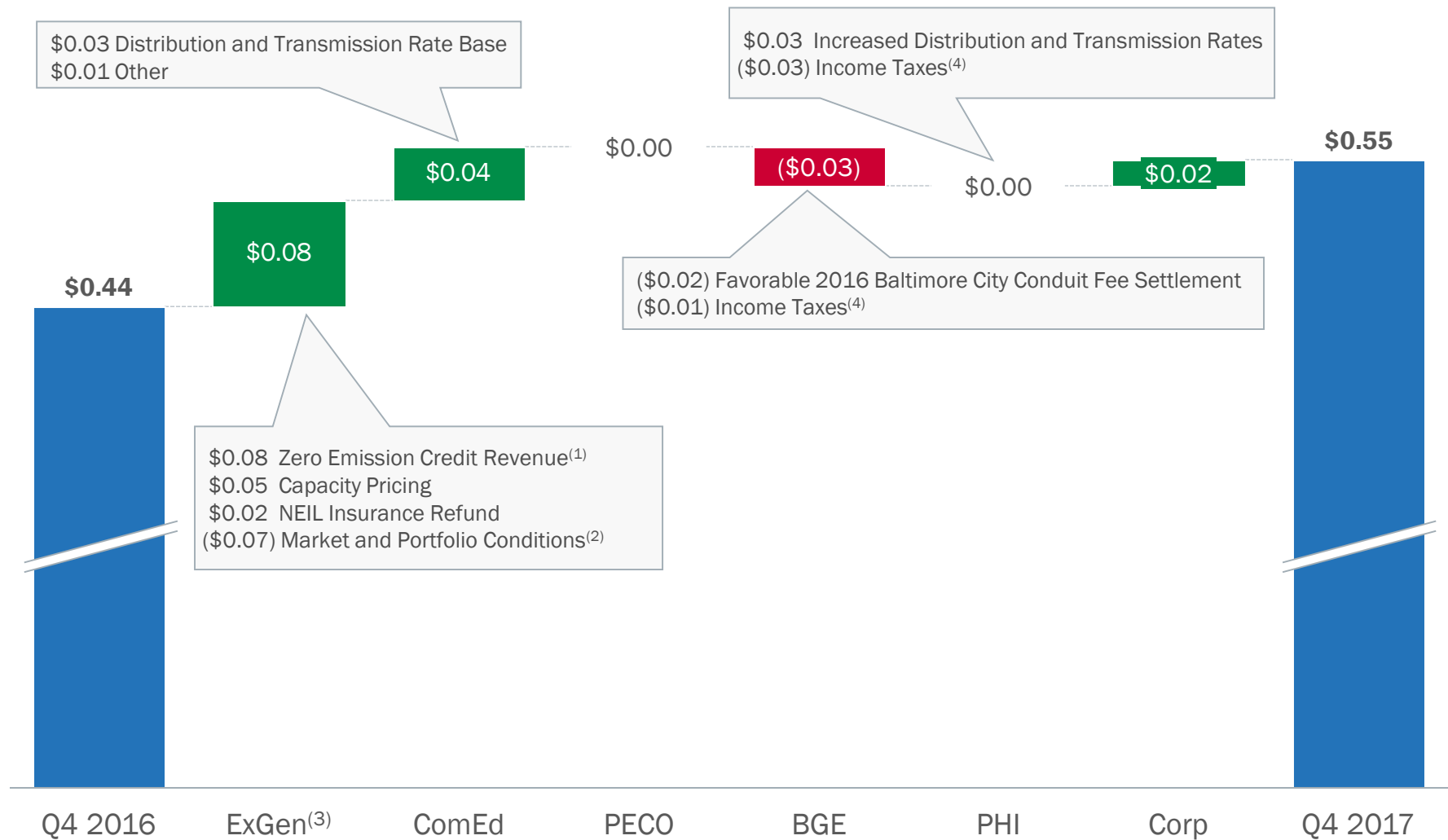
(6) Other reflects Other Revenues excluding gross receipts tax revenues, and includes nuclear decommissioning trust fund earnings from unregulated sites, and the minority interest in ExGen Renewables JV and Bloom

(7) TOTI excludes gross receipts tax of \$150M

(8) 2019 Depreciation & Amortization is flat to 2018 and 2020 is favorable \$50M due to nuclear plant retirements

2017A Earnings Waterfalls

QTD Adjusted Operating Earnings* Waterfall



Note: Amounts may not sum due to rounding

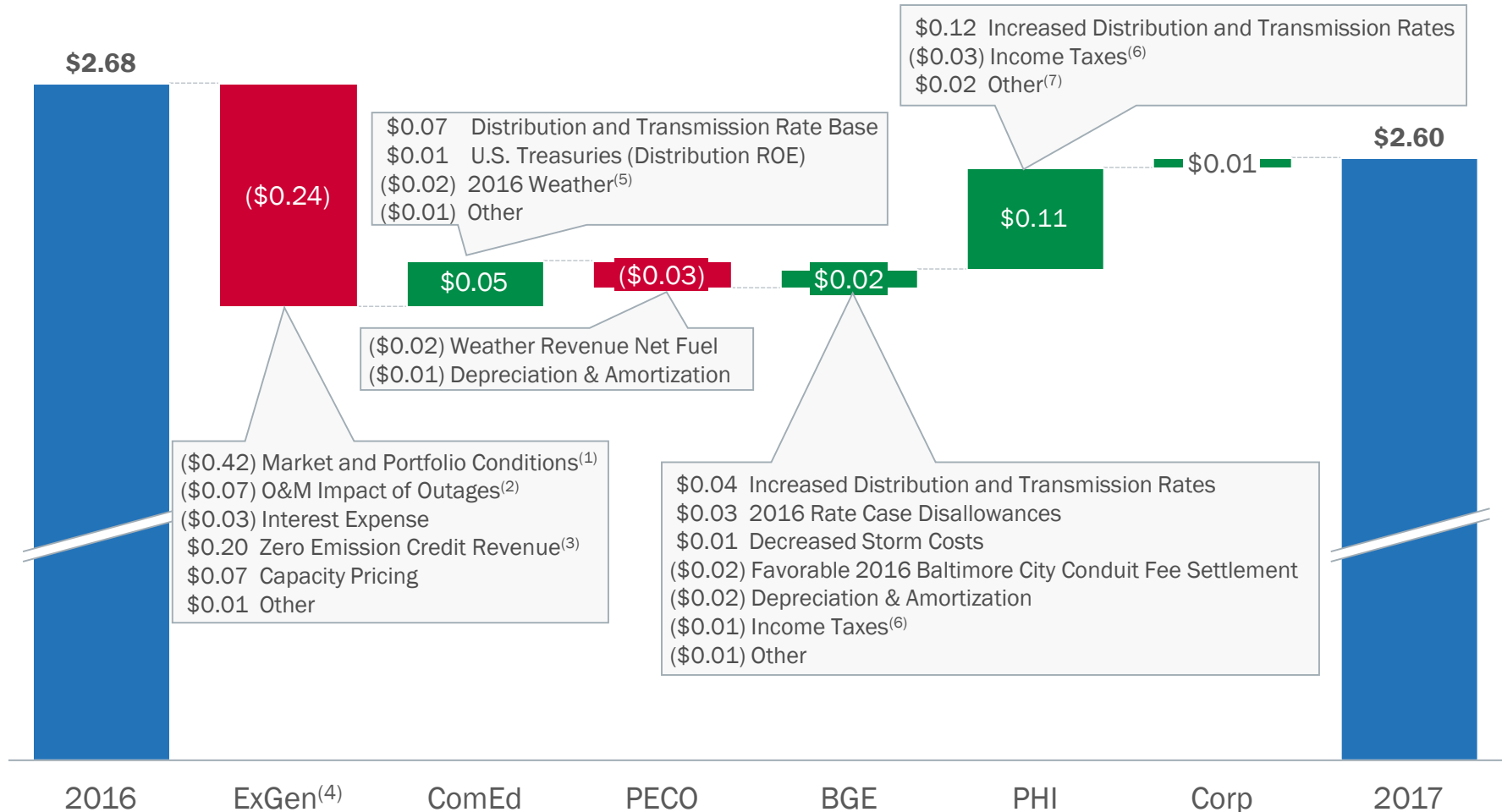
(1) Reflects the impact of the New York ZECs

(2) Includes the unfavorable impact of lower realized energy prices and the conclusion of the Ginna Reliability Support Services Agreement

(3) Reflects CENG ownership at 100%

(4) Reflects a 2017 impairment of certain transmission-related income tax regulatory assets

FY Adjusted Operating Earnings* Waterfall



Note: Amounts may not sum due to rounding

(1) Includes the unfavorable impact of lower realized energy prices, the impacts of lower load volumes delivered due to mild weather in the third quarter 2017, the conclusion of the Ginna Reliability Support Services Agreement and the impact of declining natural gas prices on Generation's natural gas portfolio

(2) Driven by higher planned nuclear outage days in 2017; excludes Salem

(3) Reflects the impact of the New York ZECs

(4) Reflects CENG ownership at 100%

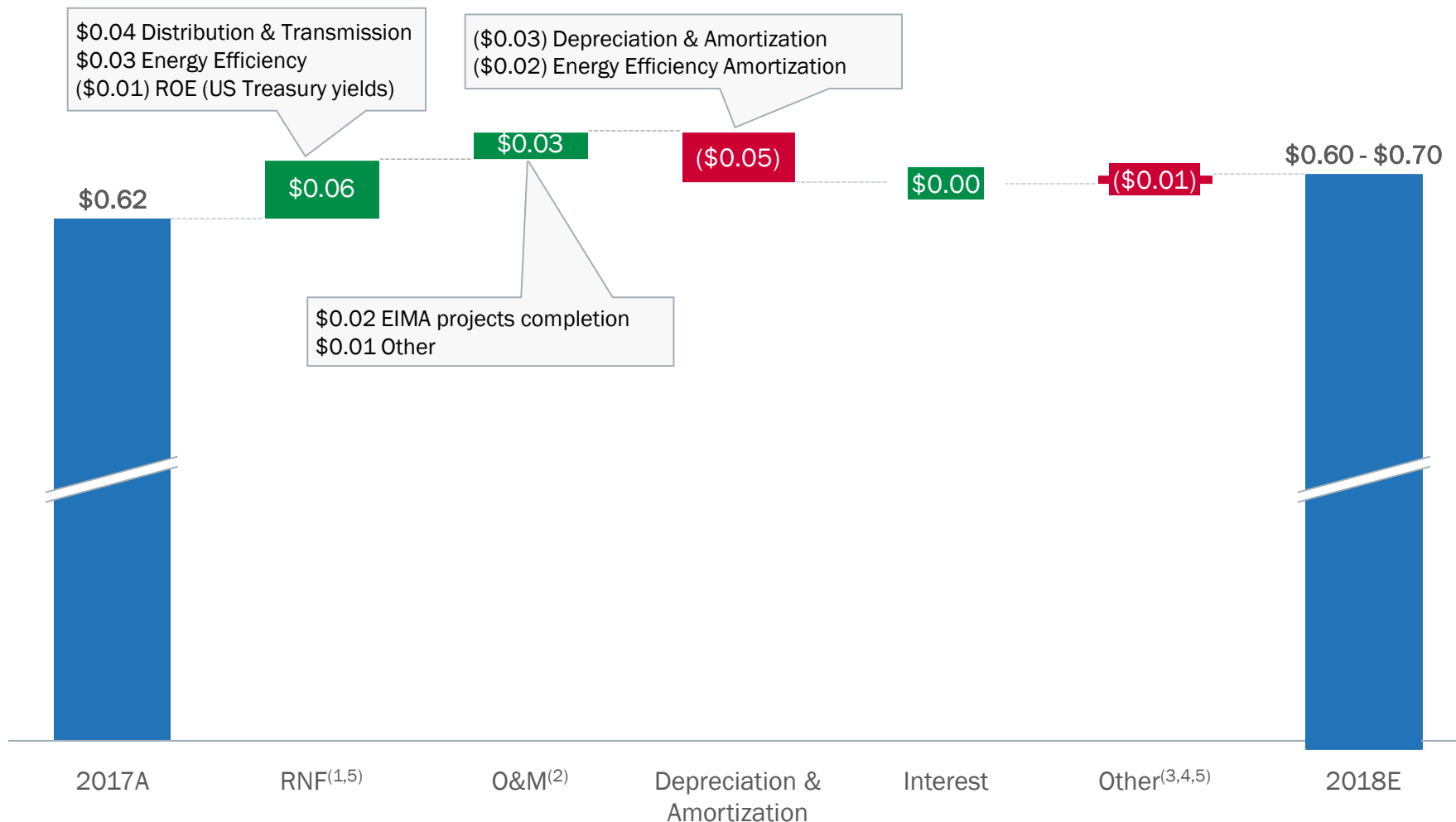
(5) Beginning in 2017 for ComEd, customer rates are adjusted to eliminate the impacts of weather and customer usage on distribution volumes.

(6) Reflects a 2016 favorable adjustment at BGE, and 2017 impairments at BGE and PHI, of certain transmission-related income tax regulatory assets

(7) PHI reflects full year of earnings in 2017 versus earnings from March 24, 2016, through December 31, 2016

2018E Earnings Waterfalls

ComEd Adjusted Operating EPS* Bridge 2017 to 2018



Note: Drivers add up to mid-point of 2018 adjusted operating EPS range

(1) Revenue net fuel (RNF) is defined as operating revenues less purchased power and fuel expense

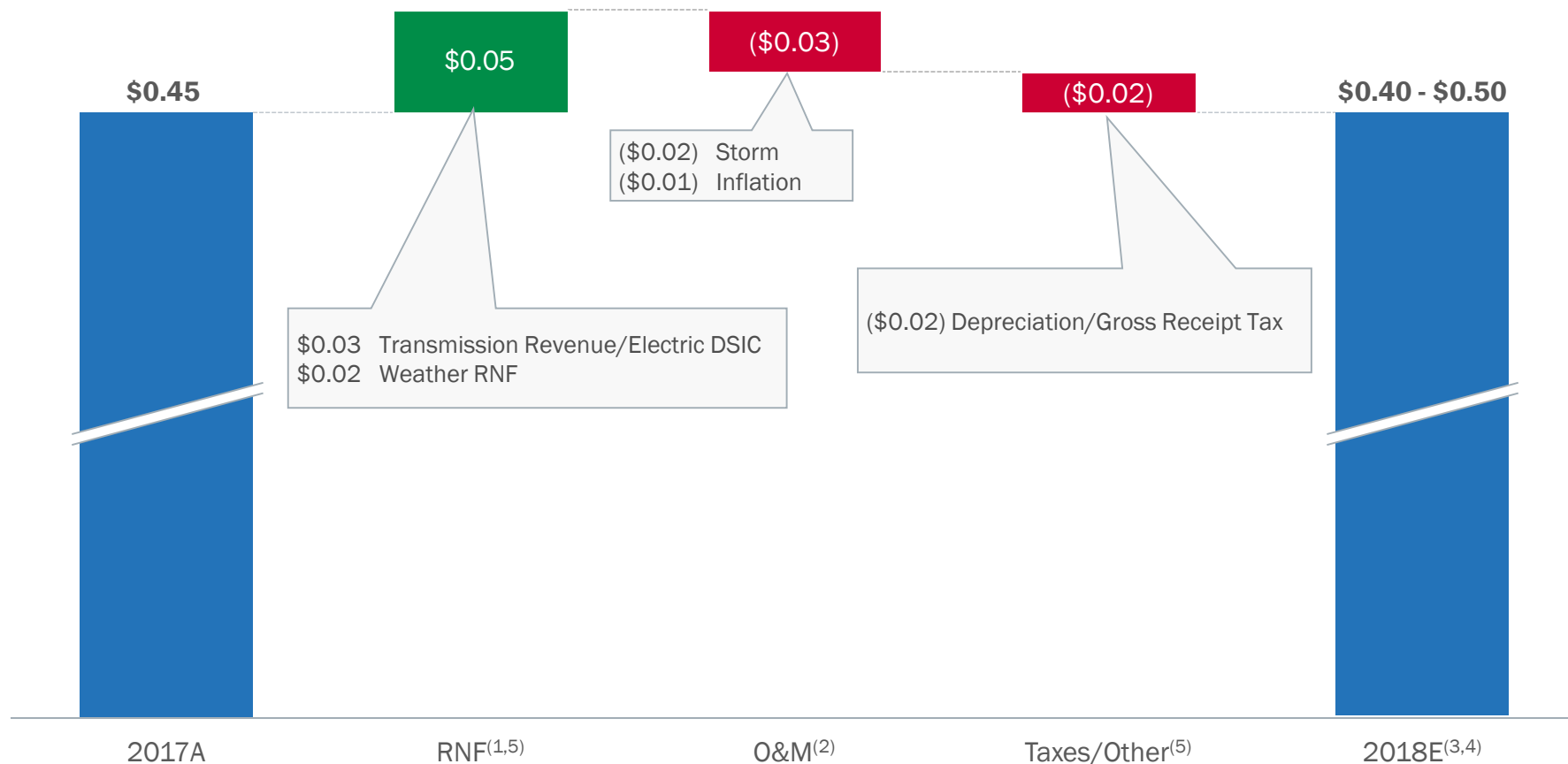
(2) O&M excludes regulatory items that are P&L neutral

(3) Shares Outstanding (diluted) are 949M in 2017 and 969M in 2018

(4) Guidance assumes an effective tax rate for 2018 of 20.7%

(5) Excludes the reductions to revenue related to tax reform that are directly offset by lower income tax expense

PECO Adjusted Operating EPS* Bridge 2017 to 2018



Note: Drivers add up to mid-point of 2018 adjusted operating EPS range

(1) Revenue net fuel (RNF) is defined as operating revenues less purchased power and fuel expense

(2) O&M excludes regulatory items that are P&L neutral

(3) Shares Outstanding (diluted) are 949M in 2017 and 969M in 2018

(4) Guidance assumes an effective tax rate for 2018 of 3.6%

(5) Excludes the reductions to revenue related to tax reform that are directly offset by lower income tax expense

BGE Adjusted Operating EPS* Bridge 2017 to 2018



Note: Drivers add up to mid-point of 2018 adjusted operating EPS range

(1) Revenue net fuel (RNF) is defined as operating revenues less purchased power and fuel expense

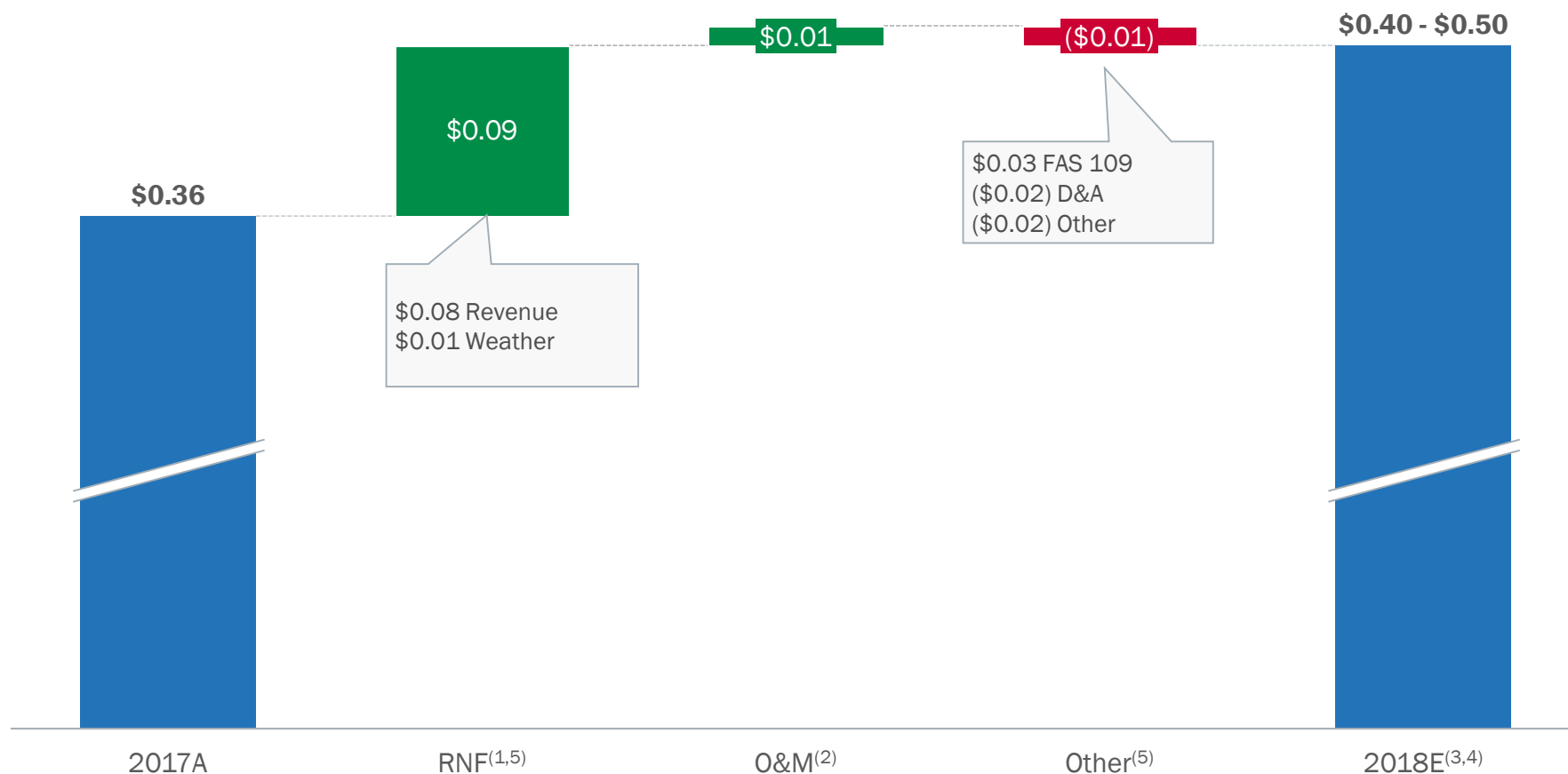
(2) O&M excludes regulatory items that are P&L neutral

(3) Shares Outstanding (diluted) are 949M in 2017 and 969M in 2018

(4) Guidance assumes an effective tax rate for 2018 of 19.8%

(5) Excludes the reductions to revenue related to tax reform that are directly offset by lower income tax expense

PHI Adjusted Operating EPS* Bridge 2017 to 2018



Note: Drivers add up to mid-point of 2018 adjusted operating EPS range

(1) Revenue net fuel (RNF) is defined as operating revenues less purchased power and fuel expense

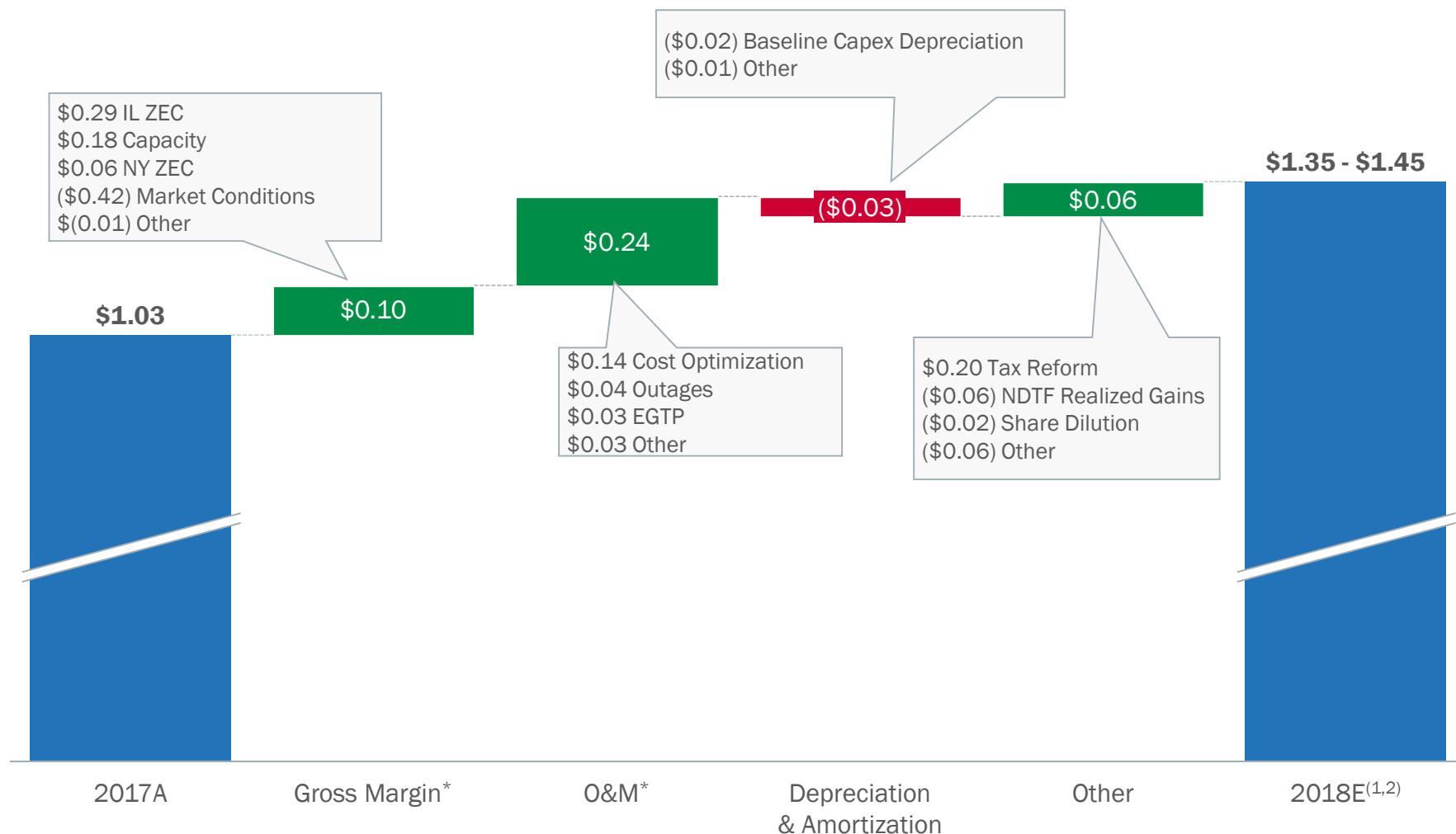
(2) O&M excludes regulatory items that are P&L neutral

(3) Shares Outstanding (diluted) are 949M in 2017 and 969M in 2018

(4) Guidance assumes an effective tax rate for 2018 of 13.2%

(5) Excludes the reductions to revenue related to tax reform that are directly offset by lower income tax expense

ExGen Adjusted Operating EPS* Bridge 2017 to 2018



Note: Drivers add up to mid-point of 2018 adjusted operating EPS range

(1) Shares Outstanding (diluted) are 949M in 2017 and 969M in 2018

(2) Guidance assumes a marginal tax rate of 25.1% for 2018

Exelon Utilities Rate Case Filing Summaries

Exelon Utilities' Distribution Rate Case Schedule

	12/17	1/18	2/18	3/18	4/18	5/18	6/18
ComEd Electric Distribution Formula Rate	Commission Order Received Dec 6				2018 Formula Rate Update Filing April		
Delmarva – MD Electric Distribution Rates	Settlement Filed Dec 18		Commission Order Expected Feb 9				
Delmarva – DE Electric Distribution Rates			Intervenor Direct Testimony Feb 21		Rebuttal Testimony Apr 6	Evidentiary Hearings May 15-17	Initial Briefs June 20 Reply Briefs June 29
Delmarva – DE Gas Distribution Rates				Intervenor Direct Testimony Mar 13		Rebuttal Testimony May 8	
Pepco Electric Distribution Rates - DC	Case Filed Dec 19						
Pepco Electric Distribution Rates - MD		Case Filed Jan 2			Intervenor Direct Testimony Apr 13	Rebuttal Testimony May 11	Evidentiary Hearings June 4-13

Note: Based on current schedules of Illinois Commerce Commission, Maryland Public Service Commission, and Delaware Public Service Commission and are subject to change

Pepco MD (Electric) Distribution Rate Case Filing

Formal Case No.	9472
Test Year	January 1, 2017 – December 31, 2017
Test Period	8 months actual and 4 months estimated
Requested Common Equity Ratio	50.28%
Requested Rate of Return	ROE: 10.10%; ROR: 7.74%
Proposed Rate Base (Adjusted)	\$1.8B
Requested Revenue Requirement Increase (Updated on February 5, 2018)	\$10.7M
Residential Total Bill % Increase	1.81%
Notes	<ul style="list-style-type: none"> • January 2, 2018, Pepco MD filed application with Maryland Public Service Commission (MDPSC) seeking increase in electric distribution base rates • On February 5, 2018, Pepco filed with the MDPSC an update to its current distribution rate case to reflect approximately \$30.7 million in annual tax savings resulting from the enactment of the TCJA • Forward looking reliability plant additions through June 2018 (\$7.8M of Revenue Requirement based on 10.10% ROE) included in revenue requirement request • Request for Rate Phase-In of \$14.9M on \$126M of plant (to cover reliability capital May 2018 to April 2019) and commitment to not file new case before January 1, 2020 <p>Procedural Schedule:</p> <ul style="list-style-type: none"> • Intervenor Direct Testimony Due: April 13, 2018 • Rebuttal Testimony Due: May 11, 2018 • Evidentiary Hearings: June 4-13, 2018 • Initial Briefs due: June 28, 2018 • Final Briefs due: July 13, 2018 • Commission Order Expected: July 31, 2018

Pepco DC (Electric) Distribution Rate Case Filing

Formal Case No.	1150
Test Year	January 1, 2017 – December 31, 2017
Test Period	8 months actual and 4 months estimated
Requested Common Equity Ratio	50.28%
Requested Rate of Return	ROE: 10.10%; ROR: 7.74%
Proposed Rate Base (Adjusted)	\$1.9B
Requested Revenue Requirement Increase	\$66.2M
Residential Total Bill % Increase	9.24%
Notes	<ul style="list-style-type: none"> • December 19, 2017, Pepco DC filed application with Public Service Commission of the District of Columbia (PSCDC) seeking increase in electric distribution base rates • Size of ask is driven by continued investments in electric distribution system to maintain and increase reliability and customer service • Forward looking reliability plant additions through December 2018 (\$7.9M of Revenue Requirement based on 10.10% ROE) included in revenue requirement request <p>Procedural Schedule:</p> <ul style="list-style-type: none"> • Commission Order Expected: December 2018

Delmarva DE (Gas) Distribution Rate Case Filing

Docket No.	17-0978
Test Year	January 1, 2017 – December 31, 2017
Test Period	6 months actual and 6 months estimated
Requested Common Equity Ratio	50.52%
Requested Rate of Return	ROE: 10.10%; ROR: 6.98%
Proposed Rate Base (Adjusted)	\$345M
Requested Revenue Requirement Increase (Updated on November 7, 2017)	\$11.0M ⁽¹⁾
Residential Total Bill % Increase	9.9%
Notes	<ul style="list-style-type: none"> • August 17, 2017, Delmarva DE filed application with Delaware Public Service Commission (DPSC) seeking increase in gas distribution base rates • Size of ask is driven by continued investments in gas distribution system to maintain and increase reliability and customer service • Forward looking reliability plant additions through August 2018 (\$1.0M of Revenue Requirement based on 10.10% ROE) included in revenue requirement request <p>Procedural Schedule</p> <ul style="list-style-type: none"> • Intervenor Direct Testimony Due: March 13, 2018 • Rebuttal Testimony Due: May 8, 2018 • Evidentiary Hearings: July 17-19, 2018 • Initial Briefs Due: August 23, 2018 • Reply Briefs Due: September 6, 2018 • Commission Order Expected: Q4 2018

(1) As permitted by Delaware law, Delmarva Power implemented interim rate increases of \$2.5 million on November 1, 2017, and will implement full allowable rates on March 17, 2018, subject to refund

Delmarva DE (Electric) Distribution Rate Case Filing

Docket No.	17-0977
Test Year	January 1, 2017 – December 31, 2017
Test Period	6 months actual and 6 months estimated
Requested Common Equity Ratio	50.52%
Requested Rate of Return	ROE: 10.10%; ROR: 6.98%
Proposed Rate Base (Adjusted)	\$805M
Requested Revenue Requirement Increase	\$31.2M ⁽¹⁾
Residential Total Bill % Increase (Updated on October 18, 2017)	4.7%
Notes	<ul style="list-style-type: none"> • August 17, 2017, Delmarva DE filed application with DPSC seeking increase in electric distribution base rates • Size of ask is driven by continued investments in electric distribution system to maintain and increase reliability and customer service • Forward looking reliability plant additions through August 2018 (\$3.1M of Revenue Requirement based on 10.10% ROE) included in revenue requirement request <p>Procedural Schedule:</p> <ul style="list-style-type: none"> • Intervenor Direct Testimony Due: February 21, 2018 • Rebuttal Testimony Due: April 6, 2018 • Evidentiary Hearings: May 15-17, 2018 • Initial Briefs Due: June 20, 2018 • Reply Briefs Due: June 29, 2018 • Commission Order Expected: Q3 2018

(1) As permitted by Delaware law, Delmarva Power implemented interim rate increases of \$2.5 million on October 16, 2017, and will implement full allowable rates on March 17, 2018, subject to refund

Delmarva MD (Electric) Distribution Rate Case Filing

Formal Case No.	9455	Per Filed Settlement
Test Year	October 1, 2016 – September 30, 2017	
Test Period	7 months actual and 5 months estimated (Updated to 12+0 on November 16, 2017)	
Requested Common Equity Ratio	50.68%	
Requested Rate of Return	ROE: 10.10%; ROR: 7.05%	ROE: 9.50% ⁽¹⁾
Proposed Rate Base (Adjusted)	\$741M	
Requested Revenue Requirement Increase (Updated on Nov. 16, 2017)	\$19.3M	\$13.4M
Residential Total Bill % Increase	1.8%	1.9%
Notes	<ul style="list-style-type: none"> July 14, 2017, Delmarva MD filed application with Maryland Public Service Commission (MDPSC) seeking increase in electric distribution base rates Forward looking reliability and other plant additions through April 2018 (\$3.1M of Revenue Requirement based on 10.10% ROE) included in revenue requirement request <p>Intervenor Positions:</p> <ul style="list-style-type: none"> Office of People's Council (OPC) revenue increase of \$5.0M or \$7.2M based on 8.65% or 9.0% ROE, respectively Staff revenue increase of \$11.1M based on 9.30% ROE <p>Procedural Schedule:</p> <ul style="list-style-type: none"> Commission Order Expected: February 9, 2018 	<ul style="list-style-type: none"> Settlement filed December 18, 2017, and evidentiary hearings held on January 5, 2018 <p>Key Settlement Provisions:</p> <ul style="list-style-type: none"> Regulatory asset/liability treatment related to costs/savings for Winter Storm Stella, AMI savings and Costs to Achieve Staff will convene a work group with DPL & OPC reps to evaluate DPL's MD reliability spend and projected reliability performance from 2017 through 2020 Prior to next filing, DPL will provide Staff and OPC education and training sessions addressing how Class Cost of Service Study (CCOSS) model functions

(1) Settlement states cost of equity solely for purposes of calculating AFUDC (Allowance for Funds Used During Construction) and regulatory asset carrying costs shall be 9.50%

ComEd Distribution Rate Case Filing

Docket #	17-0196
Filing Year	<ul style="list-style-type: none"> 2016 Calendar Year Actual Costs and 2017 Projected Net Plant Additions are used to set the rates for calendar year 2018. Rates currently in effect (docket 16-0259) for calendar year 2017 were based on 2015 actual costs and 2016 projected net plant additions.
Reconciliation Year	<ul style="list-style-type: none"> Reconciles Revenue Requirement reflected in rates during 2016 to 2016 Actual Costs Incurred. Revenue requirement for 2016 is based on docket 15-0287 (2014 actual costs and 2015 projected net plant additions) approved in December 2015.
Requested Common Equity Ratio	45.89%
Requested Rate of Return	~ROE: 8.40%; ROR: ~6.50%
Proposed Rate Base (Adjusted)	~\$9.7B
Requested Revenue Requirement Increase	\$95.6M
Residential Total Bill % Increase	0.8%
Notes	<ul style="list-style-type: none"> April 13, 2017, ComEd filed application with Illinois Commerce Commission seeking increase in electric distribution base rates Size of ask is driven by continued investments in electric distribution system to maintain and increase reliability and customer service \$9,662 million – Filing year (represents projected year-end rate base using 2016 actual plus 2017 projected capital additions). 2017 and 2018 earnings will reflect 2017 and 2018 year-end rate base respectively. \$8,807 million - Reconciliation year (represents year-end rate base for 2016) \$95.6M increase (\$17.5M increase due to the 2016 reconciliation and collar adjustment in addition to a \$78.1M increase related to the filing year). The 2016 reconciliation impact on net income was recorded in 2016 as a regulatory asset. <p>Procedural Schedule:</p> <ul style="list-style-type: none"> Commission Order Received: December 06, 2017 Rates are effective January 1, 2018

Appendix

Reconciliation of Non-GAAP Measures

Q4 QTD GAAP EPS Reconciliation

Three Months Ended December 31, 2016	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
2016 GAAP (Loss) Earnings Per Share	\$(0.04)	\$0.09	\$0.10	\$0.11	\$0.03	\$(0.06)	\$0.22
Mark-to-market impact of economic hedging activities	(0.05)	-	-	-	-	-	(0.05)
Unrealized losses related to NDT fund investments	0.01	-	-	-	-	-	0.01
Amortization of commodity contract intangibles	0.03	-	-	-	-	-	0.03
Merger and integration costs	0.02	-	-	-	-	-	0.02
Reassessment of state deferred income taxes	0.02	-	-	-	-	-	0.01
Asset retirement obligation	(0.08)	-	-	-	-	-	(0.08)
Merger commitments	0.04	-	-	-	0.01	(0.01)	0.04
Plant retirements and divestitures	0.10	-	-	-	-	-	0.10
Cost management program	0.01	-	-	-	-	-	0.01
Curtailment of Generation growth and development activities	0.06	-	-	-	-	-	0.06
Noncontrolling interests	0.07	-	-	-	-	-	0.07
2016 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$0.18	\$0.09	\$0.10	\$0.11	\$0.05	\$(0.08)	\$0.44

NOTE: All amounts shown are per Exelon share and represent contributions to Exelon's EPS. Amounts may not add due to rounding.

Q4 QTD GAAP EPS Reconciliation (continued)

<u>Three Months Ended December 31, 2017</u>	<u>ExGen</u>	<u>ComEd</u>	<u>PECO</u>	<u>BGE</u>	<u>PHI</u>	<u>Other</u>	<u>Exelon</u>
2017 GAAP (Loss) Earnings Per Share	\$2.29	\$0.12	\$0.11	\$0.08	\$0.00	(\$0.66)	\$1.94
Mark-to-market impact of economic hedging activities	0.01	-	-	-	-	-	0.01
Unrealized gains related to NDT fund investments	(0.12)	-	-	-	-	-	(0.12)
Amortization of commodity contract intangibles	0.01	-	-	-	-	-	0.01
Merger and integration costs	-	-	-	-	-	-	-
Long-lived asset impairments	0.01	-	-	-	0.02	-	0.03
Plant retirements and divestitures	0.07	-	-	-	-	-	0.07
Cost management program	0.01	-	-	-	-	-	0.01
Reassessment of state deferred income taxes	(1.94)	-	(0.01)	0.01	0.03	0.61	(1.30)
Asset retirement obligation	-	-	-	-	-	-	-
Gain on deconsolidation of business	(0.14)	-	-	-	-	-	(0.14)
Vacation policy change	(0.03)	-	-	-	(0.01)	-	(0.03)
Change in environmental remediation liabilities	0.03	-	-	-	-	-	0.03
Noncontrolling interests	0.04	-	-	-	-	-	0.04
2017 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$0.26	\$0.13	\$0.10	\$0.08	\$0.05	(\$0.07)	\$0.55

NOTE: All amounts shown are per Exelon share and represent contributions to Exelon's EPS. Amounts may not add due to rounding.

Q4 YTD GAAP EPS Reconciliation

<u>Twelve Months Ended December 31, 2016</u>	<u>ExGen</u>	<u>ComEd</u>	<u>PECO</u>	<u>BGE</u>	<u>PHI</u>	<u>Other</u>	<u>Exelon</u>
2016 GAAP Earnings (Loss) Per Share	\$0.54	\$0.41	\$0.47	\$0.31	(\$0.07)	(\$0.44)	\$1.22
Mark-to-market impact of economic hedging activities	0.03	-	-	-	-	-	0.03
Unrealized gains related to NDT fund investments	(0.13)	-	-	-	-	-	(0.13)
Amortization of commodity contract intangibles	0.04	-	-	-	-	-	0.04
Merger and integration costs	0.04	-	-	-	0.05	0.04	0.12
Long-lived asset impairments	0.11	-	-	-	-	-	0.11
Asset retirement obligation	(0.08)	-	-	-	-	-	(0.08)
Reassessment of state deferred income taxes	0.02	-	-	-	-	(0.01)	0.01
Merger commitments	0.05	-	-	-	0.27	0.16	0.47
Plant retirements and divestitures	0.47	-	-	-	-	-	0.47
Cost management program	0.03	-	-	-	-	-	0.04
Like-kind exchange tax position	-	0.16	-	-	-	0.05	0.21
Curtailment of Generation growth and development activities	0.06	-	-	-	-	-	0.06
Noncontrolling interests	0.11	-	-	-	-	-	0.11
2016 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$1.27	\$0.57	\$0.48	\$0.31	\$0.25	(\$0.20)	\$2.68

NOTE: All amounts shown are per Exelon share and represent contributions to Exelon's EPS. Amounts may not add due to rounding.

Q4 YTD GAAP EPS Reconciliation (continued)

<u>Twelve Months Ended December 31, 2017</u>	<u>ExGen</u>	<u>ComEd</u>	<u>PECO</u>	<u>BGE</u>	<u>PHI</u>	<u>Other</u>	<u>Exelon</u>
2017 GAAP Earnings (Loss) Per Share	\$2.84	\$0.60	\$0.46	\$0.32	\$0.38	(\$0.63)	\$3.97
Mark-to-market impact of economic hedging activities	0.11	-	-	-	-	-	0.11
Unrealized gains related to NDT fund investments	(0.34)	-	-	-	-	-	(0.34)
Amortization of commodity contract intangibles	0.04	-	-	-	-	-	0.04
Merger and integration costs	0.05	-	-	-	(0.01)	-	0.04
Merger commitments	(0.02)	-	-	-	(0.06)	(0.06)	(0.14)
Long-lived asset impairments	0.32	-	-	-	0.02	-	0.34
Plant retirements and divestitures	0.22	-	-	-	-	-	0.22
Reassessment of state deferred income taxes	(1.96)	-	(0.01)	0.01	0.04	0.56	(1.37)
Cost management program	0.03	-	-	0.01	-	-	0.04
Like-kind exchange tax position	-	0.02	-	-	-	(0.05)	(0.03)
Tax settlements	(0.01)	-	-	-	-	-	(0.01)
Bargain purchase gain	(0.25)	-	-	-	-	-	(0.25)
Gain on deconsolidation of business	(0.14)	-	-	-	-	-	(0.14)
Vacation policy change	(0.03)	-	-	-	(0.01)	-	(0.03)
Change in Environmental Remediation Liabilities	0.03	-	-	-	-	-	0.03
Noncontrolling interests	0.12	-	-	-	-	-	0.12
2017 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$1.03	\$0.62	\$0.45	\$0.33	\$0.36	(\$0.19)	\$2.60

NOTE: All amounts shown are per Exelon share and represent contributions to Exelon's EPS. Amounts may not add due to rounding.

Projected GAAP to Operating Adjustments

- **Exelon's projected 2018 adjusted (non-GAAP) operating earnings excludes the earnings effects of the following:**
 - Mark-to-market adjustments from economic hedging activities
 - Unrealized gains and losses from NDT fund investments to the extent not offset by contractual accounting as described in the notes to the consolidated financial statements
 - Non-cash amortization of intangible assets, net, related to commodity contracts recorded at fair value at the ConEdison Solutions and FitzPatrick acquisition dates
 - Certain merger and integration costs associated with the PHI and FitzPatrick acquisitions
 - Certain costs related to plant retirements
 - Costs incurred related to a cost management program
 - Generation's noncontrolling interest, primarily related to CENG exclusion items
 - Other unusual items

GAAP to Non-GAAP Reconciliations

YE 2018 Exelon FFO Calculation (\$M) ^(1,2)		YE 2018 Exelon Adjusted Debt Calculation (\$M) ^(1,2)	
GAAP Operating Income	\$3,450	Long-Term Debt (including current maturities)	\$33,075
Depreciation & Amortization	\$3,850	Short-Term Debt	\$1,125
EBITDA	\$7,300	+ PPA and Operating Lease Imputed Debt ⁽⁵⁾	\$1,025
+/- Non-operating activities and nonrecurring items ⁽³⁾	\$350	+ Pension/OPEB Imputed Debt ⁽⁶⁾	\$4,000
- Interest Expense	(\$1,400)	- Off-Credit Treatment of Debt ⁽⁷⁾	(\$1,875)
+ Current Income Tax (Expense)/Benefit	\$100	- Surplus Cash Adjustment ⁽⁸⁾	(\$1,075)
+ Nuclear Fuel Amortization	\$1,075	+/- Other S&P Adjustments ⁽⁴⁾	(\$250)
+/- Other S&P Adjustments ⁽⁴⁾	\$275	= Adjusted Debt (b)	\$36,025
= FFO (a)	\$7,700		

YE 2018 Exelon FFO/Debt ^(1,2)		
FFO (a)	=	21%
Adjusted Debt (b)		

- (1) All amounts rounded to the nearest \$25M and may not add due to rounding
(2) Calculated using S&P Methodology. Due to ring-fencing, S&P deconsolidates BGE from Exelon and analyzes solely as an equity investment.
(3) Reflects impact of operating adjustments on GAAP EBITDA
(4) Reflects other adjustments as prescribed by S&P
(5) Reflects present value of net capacity purchases and present value of minimum future operating lease payments
(6) Reflects after-tax underfunded pension/OPEB
(7) Reflects non-recourse project debt
(8) Reflects 75% of excess cash applied against balance of LTD

GAAP to Non-GAAP Reconciliations

YE 2018 ExGen FFO Calculation (\$M) ^(1,2)		YE 2018 ExGen Adjusted Debt Calculation (\$M) ^(1,2)	
GAAP Operating Income	\$1,025	Long-Term Debt (including current maturities)	\$8,850
Depreciation & Amortization	<u>\$1,800</u>	Short-Term Debt	\$0
EBITDA	\$2,825	+ PPA and Operating Lease Imputed Debt ⁽⁵⁾	\$700
+/- Non-operating activities and nonrecurring items ⁽³⁾	\$350	+ Pension/OPEB Imputed Debt ⁽⁶⁾	\$1,700
- Interest Expense	(\$400)	- Off-Credit Treatment of Debt ⁽⁷⁾	(\$1,875)
+ Current Income Tax (Expense)/Benefit	(\$225)	- Surplus Cash Adjustment ⁽⁸⁾	(\$700)
+ Nuclear Fuel Amortization	\$1,075	+/- Other S&P Adjustments ⁽⁴⁾	<u>\$275</u>
+/- Other S&P Adjustments ⁽⁴⁾	<u>\$75</u>	= Adjusted Debt (b)	\$8,950
= FFO (a)	\$3,700		

YE 2018 ExGen FFO/Debt ^(1,2)	
FFO (a)	
Adjusted Debt (b)	
	= 41%

(1) All amounts rounded to the nearest \$25M and may not add due to rounding

(2) Calculated using S&P Methodology

(3) Reflects impact of operating adjustments on GAAP EBITDA

(4) Reflects other adjustments as prescribed by S&P

(5) Reflects present value of net capacity purchases and present value of minimum future operating lease payments

(6) Reflects after-tax underfunded pension/OPEB

(7) Reflects non-recourse project debt

(8) Reflects 75% of excess cash applied against balance of LTD

GAAP to Non-GAAP Reconciliations

YE 2018 ExGen Net Debt Calculation (\$M)^(1,2)

Long-Term Debt (including current maturities)	\$8,850
Short-Term Debt	\$0
- Surplus Cash Adjustment	<u>(\$950)</u>
= Net Debt (a)	\$7,900

YE 2018 ExGen Operating EBITDA Calculation (\$M)⁽¹⁾

GAAP Operating Income ⁽³⁾	\$950
Depreciation & Amortization ⁽³⁾	<u>\$1,700</u>
EBITDA ⁽³⁾	\$2,650
+/- Non-operating activities and nonrecurring items ⁽²⁾	\$525
= Operating EBITDA (b)	\$3,175

YE 2018 Book Debt / EBITDA

Net Debt (a)		
	=	2.5x
Operating EBITDA (b)		

YE 2018 ExGen Net Debt Calculation (\$M)^(1,2)

Long-Term Debt (including current maturities)	\$8,850
Short-Term Debt	\$0
- Surplus Cash Adjustment	<u>(\$950)</u>
- Nonrecourse Debt	<u>(\$2,075)</u>
= Net Debt (a)	\$5,825

YE 2018 ExGen Operating EBITDA Calculation (\$M)⁽¹⁾

GAAP Operating Income ⁽³⁾	\$950
Depreciation & Amortization ⁽³⁾	<u>\$1,700</u>
EBITDA ⁽³⁾	\$2,650
+/- Non-operating activities and nonrecurring items ⁽²⁾	\$525
- EBITDA from projects financed by nonrecourse debt	<u>(\$275)</u>
= Operating EBITDA (b)	\$2,900

YE 2018 Recourse Debt / EBITDA

Net Debt (a)		
	=	2.0x
Operating EBITDA (b)		

(1) All amounts rounded to the nearest \$25M

(2) Reflects impact of operating adjustments on GAAP EBITDA

(3) Includes Exelon-operated nuclear plants, at ownership

GAAP to Non-GAAP Reconciliations

Q4 2017 Operating ROE Reconciliation (\$M) ⁽¹⁾	ACE	Delmarva	Pepco	Legacy EXC	Consolidated EU
Net Income (GAAP) ⁽¹⁾	\$77	\$121	\$205	\$1,308	\$1,711
Operating Exclusions	(\$20)	(\$13)	(\$20)	\$28	(\$24)
Adjusted Operating Earnings ⁽¹⁾	\$58	\$108	\$185	\$1,336	\$1,687
Average Equity	\$1,038	\$1,330	\$2,417	\$13,003	\$17,787
Operating ROE (Adjusted Operating Earnings/Average Equity)	5.6%	8.1%	7.7%	10.3%	9.5%

Q4 2016 Operating ROE Reconciliation ⁽¹⁾	ACE	Delmarva	Pepco	Legacy EXC	Consolidated EU
Net Income (GAAP) ⁽¹⁾	(\$42)	(\$9)	\$42	\$1,102	\$1,103
Operating exclusions	\$99	\$89	\$127	\$146	\$461
Adjusted Operating Earnings ⁽¹⁾	\$57	\$80	\$170	\$1,258	\$1,564
Average Equity	\$1,017	\$1,282	\$2,270	\$11,951	\$16,523
Operating ROE (Adjusted Operating Earnings/Average Equity)	5.6%	6.3%	7.5%	10.5%	9.5%

Note: Amounts may not sum due to rounding

(1) ACE, Delmarva, and Pepco represents full year of earnings

GAAP to Non-GAAP Reconciliations

2018 Adjusted Cash from Ops Calculation (\$M) ⁽¹⁾	ComEd	PECO	BGE	PHI	ExGen	Other	Exelon
Net cash flows provided by operating activities (GAAP)	\$1,625	\$600	\$625	\$1,125	\$4,125	\$275	\$8,375
Other cash from investing activities	-	-	-	-	(\$275)	-	(\$275)
Intercompany receivable adjustment	-	-	-	-	-	-	-
Counterparty collateral activity	-	-	-	-	-	-	-
Adjusted Cash Flow from Operations	\$1,625	\$600	\$625	\$1,125	\$3,875	\$275	\$8,100

2018 Cash From Financing Calculation (\$M) ⁽¹⁾	ComEd	PECO	BGE	PHI	ExGen	Other	Exelon
Net cash flow provided by financing activities (GAAP)	\$750	(\$25)	\$400	\$350	(\$950)	(\$225)	\$300
Dividends paid on common stock	\$450	\$300	\$200	\$300	\$750	(\$675)	\$1,325
Intercompany receivable adjustment	-	-	-	-	-	-	-
Financing Cash Flow	\$1,200	\$275	\$600	\$650	(\$200)	(\$900)	\$1,625

Exelon Total Cash Flow Reconciliation ⁽¹⁾	2018
GAAP Beginning Cash Balance	\$900
Adjustment for Cash Collateral Posted	<u>\$500</u>
Adjusted Beginning Cash Balance ⁽³⁾	\$1,400
Net Change in Cash (GAAP) ⁽²⁾	<u>\$575</u>
Adjusted Ending Cash Balance ⁽³⁾	\$1,975
Adjustment for Cash Collateral Posted	<u>(\$525)</u>
GAAP Ending Cash Balance	\$1,475

(1) All amounts rounded to the nearest \$25M. Items may not sum due to rounding.

(2) Represents the GAAP measure of net change in cash, which is the sum of cash flow from operations, cash from investing activities, and cash from financing activities. Figures reflect cash capital expenditures and CENG fleet at 100%.

(3) Adjusted Beginning and Ending cash balances reflect GAAP Beginning and End Cash Balances excluding counterparty collateral activity

GAAP to Non-GAAP Reconciliations

ExGen Adjusted O&M Reconciliation (\$M) ⁽¹⁾	2018	2019	2020	2021
GAAP O&M	\$5,225	\$5,000	\$4,925	\$4,950
Decommissioning ⁽²⁾	-	-	-	-
TMI Retirement	-	-	-	-
Oyster Creek Retirement	(25)	-	-	-
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses ⁽³⁾	(250)	(300)	(250)	(250)
O&M for managed plants that are partially owned	(400)	(400)	(425)	(425)
Other	-	-	25	25
Adjusted O&M (Non-GAAP)	\$4,550	\$4,300	\$4,275	\$4,300

2018-2021 ExGen Available Cash Flow and Uses of Cash Calculation (\$M) ⁽¹⁾	
Cash from Operations (GAAP)	\$15,975
Other Cash from Investing and Financing Activities	(\$1,200)
Baseline Capital Expenditures ⁽⁴⁾	(\$3,675)
Nuclear Fuel Capital Expenditures	(\$3,450)
Free Cash Flow before Growth CapEx and Dividend	\$7,625

(1) All amounts rounded to the nearest \$25M. Items may not sum due to rounding.

(2) Reflects earnings neutral O&M

(3) Reflects the direct cost of sales of certain businesses, which are included in Total Gross Margin*

(4) Baseline capital expenditures refer to maintenance and required capital expenditures necessary for day-to-day plant operations and includes merger commitments