

# Earnings Conference Call Third Quarter 2017

November 2, 2017



# Cautionary Statements Regarding Forward-Looking Information

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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 (to be filed on November 2, 2017) 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

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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 34 of this presentation.

# Strong Third Quarter Results

## Q3 2017 EPS Results



- GAAP earnings were \$0.85/share in Q3 2017 vs. \$0.53/share in Q3 2016
- Adjusted operating earnings\* were \$0.85/share in Q3 2017 vs. \$0.91/share in Q3 2016, at the mid-point of our guidance range of \$0.80-\$0.90/share

Note: Amounts may not sum due to rounding

\* Refer to pages 3 and 4 for information regarding non-GAAP financial measures

# Operating Highlights

Exelon Utilities Operational Metrics					
Operations	Metric	Q3 2017			
		BGE	ComEd	PECO	PHI
Electric Operations	OSHA Recordable Rate				
	2.5 Beta SAIFI (Outage Frequency) <sup>(1)</sup>				
	2.5 Beta CAIDI (Outage Duration)				
Customer Operations	Customer Satisfaction				
	Service Level % of Calls Answered in <30 sec				
	Abandon Rate				
Gas Operations	Percent of Calls Responded to in <1 Hour		No Gas Operations		

- BGE and ComEd are meeting 1<sup>st</sup> decile performance in CAIDI
- BGE, ComEd and PECO are on track for 1<sup>st</sup> decile performance in SAIFI
- ComEd and PHI are meeting 1<sup>st</sup> decile performance in Service Level

(1) 2.5 Beta SAIFI is YE projection

(2) Excludes Salem

Q1	Q2
Q3	Q4

## Exelon Generation Operational Metrics

- Continued best in class performance across our Nuclear fleet:
  - Q3 Nuclear Capacity Factor: 96.1%<sup>(2)</sup>
  - Owned and operated Q3 production of 41 TWh was best on record
- Strong performance across our Fossil and Renewable fleet:
  - Q3 Renewables energy capture: 95.9%
  - Q3 Power dispatch match: 98.4%

# Resiliency and Energy Market Reform

## Price Formation

- PJM has stated that it is prepared to implement its reforms allowing all resources to set LMP by mid-2018
- “FERC should expedite its efforts with states, RTO/ISOs, and other stakeholders to improve energy price formation in centrally-organized wholesale electricity markets.” – DOE Staff Report, August 2017
- The Commission should focus “first and foremost on the optimization of price formation in the energy and ancillary service markets.” III. Commerce Comm’n Comments at 7
- “PJM staff is proposing to reform the existing pricing model in order to ensure that the cost of serving load is reflected in LMP to the fullest extent possible... This follows the principles of sound market design.” - William W. Hogan, October 23, 2017

## Resiliency

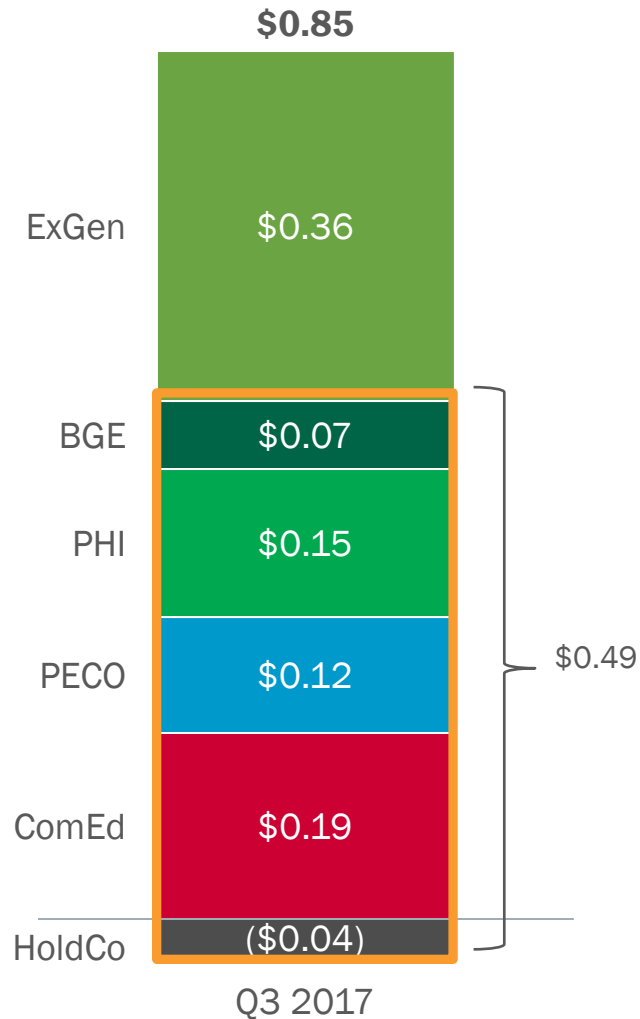
- “Accurately valuing resilience is not a zero-sum game. Compensating base-load generation does not equate to destruction of markets. On the contrary, I think it’s a step toward accurately pricing contributions of all market participants.” – FERC Chairman Neil Chatterjee, October 13, 2017
- “The unknowns are what we're going to have to deal with: if there was a physical attack, if you had [an explosion like the one on the Spectra pipeline that wasn't] fixed in a timely manner heading into the winter heating season, central Pennsylvania would have had potential issues. . . So now the conversation's gotten broader around these cascading events, and then how do you price resiliency? That conversation needs to take place.” FERC Commissioner Rob Powelson, October 27, 2017
- “We used to talk about equipment failure and outages caused by storms. Now, the threat profile has changed, the considerations are broader. There could be intentional attacks – cyber or physical. Those concerns lead us beyond reliability and into resilience.” PJM CEO and President Andrew L. Ott, September 20, 2017

## Exelon recommends that FERC:

1. Immediately require PJM to submit its energy price formation proposal
2. Require the affected RTOs to submit detailed information on the grid’s vulnerabilities to enable the development of a design basis threat analysis that can inform cost-effective market reforms, and
3. State that it will not interfere with state programs that value resilient resources like nuclear plants

# Third Quarter Adjusted Operating Earnings\* Drivers

## Q3 2017 Adjusted Operating EPS\* Results



## Q3 2017 vs. Guidance of \$0.80 - \$0.90

### Exelon Utilities

- ↑ Reduced storm activity
- ↑ Lower O&M

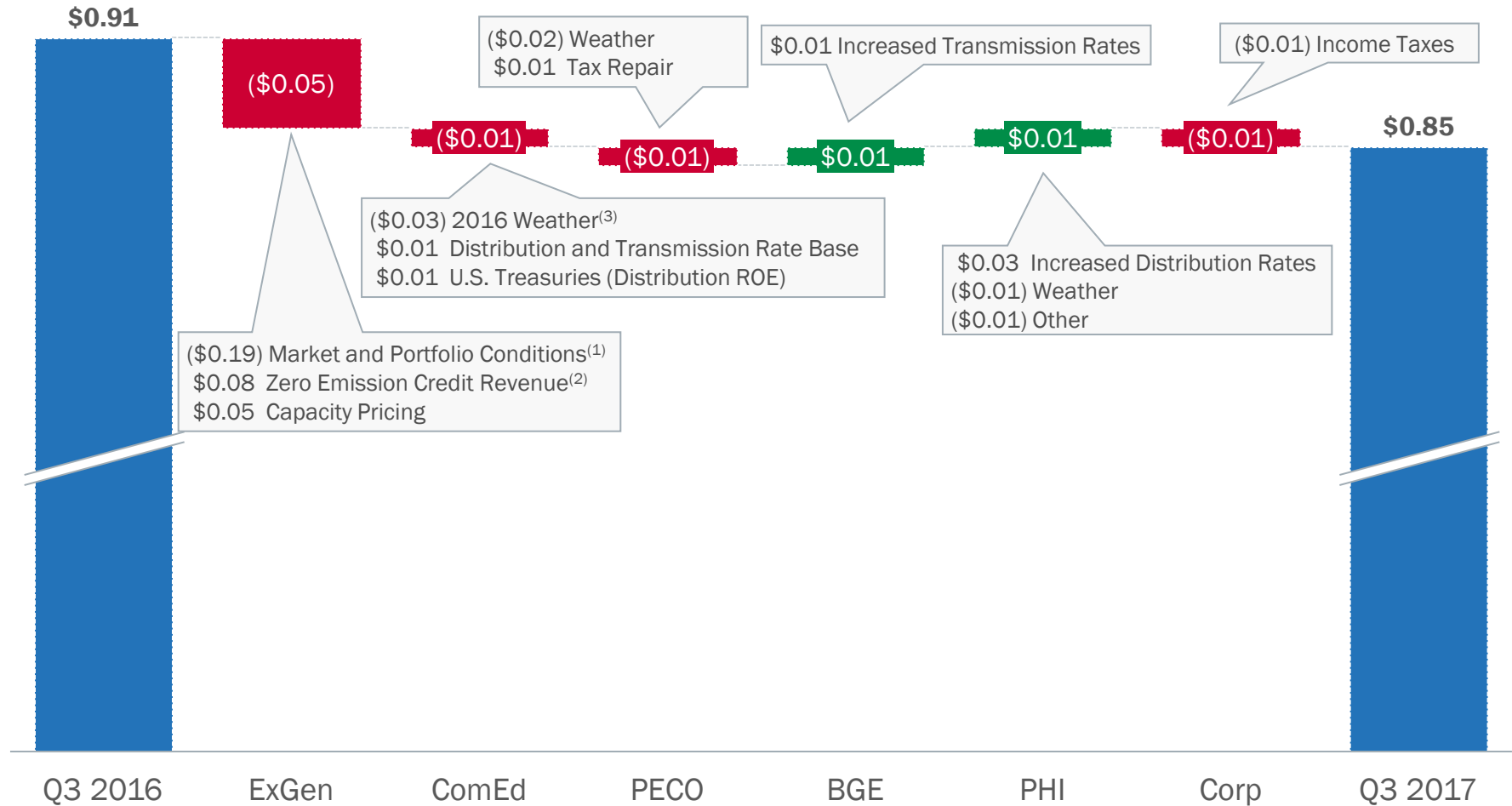
### Exelon Generation

- ↓ Constellation Gross Margin
- ↑ Timing of O&M

Note: Amounts may not sum due to rounding



# QTD Adjusted Operating Earnings\* Waterfall



Note: Amounts may not sum due to rounding

(1) Includes the unfavorable impacts of lower load volumes delivered due to mild weather and lower realized energy prices related to Exelon's ratable hedging strategy

(2) Reflects the impact of the New York Clean Energy Standard

(3) Pursuant to the Illinois Future Energy Jobs Act, beginning in 2017, customer rates for ComEd are adjusted to eliminate the favorable and unfavorable impacts of weather and customer usage patterns on distribution volumes

# Narrowing 2017 Adjusted Operating Earnings\* Guidance Range



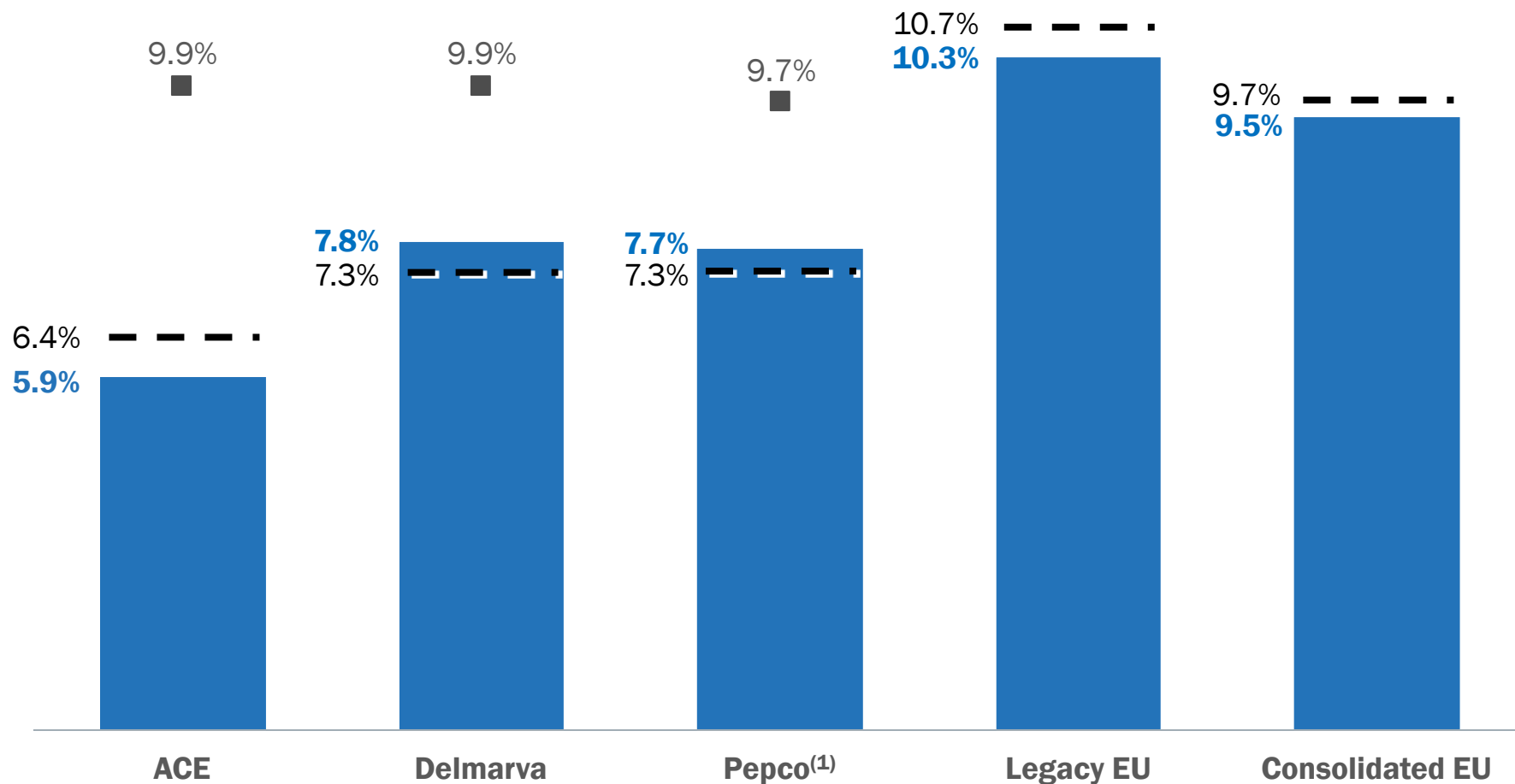
(1) 2017 earnings guidance based on expected average outstanding shares of 949M. Earnings guidance for OpCos may not sum up to consolidated EPS guidance.

(2) Revised guidance reflects delay in Illinois ZEC revenue recognition for 2017 until 2018, shifting \$0.09 of EPS

# Trailing 12 Month ROE vs Allowed ROE

## Twelve Month Trailing Earned ROEs\*

■ Allowed ROE    — Q2 2017 TTM Earned ROE    ■ Q3 2017 TTM Earned ROE



Note: Represents the period from 10/1/2016 to 9/30/2017. ROEs represent weighted average across all lines of business (Electric Distribution, Gas Distribution, and Transmission).

(1) Pepco MD Distribution allowed ROE is based on authorized ROE of 9.55% for the rates that were in effect during the trailing twelve month period. The order issued on 10/20/17 authorized an ROE of 9.50%.

# Exelon Utilities' Distribution Rate Case Updates

## Pepco DC Order

Authorized Revenue Requirement Increase <sup>(1)</sup>	\$36.9M
Authorized ROE	9.50%
Common Equity Ratio	49.14%
Order Received	7/25/17

## ACE NJ Order

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

## Pepco MD Order

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

## ComEd Filing

Requested Revenue Requirement Increase <sup>(1)</sup>	\$95.6M <sup>(2)</sup>
Requested ROE	8.40%
Requested Common Equity Ratio	45.89%
Order Expected	Q4 2017

## Delmarva MD Filing

Requested Revenue Requirement Increase <sup>(1)</sup>	\$21.6M <sup>(4)</sup>
Requested ROE	10.10%
Requested Common Equity Ratio	50.68%
Order Expected	2/14/18

## Delmarva DE Electric Filing

Requested Revenue Requirement Increase <sup>(1,3)</sup>	\$31.2M
Requested ROE	10.10%
Requested Common Equity Ratio	50.52%
Order Expected	Q3 2018

## Delmarva DE Gas Filing

Requested Revenue Requirement Increase <sup>(1,3)</sup>	\$12.9M
Requested ROE	10.10%
Requested Common Equity Ratio	50.52%
Order Expected	Q3 2018

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

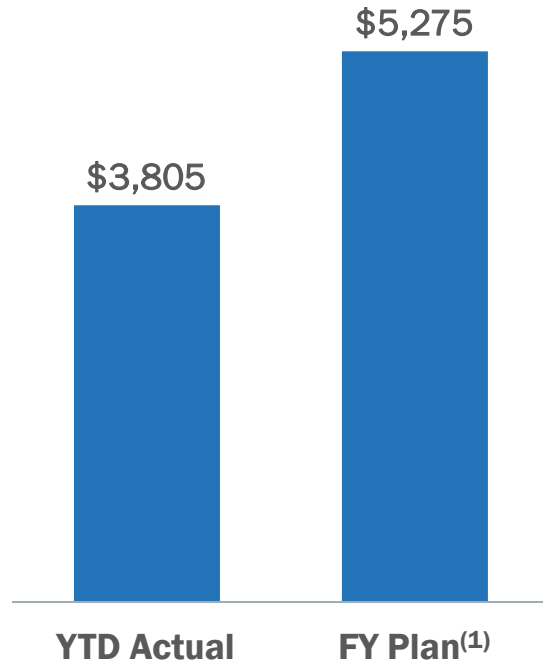
(2) Amount represents ComEd's position filed in Rebuttal testimony on July 21, 2017

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

(4) Amount represents adjusted requested revenue requirement filed on September 28, 2017

# Utility CapEx Update

## 2017 Exelon Utilities CapEx Spend (\$M)



## Notable Projects

### • Pepco's Waterfront Substation

- \$182 million invested to date. Expected completion by end of 2017
- Part of "Capital Grid" project
- Replaces aging infrastructure and improves substation performance
- Will support existing customers and planned development in the Capitol Riverfront and Southwest Waterfront areas

### • ComEd's Grand Prairie Gateway transmission line

- \$203 million investment
- 60-mile, 345kV line through four northern Illinois counties
- Energized April 2017
- Estimated customer savings of \$121 to \$325 million, net of construct costs, within the first 15 years
- Reduces carbon emissions by nearly 500,000 tons within the first 15 years



**Exelon Utilities on track to meet their 2017 capital investment commitments to the benefit of customers**

(1) FY Plan rounded to the nearest \$25M

# Exelon Generation: Gross Margin Update

	September 30, 2017			Change from June 30, 2017		
Gross Margin Category (\$M) <sup>(1)</sup>	2017	2018	2019	2017	2018	2019
Open Gross Margin <sup>(2,5)</sup> (including South, West, Canada hedged gross margin)	\$3,600	\$3,900	\$3,700	\$(150)	\$(100)	\$(100)
Capacity and ZEC Revenues <sup>(2,5,6)</sup>	\$1,700	\$2,300	\$2,000	\$(150)	\$100	\$(50)
Mark-to-Market of Hedges <sup>(2,3)</sup>	\$2,150	\$650	\$450	\$250	\$100	\$50
Power New Business / To Go	\$100	\$700	\$850	\$(100)	\$(150)	\$(100)
Non-Power Margins Executed	\$350	\$200	\$100	\$50	\$50	-
Non-Power New Business / To Go	\$100	\$300	\$400	\$(50)	\$(50)	-
<b>Total Gross Margin*<sup>(4,5)</sup></b>	<b>\$8,000</b>	<b>\$8,050</b>	<b>\$7,500</b>	<b>\$(150)</b>	<b>\$(50)</b>	<b>\$(200)</b>

## Recent Developments

- Delay in recognition of Illinois ZEC revenues lowers the Capacity and ZEC Revenues line in 2017 by \$150M and increases the 2018 line by \$150M – see slide 21 for details
- Excluding impact of Illinois ZEC timing:
  - In 2017, \$50M reduction in Power New Business targets
  - In both 2018 and 2019, \$100M reduction due to lower power and capacity prices and \$100M reduction to Power New Business Targets
- Behind ratable hedging position reflects the upside we see in power prices
  - ~11-14% 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

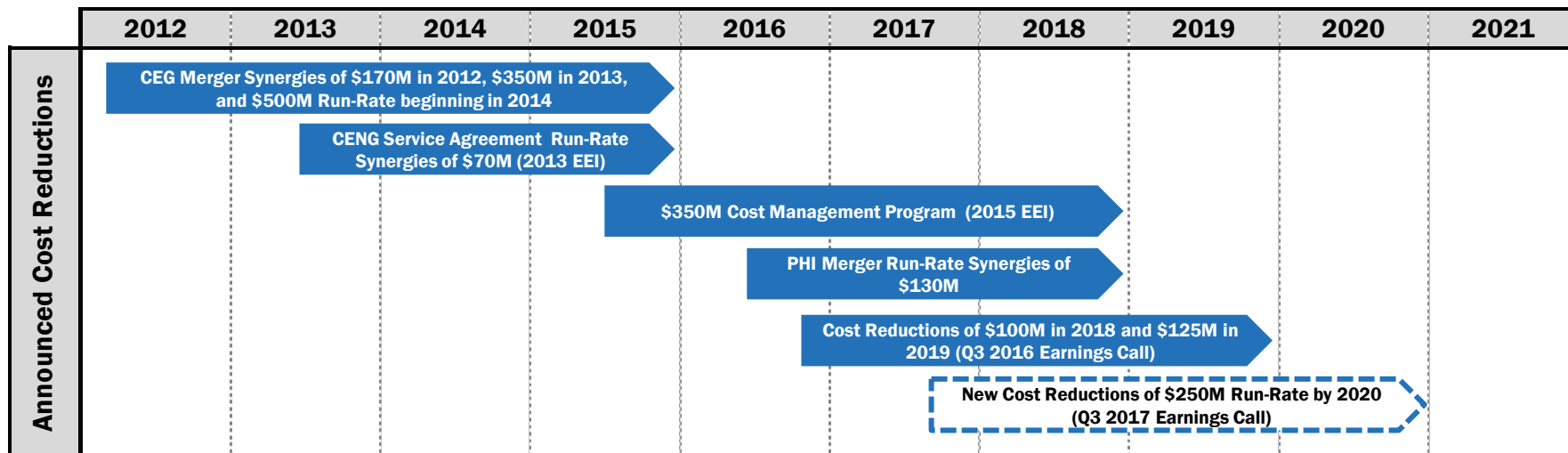
(4) Based on September 30, 2017, market conditions

(5) Reflects TMI and Oyster Creek retirements in September 2019 and December 2019, respectively. EGTP removal impacts partial year 2017 and full year 2018 and 2019.

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

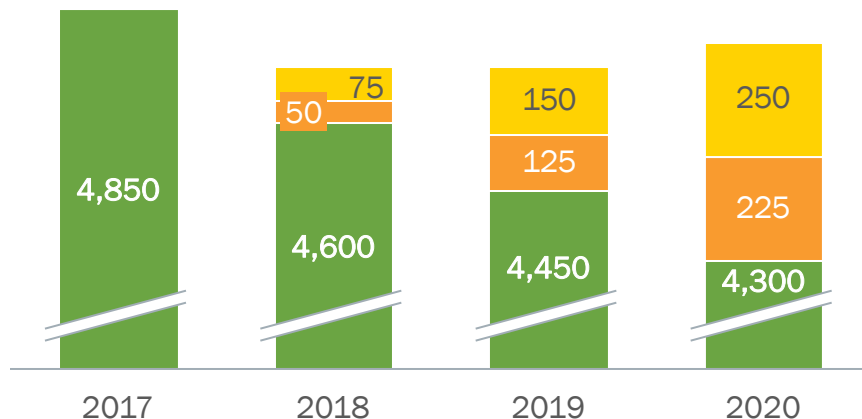
# Cost Management is Integral to Our Business Strategy

## ExGen and BSC Cost Reductions Since Constellation Merger



## ExGen Forecast O&M\* Q3 2017 (\$M)<sup>(1)</sup>

Cost Reductions EGTP & TMI ExGen Total O&M



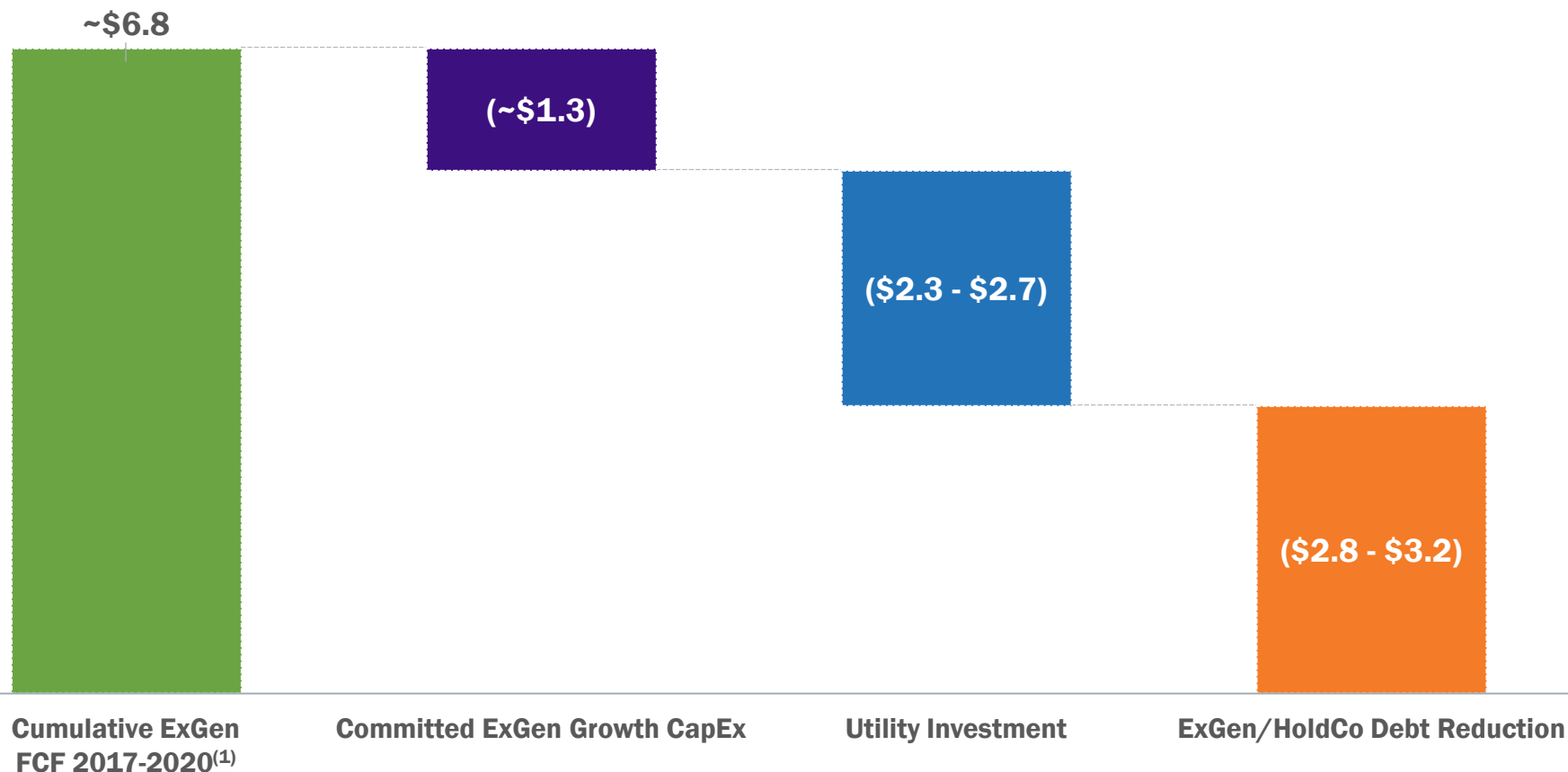
(1) Adjusted for TMI retirement and removal of EGTP, net of other expenses

## ExGen Forecast O&M\*: Q3 2017 vs. Q4 2016<sup>(1)</sup>

ExGen O&M (\$M)	2017	2018	2019	2020	2017-2020 CAGR
Q4 2016 O&M	\$4,850	\$4,725	\$4,725	\$4,775	- 0.5%
EGTP & TMI	(\$0)	(\$50)	(\$125)	(\$225)	-
Q4 '16 O&M, Net of EGTP & TMI	\$4,850	\$4,675	\$4,600	\$4,550	-2.1%
Cost Savings	(\$0)	(\$75)	(\$150)	(\$250)	-
Q3 2017 O&M	\$4,850	\$4,600	\$4,450	\$4,300	-3.9%

# ExGen's Strong Free Cash Flow Supports Utility Growth and Debt Reduction

## 2017-2020 Exelon Generation Free Cash Flow\* and Uses of Cash (\$B)



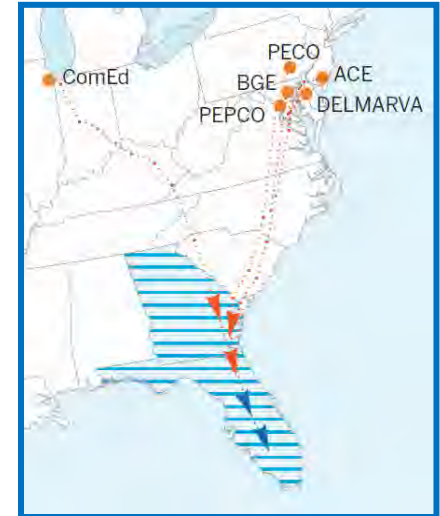
**Redeploying Exelon Generation's free cash flow to maximize shareholder value**

(1) Sources include change in margin, tax parent benefit, equity investments, and acquisitions and divestitures



# Hurricane Support

- More than 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
  - Exelon teams shared our experience with severe weather restoration efforts and industry-leading best practices to lead one of the largest contingents of support nationally
  - Crews deployed for more than two weeks helping to restore power to nearly eight million customers in Florida and Georgia
- Approximately 250 Exelon employee volunteers logged over 1,300 hours for disaster relief activities
- Exelon and its employees contributed approximately \$820,000 in disaster relief



# The Exelon Value Proposition

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- **Regulated Utility Growth** with utility EPS rising 6-8% annually from 2017-2020 and rate base growth of 6.5%, 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 2020 planning horizon
- **Capital allocation priorities targeting:**
  - Organic utility growth;
  - Return of capital to shareholders with 2.5% annual dividend growth through 2018<sup>(1)</sup>,
  - Debt reduction; and
  - Modest contracted generation investments

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

# **Additional Disclosures**

# 2017 Projected Sources and Uses of Cash

(\$M) <sup>(1)</sup>	BGE	ComEd	PECO	PHI	Total Utilities	ExGen	Corp <sup>(8)</sup>	Exelon 2017E	Cash Balance
<b>Beginning Cash Balance</b> * <sup>(2)</sup>									<b>1,050</b>
Adjusted Cash Flow from Operations* <sup>(2)</sup>	775	1,025	750	1,175	3,750	3,350	75	7,150	
Base CapEx and Nuclear Fuel <sup>(3)</sup>	0	0	0	0	0	(1,950)	(50)	(2,025)	
<b>Free Cash Flow*</b>	<b>775</b>	<b>1,025</b>	<b>750</b>	<b>1,175</b>	<b>3,750</b>	<b>1,375</b>	<b>0</b>	<b>5,125</b>	
Debt Issuances	300	1,000	325	200	1,825	750	1,150	3,725	
Debt Retirements	(300)	(425)	0	(150)	(875)	(700)	(1,700)	(3,275)	
Project Financing	n/a	n/a	n/a	n/a	n/a	275	n/a	275	
Equity Issuance/Share Buyback	0	0	0	0	0	0	1,150	1,150	
Contribution from Parent	175	675	0	800	1,650	0	(1,625)	25	
Other Financing <sup>(4)</sup>	150	350	150	(375)	275	50	425	725	
<b>Financing</b> * <sup>(5)</sup>	<b>350</b>	<b>1,600</b>	<b>475</b>	<b>450</b>	<b>2,875</b>	<b>350</b>	<b>(625)</b>	<b>2,625</b>	
<b>Total Free Cash Flow and Financing</b>	<b>1,125</b>	<b>2,625</b>	<b>1,225</b>	<b>1,650</b>	<b>6,600</b>	<b>1,750</b>	<b>(600)</b>	<b>7,750</b>	
Utility Investment	(925)	(2,200)	(775)	(1,375)	(5,250)	0	0	(5,250)	
ExGen Growth <sup>(3,6)</sup>	0	0	0	0	0	(800)	0	(800)	
Acquisitions and Divestitures	0	0	0	0	0	0	0	0	
Equity Investments	0	0	0	0	0	(50)	0	(50)	
Dividend <sup>(7)</sup>	0	0	0	0	0	0	(1,225)	(1,225)	
<b>Other CapEx and Dividend</b>	<b>(925)</b>	<b>(2,200)</b>	<b>(775)</b>	<b>(1,375)</b>	<b>(5,250)</b>	<b>(875)</b>	<b>(1,225)</b>	<b>(7,350)</b>	
<b>Total Cash Flow</b>	<b>200</b>	<b>450</b>	<b>450</b>	<b>250</b>	<b>1,350</b>	<b>875</b>	<b>(1,850)</b>	<b>400</b>	
<b>Ending Cash Balance</b> * <sup>(2)</sup>									<b>1,450</b>

- (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 includes primarily expected changes in short-term debt, money pool borrowings, tax sharing from the parent, debt issue costs, CENG borrowing from Sumitomo, tax equity cash flows, capital leases, and renewable JV proceeds
- (5) Financing cash flow excludes intercompany dividends and other intercompany financing activities
- (6) ExGen Growth CapEx primarily includes Texas CCGTs, AGE, 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 \$5.1B of free cash flow, including \$1.4B at ExGen and \$3.8B at the Utilities

## Supported by a strong balance sheet

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

- ✓ \$0.9B of long-term debt at the utilities, net of refinancing, to support continued growth

## Enable growth & value creation

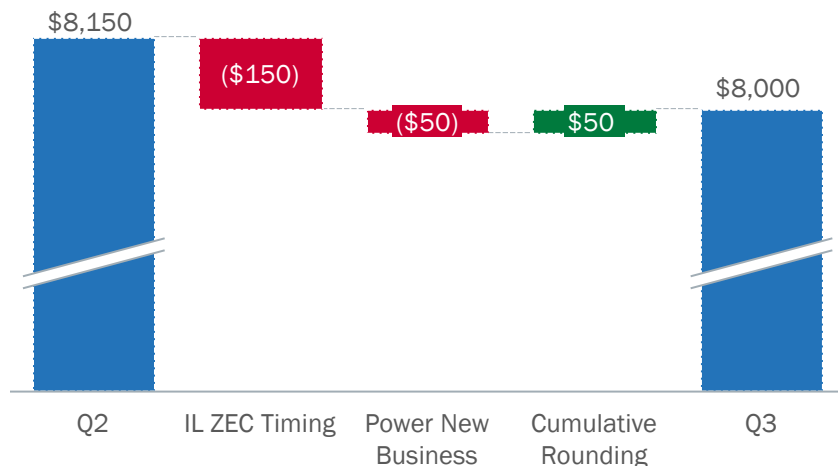
*Creating value for customers, communities and shareholders*

- ✓ Investing \$6.1B, with \$5.3B at the Utilities and \$0.8B at ExGen

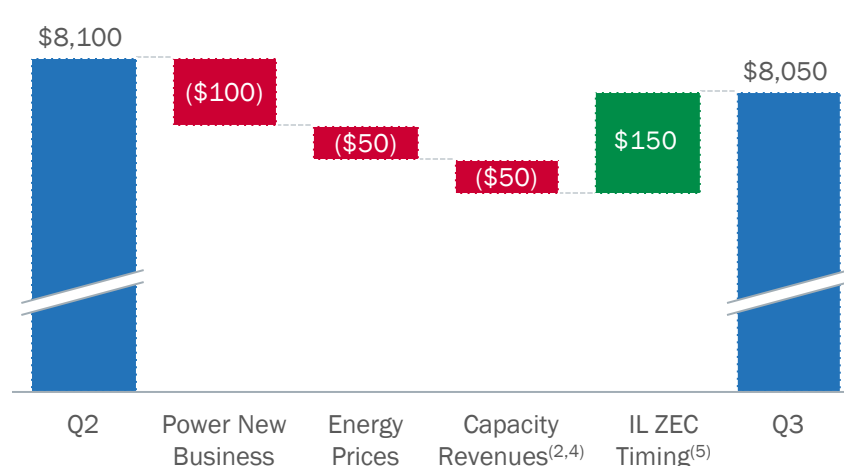
Note: Numbers may not add due to rounding

# ExGen Forward Total Gross Margin\* Walk: Q3 2017 vs. Q2 2017

## FY 2017 (\$M)<sup>(1,3,4)</sup>



## FY 2018 (\$M)<sup>(1,3,4)</sup>



## FY 2019 (\$M)<sup>(1,3,4)</sup>



## Key Takeaways

- Change in timing of Illinois ZEC contract finalization results in 2017 reduction of \$150M on a rounded basis and 2018 increase of \$150M
- Aggressive bidding by market participants in a low volatility period is pressuring Wholesale margins and limiting C&I Retail growth; reduce Power New Business To Go by \$100M in 2018 and 2019 to reflect continuation of current, low discipline market bidding behavior
- Lower energy prices reduce Open Gross Margin by \$50M in 2018 and 2019; October price recovery offsets 2019 declines
- Lower observed capacity prices in NY and MISO reduce Capacity Revenues by \$50M on a rounded basis in 2018 and 2019

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

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

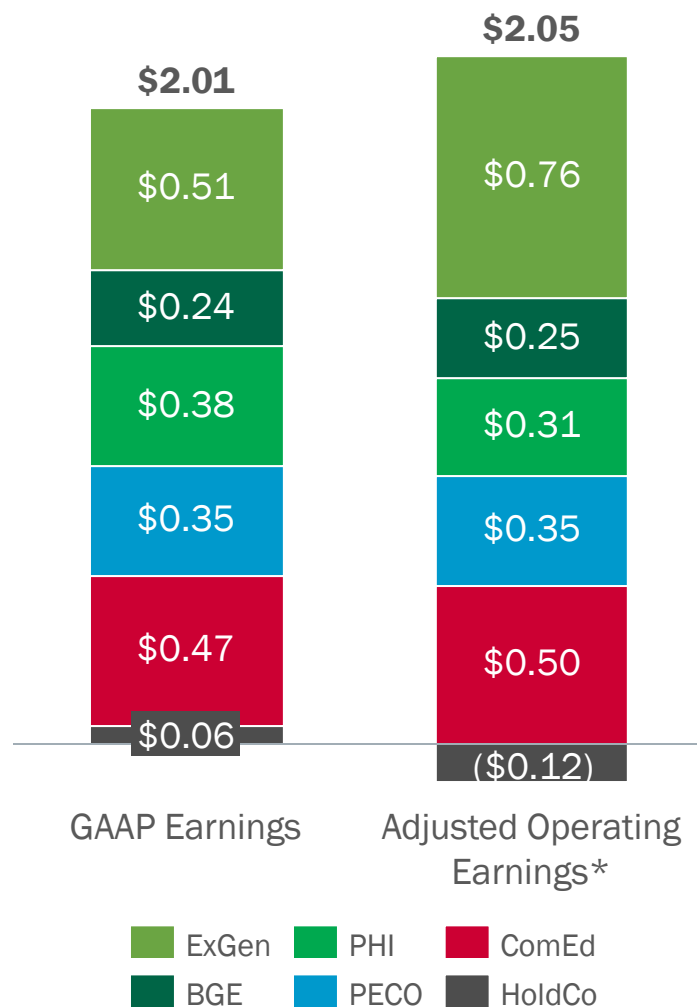
(3) Based on September 30, 2017, market conditions

(4) Reflects TMI and Oyster Creek retirements in September 2019 and December 2019, respectively

(5) 2018 includes \$150M of IL ZEC revenues associated with 2017 production

# YTD Earnings Results

## YTD 2017 EPS Results

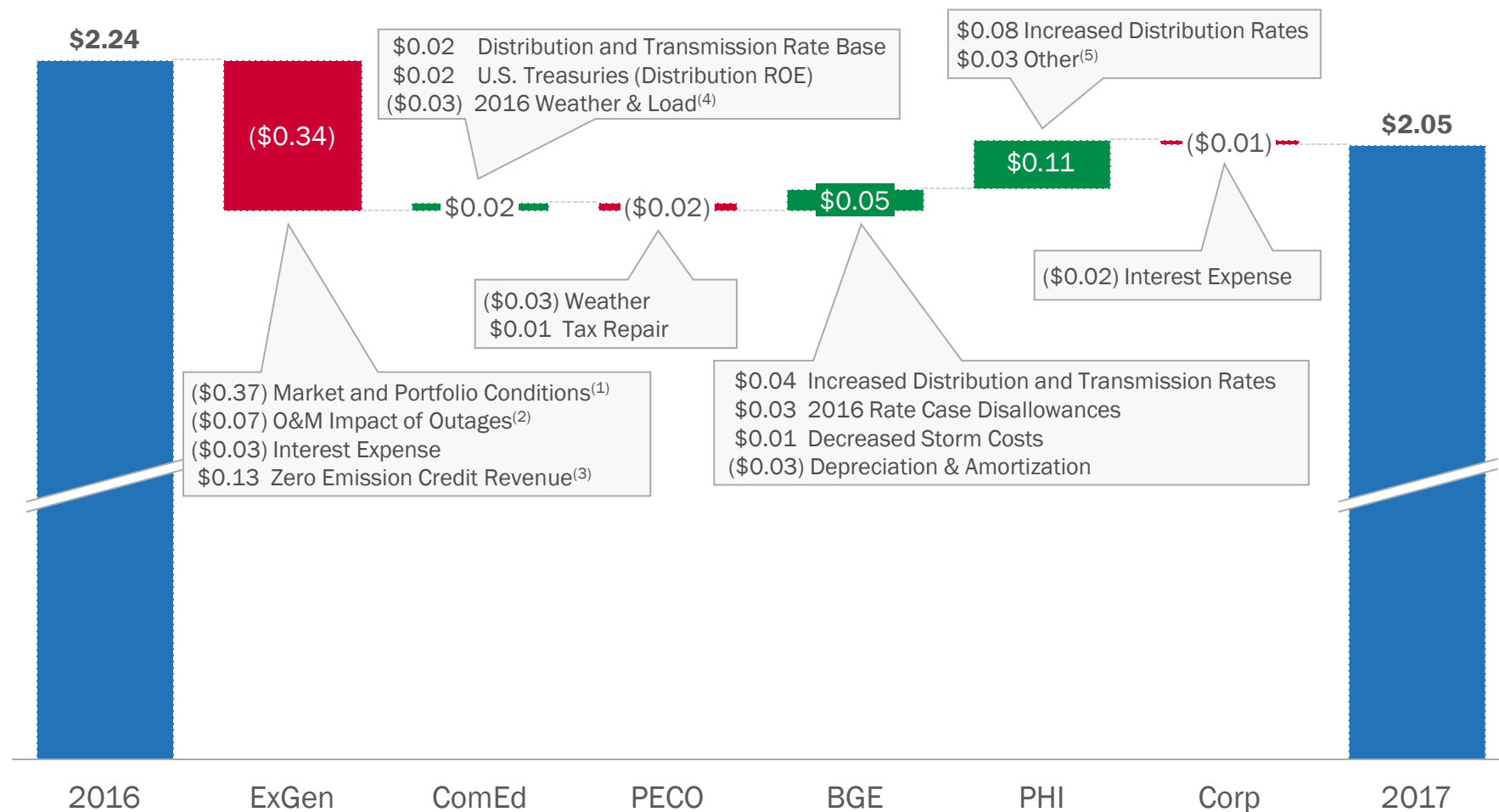


- GAAP earnings were \$2.01/share YTD 2017 vs. \$1.00/share YTD 2016
- Adjusted operating earnings\* were \$2.05/share YTD 2017 vs. \$2.24/share YTD 2016

Note: Amounts may not sum due to rounding

\* Refer to pages 3 and 4 for information regarding non-GAAP financial measures

# YTD Adjusted Operating Earnings\* Waterfall



Note: Amounts may not sum due to rounding

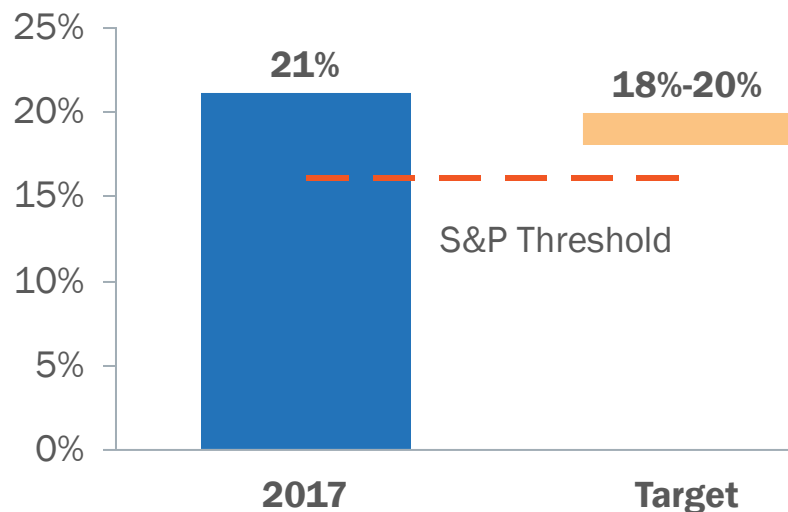
- (1) Includes the unfavorable impact of the conclusion of the Ginna Reliability Support Services Agreement, the impacts of declining natural gas prices on Generation's natural gas portfolio, the impacts of lower load volumes delivered due to mild weather and lower realized energy prices related to Exelon's ratable hedging strategy
- (2) Driven by higher planned nuclear outages in 2017; excludes Salem
- (3) Reflects the impact of the New York Clean Energy Standard
- (4) Pursuant to the Illinois Future Energy Jobs Act, beginning in 2017, customer rates for ComEd are adjusted to eliminate the favorable and unfavorable impacts of weather and customer usage patterns on distribution volumes
- (5) PHI reflects full nine months of earnings in 2017 versus earnings from March 24, 2016, through September 30, 2016

# Maintaining Strong Investment Grade Credit Ratings is a Top Financial Priority

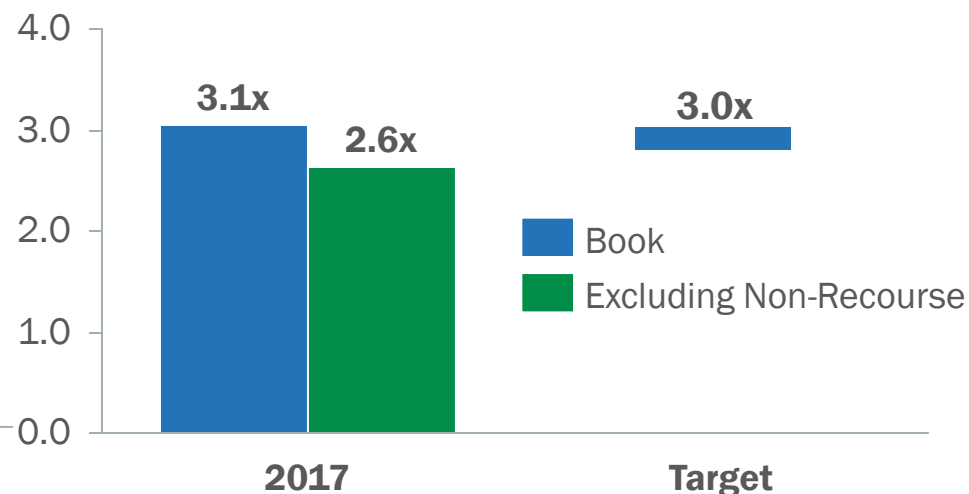
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## Exelon S&P FFO/Debt %\*(1,4,6,7)



## ExGen Debt/EBITDA Ratio\*(5,6,7)



## Credit Ratings by Operating Company

Current Ratings <sup>(2,3)</sup>	ExCorp	ExGen	ComEd	PECO	BGE	ACE	DPL	Pepco
<b>Moody's</b>	Baa2	Baa2	A1	Aa3	A3	A3	A2	A2
<b>S&amp;P</b>	BBB-	BBB	A-	A-	A-	A	A	A
<b>Fitch</b>	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 October 24, 2017, 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

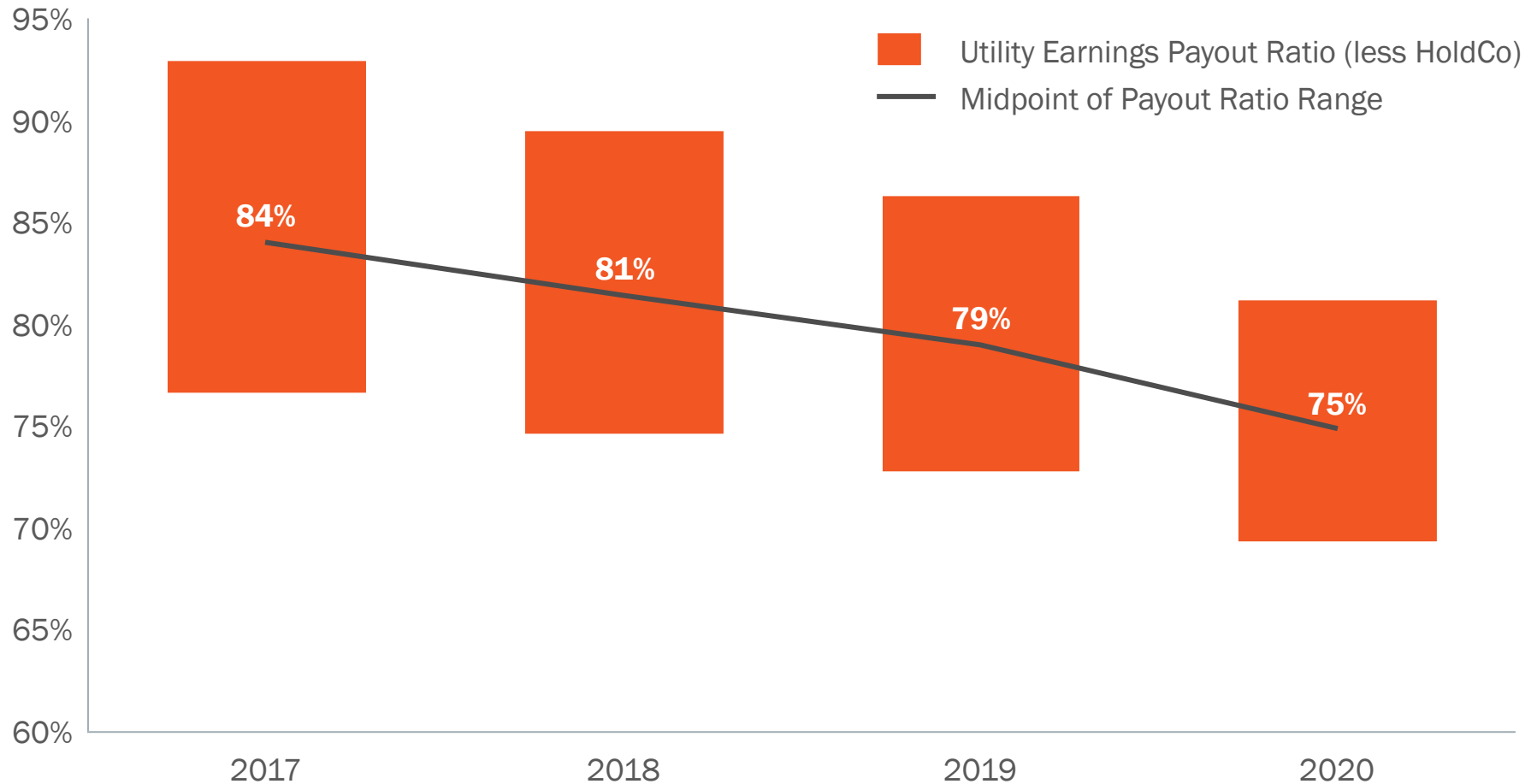
(5) Reflects net book debt (YE debt less cash on hand) / adjusted operating EBITDA\*

(6) Reflects removal of EGTP

(7) Reflects delay in Illinois ZEC revenue recognition from 2017 to 2018



# Theoretical Dividend Affordability from Utility less HoldCo<sup>(1,2)</sup>



**Utility less HoldCo payout ratio falling consistently even as dividend grows**

- (1) Chart is illustrative and shows theoretical payout ratio if utilities supported 100% of the external dividend and interest expense at HoldCo. Currently, the utilities have a payout ratio of 70% which covers the majority of the external dividend and interest expense at HoldCo with ExGen covering the remainder.
- (2) Board of directors has approved a policy of 2.5% per year dividend increase through 2018. For illustrative purposes only, the chart assumes the dividend continues to increase 2.5% per year through 2020, although the board has not yet established dividend policy for periods after 2018. Quarterly dividends are subject to declaration by the board of directors.

# **Exelon Generation Disclosures**

**September 30, 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

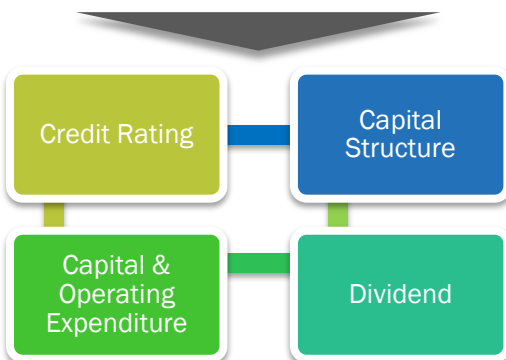
- Ensure stability in near-term cash flows and earnings
- Disciplined approach to hedging
- Tenor aligns with customer preferences and market liquidity
- Multiple channels to market that allow us to maximize margins
- Large open position in outer years to benefit from price upside

## Bull / Bear Program

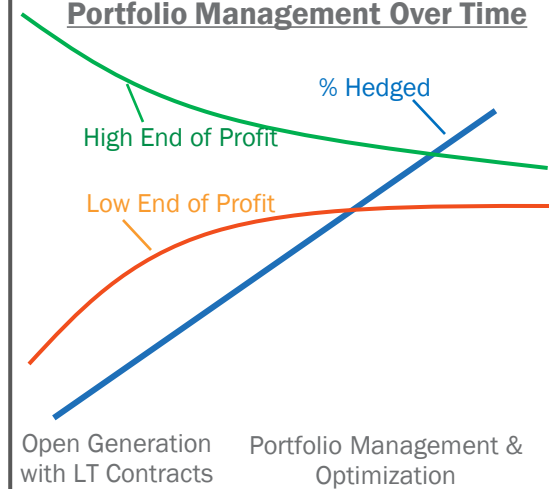
- Ability to exercise fundamental market views to create value within the ratable framework
- Modified timing of hedges versus purely ratable
- Cross-commodity hedging (heat rate positions, options, etc.)
- Delivery locations, regional and zonal spread relationships

## Align Hedging & Financials

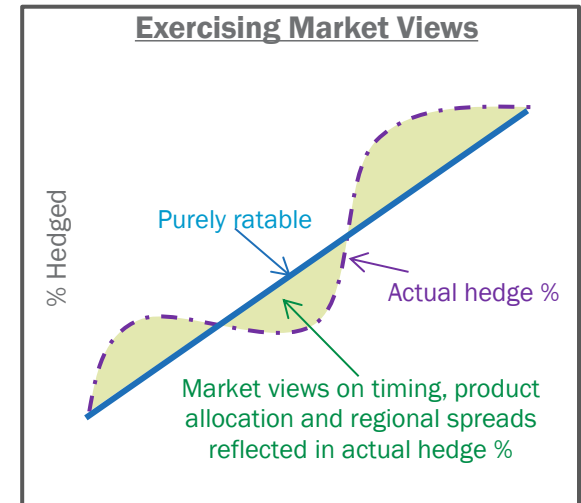
### Establishing Minimum Hedge Targets



## 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<sup>(1)</sup>)

### Capacity and ZEC Revenues

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

### MtM of Hedges<sup>(2)</sup>

- 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<sup>(5)</sup>

## Gross margin from other business activities

### “Non Power” Executed

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

### “Non Power” New Business

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

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) <sup>(1)</sup>	2017	2018	2019
Open Gross Margin (including South, West & Canada hedged GM) <sup>(2,5)</sup>	\$3,600	\$3,900	\$3,700
Capacity and ZEC Revenues <sup>(2,5,6)</sup>	\$1,700	\$2,300	\$2,000
Mark-to-Market of Hedges <sup>(2,3)</sup>	\$2,150	\$650	\$450
Power New Business / To Go	\$100	\$700	\$850
Non-Power Margins Executed	\$350	\$200	\$100
Non-Power New Business / To Go	\$100	\$300	\$400
<b>Total Gross Margin*<sup>(4,5)</sup></b>	<b>\$8,000</b>	<b>\$8,050</b>	<b>\$7,500</b>

Reference Prices <sup>(4)</sup>	2017	2018	2019
Henry Hub Natural Gas (\$/MMBtu)	\$3.14	\$3.05	\$2.89
Midwest: NiHub ATC prices (\$/MWh)	\$26.52	\$27.45	\$26.36
Mid-Atlantic: PJM-W ATC prices (\$/MWh)	\$28.81	\$30.77	\$29.22
ERCOT-N ATC Spark Spread (\$/MWh) <i>HSC Gas, 7.2HR, \$2.50 VOM</i>	(\$0.78)	\$1.22	\$2.65
New York: NY Zone A (\$/MWh)	\$24.38	\$27.29	\$26.67
New England: Mass Hub ATC Spark Spread (\$/MWh) <i>ALQN Gas, 7.5HR, \$0.50 VOM</i>	\$4.36	\$3.99	\$4.24

(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 September 30, 2017, market conditions

(5) Reflects ownership of FitzPatrick as of April 1, 2017, and TMI and Oyster Creek retirements in September 2019 and December 2019, respectively. EGTP removal impacts partial year 2017 and full year 2018 and 2019.

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

# ExGen Disclosures

Generation and Hedges	2017	2018	2019
<u>Exp. Gen (GWh)<sup>(1)</sup></u>	<b>200,200</b>	<b>199,300</b>	<b>202,000</b>
Midwest	95,900	95,800	97,000
Mid-Atlantic <sup>(2,6)</sup>	60,700	60,500	59,000
ERCOT	17,800	19,500	20,800
New York <sup>(2,6)</sup>	14,700	15,500	16,600
New England	11,100	8,000	8,600
<u>% of Expected Generation Hedged<sup>(3)</sup></u>	<b>98%-101%</b>	<b>79%-82%</b>	<b>45%-48%</b>
Midwest	97%-100%	74%-77%	41%-44%
Mid-Atlantic <sup>(2,6)</sup>	98%-101%	90%-93%	51%-54%
ERCOT	97%-100%	77%-80%	44%-47%
New York <sup>(2,6)</sup>	99%-102%	71%-74%	43%-46%
New England	103%-106%	86%-89%	52%-55%
<u>Effective Realized Energy Price (\$/MWh)<sup>(4)</sup></u>			
Midwest	\$33.00	\$29.50	\$29.50
Mid-Atlantic <sup>(2,6)</sup>	\$44.00	\$37.00	\$39.00
ERCOT <sup>(5)</sup>	\$11.00	\$3.50	\$3.50
New York <sup>(2,6)</sup>	\$41.50	\$37.50	\$32.00
New England <sup>(5)</sup>	\$20.00	\$2.50	\$3.00

(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 15 refueling outages in 2017, 15 in 2018, and 11 in 2019 at Exelon-operated nuclear plants and Salem. Expected generation assumes capacity factors of 93.4%, 93.2% and 94.7% in 2017, 2018, and 2019, respectively at Exelon-operated nuclear plants, at ownership. These estimates of expected generation in 2018 and 2019 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

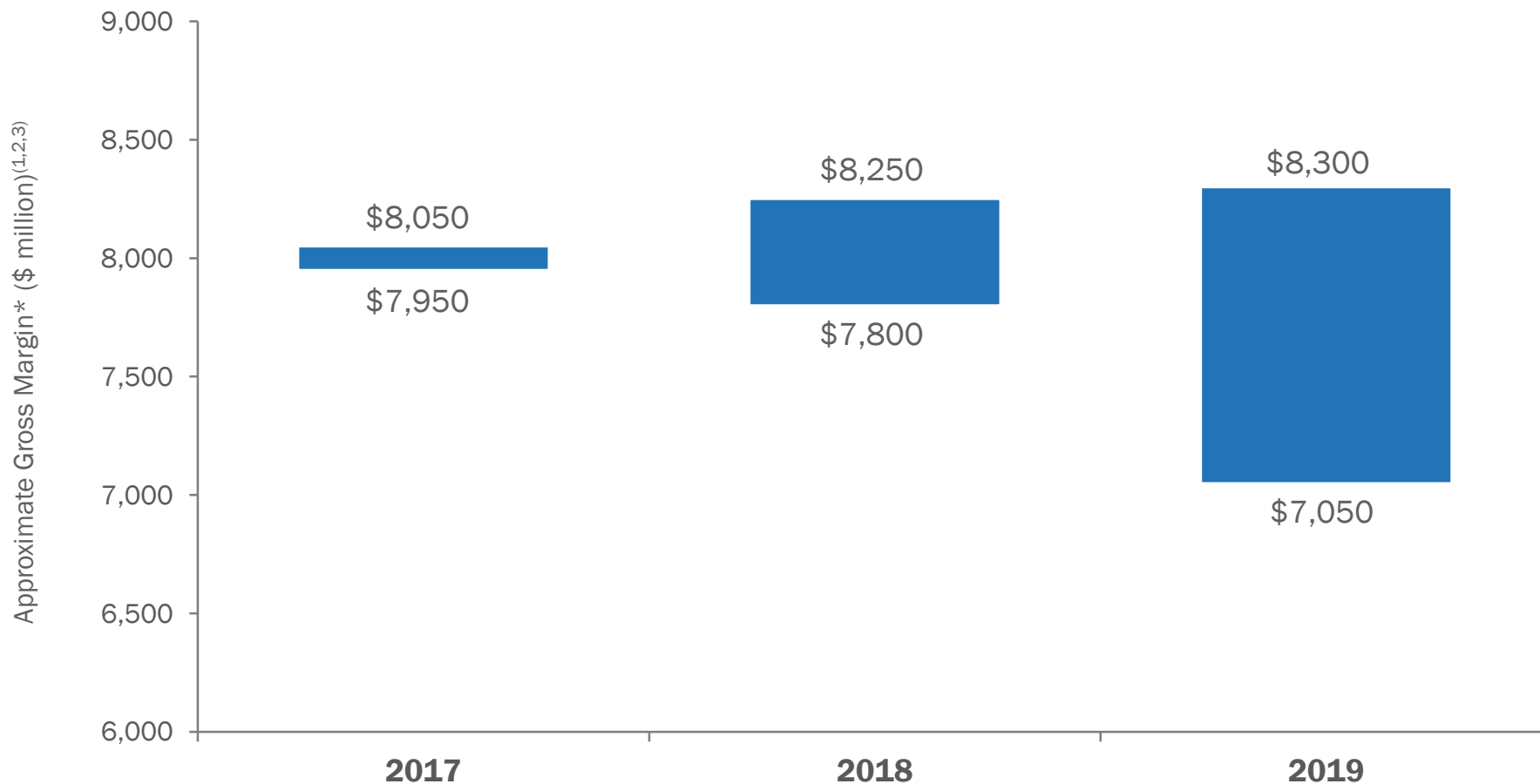
(6) Reflects ownership of FitzPatrick as of April 1, 2017, and TMI and Oyster Creek retirements in September 2019 and December 2019, respectively. EGTP removal impacts partial year 2017 and full year 2018 and 2019.

# ExGen Hedged Gross Margin\* Sensitivities

Gross Margin* Sensitivities (with existing hedges) <sup>(1)</sup>	2017	2018	2019
Henry Hub Natural Gas (\$/MMBtu)			
+ \$1/MMBtu	\$(20)	\$140	\$515
- \$1/MMBtu	\$(10)	\$(210)	\$(500)
NiHub ATC Energy Price			
+ \$5/MWh	-	\$120	\$265
- \$5/MWh	-	\$(115)	\$(265)
PJM-W ATC Energy Price			
+ \$5/MWh	-	\$10	\$150
- \$5/MWh	\$5	\$(40)	\$(145)
NYPP Zone A ATC Energy Price			
+ \$5/MWh	-	\$25	\$40
- \$5/MWh	-	\$(20)	\$(45)
Nuclear Capacity Factor			
+/- 1%	+/- \$10	+/- \$35	+/- \$35

(1) Based on September 30, 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 2018 and 2019 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 September 30, 2017
- (2) Gross Margin Upside/Risk based on commodity exposure which includes open generation and all committed transactions
- (3) Reflects ownership of FitzPatrick as of April 1, 2017, and TMI and Oyster Creek retirements in September 2019 and December 2019, respectively. EGTP removal impacts partial year 2017 and full year 2018 and 2019.



# Illustrative Example of Modeling Exelon Generation 2018 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	<div>← \$3.9 billion →</div>					
(B)	Capacity and ZEC	<div>← \$2.3 billion →</div>					
(C)	Expected Generation (TWh)	95.8	60.5	19.5	15.5	8.0	
(D)	Hedge % (assuming mid-point of range)	75.5%	91.5%	78.5%	72.5%	87.5%	
(E=C*D)	Hedged Volume (TWh)	72.3	55.4	15.3	11.2	7.0	
(F)	Effective Realized Energy Price (\$/MWh)	\$29.50	\$37.00	\$3.50	\$37.50	\$2.50	
(G)	Reference Price (\$/MWh)	\$27.45	\$30.77	\$1.22	\$27.29	\$3.99	
(H=F-G)	Difference (\$/MWh)	\$2.05	\$6.23	\$2.28	\$10.21	(\$1.49)	
(I=E*H)	Mark-to-Market value of hedges (\$ million) <sup>(1)</sup>	\$150	\$345	\$35	\$115	(\$10)	
(J=A+B+I)	Hedged Gross Margin (\$ million)	\$6,850					
(K)	Power New Business / To Go (\$ million)	\$700					
(L)	Non-Power Margins Executed (\$ million)	\$200					
(M)	Non-Power New Business / To Go (\$ million)	\$300					
(N=J+K+L+M)	Total Gross Margin <sup>*</sup>	\$8,050 million					

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

# Additional ExGen Modeling Data

Total Gross Margin Reconciliation (in \$M) <sup>(1)</sup>	2017	2018	2019
<b>Revenue Net of Purchased Power and Fuel Expense<sup>*(2,3)</sup></b>	<b>\$8,575</b>	<b>\$8,575</b>	<b>\$8,025</b>
Non-cash amortization of intangible assets, net, related to commodity contracts recorded at fair value at merger date	\$50	-	-
Other Revenues <sup>(4)</sup>	\$(150)	\$(200)	\$(200)
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses	\$(475)	\$(325)	\$(325)
<b>Total Gross Margin* (Non-GAAP)</b>	<b>\$8,000</b>	<b>\$8,050</b>	<b>\$7,500</b>

Key ExGen Modeling Inputs (in \$M) <sup>(1,5)</sup>	2017
Other <sup>(6)</sup>	\$175
Adjusted O&M*	\$(4,850)
Taxes Other Than Income (TOTI) <sup>(7)</sup>	\$(400)
Depreciation & Amortization <sup>(8)</sup>	\$(1,075)
Interest Expense <sup>(9)</sup>	\$(400)
<b>Effective Tax Rate</b>	<b>32.0%</b>

(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, 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 \$125M

(8) Excludes P&L neutral decommissioning depreciation

(9) Interest expense includes impact of reduced capitalized interest due to Texas CCGT plants in service as of May and June of 2017. Capitalized interest will be an additional ~\$25M lower in 2018 as well due to this.

# **Exelon Utilities' Rate Case Filing Summaries**

# Exelon Utilities' Distribution Rate Case Schedule

	9/17	10/17	11/17	12/17	1/18	2/18	3/18
<b>ACE Electric Distribution Rates - NJ</b>	Settlement approved by NJBPU Sept 22						
<b>Pepco Electric Distribution Rates - MD</b>	Evidentiary Hearings Sept 5-15	Commission Order Received Oct 20					
<b>ComEd Electric Distribution Formula Rate</b>		Proposed Order Oct 19		Commission Order Expected Dec 9			
<b>Delmarva – MD Electric Distribution Rates</b>		Intervenor Direct Testimony Oct 16	Rebuttal Testimony Nov 16	Evidentiary Hearing Dec 11-20		Commission Order Expected Feb 14	
<b>Delmarva – DE Electric Distribution Rates</b>				Intervenor Direct Testimony Dec 6	Rebuttal Testimony Jan 12	Evidentiary Hearing Feb 20-22	
<b>Delmarva – DE Gas Distribution Rates</b>					Intervenor Direct Testimony Jan 16		Rebuttal Testimony Mar 5

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

# Delmarva DE (Gas) Distribution Rate Case Filing

<b>Docket No.</b>	17-0978
<b>Test Year</b>	January 1, 2017 – December 31, 2017
<b>Test Period</b>	3 months actual and 9 months estimated
<b>Requested Common Equity Ratio</b>	50.52%
<b>Requested Rate of Return</b>	ROE: 10.10%; ROR: 6.98%
<b>Proposed Rate Base (Adjusted)</b>	\$348M
<b>Requested Revenue Requirement Increase</b>	\$12.9M <sup>(1)</sup>
<b>Residential Total Bill % Increase</b>	9.9%
<b>Notes</b>	<ul style="list-style-type: none"> <li>• August 17, 2017, Delmarva DE filed application with Delaware Public Service Commission (DPSC) seeking increase in gas distribution base rates</li> <li>• Size of ask is driven by continued investments in gas distribution system to maintain and increase reliability and customer service</li> <li>• Forward looking reliability plant additions through August 2018 (\$1.0M of Revenue Requirement based on 10.10% ROE) included in revenue requirement request</li> </ul> <p>Procedural Schedule</p> <ul style="list-style-type: none"> <li>• Intervenor Direct Testimony Due: January 16, 2018</li> <li>• Rebuttal Testimony Due: March 5, 2018</li> <li>• Evidentiary Hearings: April 24-26, 2018</li> <li>• Initial Briefs Due: May 14, 2018</li> <li>• Reply Briefs Due: May 29, 2018</li> <li>• Commission Order Expected: Q3 2018</li> </ul>

(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

<b>Docket No.</b>	17-0977
<b>Test Year</b>	January 1, 2017 – December 31, 2017
<b>Test Period</b>	3 months actual and 9 months estimated
<b>Requested Common Equity Ratio</b>	50.52%
<b>Requested Rate of Return</b>	ROE: 10.10%; ROR: 6.98%
<b>Proposed Rate Base (Adjusted)</b>	\$805M
<b>Requested Revenue Requirement Increase</b>	\$31.2M <sup>(1)</sup>
<b>Residential Total Bill % Increase</b>	4.6%
<b>Notes</b>	<ul style="list-style-type: none"> <li>• August 17, 2017, Delmarva DE filed application with DPSC seeking increase in electric distribution base rates</li> <li>• Size of ask is driven by continued investments in electric distribution system to maintain and increase reliability and customer service</li> <li>• Forward looking reliability plant additions through August 2018 (\$3.1M of Revenue Requirement based on 10.10% ROE) included in revenue requirement request</li> <li>• Potential delay due to Staff and Division of the Public Advocate (DPA) joint motion to dismiss the application, which states that the increase of the requested increase to \$31.2 million required additional time to review</li> </ul> <p>Procedural Schedule:</p> <ul style="list-style-type: none"> <li>• Intervenor Direct Testimony Due: December 6, 2017</li> <li>• Rebuttal Testimony Due: January 12, 2018</li> <li>• Evidentiary Hearings: February 20-22, 2018</li> <li>• Initial Briefs Due: March 16, 2018</li> <li>• Reply Briefs Due: March 30, 2018</li> <li>• Commission Order Expected: Q3 2018</li> </ul>

(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

<b>Formal Case No.</b>	9455
<b>Test Year</b>	October 1, 2016 – September 30, 2017
<b>Test Period</b>	7 months actual and 5 months estimated
<b>Requested Common Equity Ratio</b>	50.68%
<b>Requested Rate of Return</b>	ROE: 10.10%; ROR: 7.05%
<b>Proposed Rate Base (Adjusted) (Updated on Sept. 28, 2017)</b>	\$775M
<b>Requested Revenue Requirement Increase (Updated on Sept. 28, 2017)</b>	\$21.6M <sup>(1)</sup>
<b>Residential Total Bill % Increase</b>	1.8%
<b>Notes</b>	<ul style="list-style-type: none"> <li>• July 14, 2017, Delmarva MD filed application with Maryland Public Service Commission (MDPSC) seeking increase in electric distribution base rates</li> <li>• 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</li> </ul> <p>Intervenor Positions:</p> <ul style="list-style-type: none"> <li>• Office of People's Council (OPC) revenue increase of \$5.0M or \$7.2M based on 8.65% or 9.0% ROE, respectively</li> <li>• Staff revenue increase of \$11.1M based on 9.30% ROE</li> </ul> <p>Procedural Schedule:</p> <ul style="list-style-type: none"> <li>• Intervenor Direct Testimony Due: October 16, 2017</li> <li>• Rebuttal Testimony Due: November 16, 2017</li> <li>• Evidentiary Hearings: December 11 – 20, 2017</li> <li>• Briefs due: January 9, 2018</li> <li>• Commission Order Expected: February 14, 2018</li> </ul>

(1) Amount represents adjusted requested revenue requirement filed on September 28, 2017

# ComEd April 2017 Distribution Formula Rate

The 2017 distribution formula rate filing established the net revenue requirement used to set the rates that will take effect in January 2018 after the Illinois Commerce Commission's (ICC's) review. There are two components to the annual distribution formula rate filing:

- **Filing Year:** Based on 2016 costs and 2017 projected plant additions
- **Annual Reconciliation:** For 2016, this amount reconciles the revenue requirement reflected in rates in effect during 2016 to the actual costs for that year. The annual reconciliation impacts cash flow in 2018 but the earnings impact has been recorded in 2016 as a regulatory asset.

<b>Docket #</b>	<b>17-0196</b>
<b>Filing Year</b>	<b>2016 Calendar Year Actual Costs and 2017 Projected Net Plant Additions</b> 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.
<b>Reconciliation Year</b>	<b>Reconciles Revenue Requirement reflected in rates during 2016 to 2016 Actual Costs Incurred.</b> Revenue requirement for 2016 is based on docket 15-0287 (2014 actual costs and 2015 projected net plant additions) approved in December 2015.
<b>Common Equity Ratio</b>	<b>~46%</b> for both the filing and reconciliation year
<b>ROE</b>	<b>8.40%</b> for the filing year (2016 30-yr Treasury Yield of 2.60% + 580 basis point risk premium) and <b>8.34%</b> for the reconciliation year (2016 30-yr Treasury Yield of 2.60% + 580 basis point risk premium – 6 basis points performance metrics penalty). For 2017 and 2018, the actual allowed ROE reflected in net income will ultimately be based on the average of the 30-year Treasury Yield during the respective years plus 580 basis point spread, absent any metric penalties
<b>Requested Rate of Return</b>	<b>~6.5%</b> for both the filing and reconciliation years
<b>Rate Base<sup>(1)</sup></b>	<b>\$9,662 million</b> – 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. <b>\$8,807 million</b> - Reconciliation year (represents year-end rate base for 2016)
<b>Revenue Requirement Increase<sup>(1)</sup></b>	<b>\$95.6M increase</b> (\$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.
<b>Timeline</b>	<ul style="list-style-type: none"> <li>• 04/13/17 Filing Date</li> <li>• 240 Day Proceeding</li> <li>• ICC Order expected to be issued by December 9, 2017</li> </ul>

**Given the retroactive ratemaking provision in the Energy Infrastructure Modernization Act (EIMA) legislation, ComEd net income during the year will be based on actual costs with a regulatory asset/liability recorded to reflect any under/over recovery reflected in rates. Revenue Requirement in rate filings impacts cash flow.**

(1) Amount represents ComEd's position filed in Rebuttal testimony on July 21, 2017



# Pepco MD Distribution Rate Case Final Order

Formal Case No.	9443	Per Commission Order
Test Year	May 1, 2016 – April 30, 2017	
Test Period	8 months actual and 4 months estimated (Updated on August 24, 2017)	
Requested Common Equity Ratio	50.15%	50.15%
Requested Rate of Return	ROE: 10.10%; ROR: 7.74%	ROE: 9.50%; ROR: 7.43%
Proposed Rate Base (Adjusted)	\$1.7B	\$1.6B
Requested Revenue Requirement Increase	\$67.0M	\$32.4M
Residential Total Bill % Increase	5.6%	2.99%
Notes	<ul style="list-style-type: none"><li>March 24, 2017, Pepco MD filed application with MDPSC seeking increase in electric distribution base rates</li><li>Normalization of tax benefits on pre-1981 removal costs</li><li>8 month forward looking reliability and other plant additions from May 2017 through December 2017 (\$13.3M of Revenue Requirement based on 10.10% ROE) included in revenue requirement request</li></ul> Intervenor Positions: <ul style="list-style-type: none"><li>Office of People’s Council (OPC) revenue increase of \$9.95M or \$13.44M based on 8.75% or 9.0% ROE, respectively</li><li>Apartment and Office Building Association (AOBA) revenue increase of \$24.76M based on 9.10% ROE</li><li>Commission Technical Staff (Staff) revenue increase of \$25.76M based on 9.39% ROE</li><li>Commission Order Expected: October 20, 2017</li></ul>	<ul style="list-style-type: none"><li>Order received on October 20th</li><li>Two months of post-test period reliability capital placed in service through June 2017 approved</li><li>Remaining deferred balance of storm costs for Sandy and Derecho to be amortized over 12 months</li><li>Expansion of test year to a minimum of 6 months of forecasted data was denied</li><li>Pepco’s proposal to normalize tax benefits for pre-1981 removal costs to be addressed in the next base rate case</li><li>Approximately \$400K of AIP expense was excluded from recovery as a result of the Company not achieving its 2016 SAIFI merger target</li></ul>

# Atlantic City Electric NJ Rate Case Final Order

<b>BPU Docket No.</b>	ER17030308	<b>Per Settlement</b>
<b>Test Year</b>	August 1, 2016 – July 31, 2017 (Updated on July 14, 2017)	
<b>Test Period</b>	5 months actual and 7 months forecasted	
<b>Stipulated Common Equity Ratio</b>	Requested 50.14%	50.47%
<b>Stipulated Rate of Return</b>	ROE: 10.10%; ROR: 7.83%	ROE: 9.60% ROR: 7.60%
<b>Stipulated Rate Base (Adjusted)</b>	\$1.4B	\$1.3B
<b>Stipulated Revenue Requirement Increase</b>	\$72.6M	\$43.0M
<b>Stipulated Residential Total Bill % Increase</b>	6.57%	4.03%
<b>Notes</b>	<ul style="list-style-type: none"> <li>• March 30, 2017, Atlantic City Electric filed application with New Jersey Board of Public Utilities (NJBPU) seeking increase in electric distribution base rates</li> <li>• Recovery of investment in infrastructure to maintain and harden electric distribution system</li> <li>• Ratemaking adjustments to address declining sales</li> <li>• Proposal of a Non-Incremental System Renewal Recovery Charge for recovery of non-incremental reliability spend over four years (2018-2021) of \$376M</li> </ul>	<ul style="list-style-type: none"> <li>• Settlement Approved by NJBPU: September 22, 2017</li> <li>• Rate Effective Date: October 1, 2017</li> <li>• Approval for regulatory asset treatment of costs to achieve</li> <li>• Company agreed to withdraw its request to implement a System Renewal Recovery Charge</li> <li>• Company agreed to prepare proposal for phasing out accelerated reliability spending in Reliability Improvement Plan</li> </ul>

# Pepco DC Distribution Rate Case Final Order

<b>Formal Case No.</b>	1139	<b>Per Commission Order</b>
<b>Test Year</b>	April 1, 2015 – March 31, 2016	
<b>Test Period</b>	12 months actual	
<b>Requested Common Equity Ratio</b>	49.14%	49.14%
<b>Requested Rate of Return</b>	ROE: 10.60%; ROR: 8.00%	ROE: 9.50%; ROR: 7.46%
<b>Proposed Rate Base (Adjusted)</b>	\$1.7B	\$1.6B
<b>Requested Revenue Requirement Increase</b>	\$77.5M <sup>(1)</sup>	\$36.9M
<b>Residential Total Bill % Increase</b>	4.62%	2.52%
<b>Notes</b>	<ul style="list-style-type: none"> <li>June 30, 2016, Pepco filed application with District of Columbia Public Service Commission (DCPSC) seeking increase in electric distribution base rates</li> </ul> <p>Intervenor Positions:</p> <ul style="list-style-type: none"> <li>Office of People's Council (OPC) revenue increase of \$25.8M based on 8.60% ROE</li> <li>Apartment and Office Building Association (AOBA) revenue increase of \$62.2M based on 9.25% ROE</li> <li>Healthcare Council of the National Capital Area (HCNCA) revenue increase of \$16.8M based on 8.75% ROE</li> <li>District of Columbia Water and Sewer Authority (DC Water) revenue increase of \$52.7M based on 9.10% ROE</li> </ul>	<ul style="list-style-type: none"> <li>July 25, 2017, DCPSC issued Final Order</li> <li>Bill Stabilization Adjustment (BSA) remains unchanged</li> <li>Approval to establish regulatory asset for costs to achieve (CTA)</li> <li>Customer Base Rate Credit (CBRC) will offset monthly bill increases <ul style="list-style-type: none"> <li>\$15M allocated to residential customers</li> <li>\$2.3M designated to certain small commercial customers</li> <li>\$6-7M reserved for disabled and senior citizens on fixed incomes in future rate cases</li> </ul> </li> <li>Recovery of \$27.4M of AMI, direct load control and dynamic pricing regulatory assets to be amortized over 5 years</li> </ul>

(1) Revenue requirement includes changes in amortization expense, which has no impact on pre-tax earnings

# **Appendix**

## **Reconciliation of Non-GAAP Measures**

# Q3 2016 QTD GAAP EPS Reconciliation

<b>Three Months Ended September 30, 2016</b>	<b>ExGen</b>	<b>ComEd</b>	<b>PECO</b>	<b>BGE</b>	<b>PHI</b>	<b>Other</b>	<b>Exelon</b>
<b>2016 GAAP Earnings (Loss) Per Share</b>	<b>\$0.25</b>	<b>\$0.04</b>	<b>\$0.13</b>	<b>\$0.06</b>	<b>\$0.18</b>	<b>(\$0.13)</b>	<b>\$0.53</b>
Mark-to-market impact of economic hedging activities	(0.06)	-	-	-	-	-	(0.06)
Unrealized gains related to NDT fund investments	(0.07)	-	-	-	-	-	(0.07)
Amortization of commodity contract intangibles	0.01	-	-	-	-	-	0.01
Merger and integration costs	0.01	-	-	-	-	-	0.01
Merger commitments	-	-	-	-	(0.04)	0.05	0.01
Long-Lived asset impairments	0.01	-	-	-	-	-	0.01
Plant retirements and divestitures	0.22	-	-	-	-	-	0.22
Cost management program	0.01	-	-	-	-	-	0.01
Like-kind exchange tax position	-	0.16	-	-	-	0.05	0.21
CENG noncontrolling interest	0.03	-	-	-	-	-	0.03
<b>2016 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share</b>	<b>\$0.41</b>	<b>\$0.20</b>	<b>\$0.13</b>	<b>\$0.06</b>	<b>\$0.14</b>	<b>\$(0.03)</b>	<b>\$0.91</b>

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

# Q3 2017 QTD GAAP EPS Reconciliation

<u>Three Months Ended September 30, 2017</u>	<u>ExGen</u>	<u>ComEd</u>	<u>PECO</u>	<u>BGE</u>	<u>PHI</u>	<u>Other</u>	<u>Exelon</u>
<b>2017 GAAP (Loss) Earnings Per Share</b>	<b>\$0.32</b>	<b>\$0.20</b>	<b>\$0.12</b>	<b>\$0.06</b>	<b>\$0.16</b>	<b>(\$0.00)</b>	<b>\$0.85</b>
Mark-to-market impact of economic hedging activities	(0.05)	-	-	-	-	-	(0.05)
Unrealized gains related to NDT fund investments	(0.07)	-	-	-	-	-	(0.07)
Amortization of commodity contract intangibles	0.01	-	-	-	-	-	0.01
Merger and integration costs	0.01	-	-	-	(0.01)	-	-
Long-lived asset impairments	0.03	-	-	-	-	-	0.03
Plant retirements and divestitures	0.08	-	-	-	-	-	0.08
Cost management program	0.01	-	-	-	-	-	0.01
Reassessment of state deferred income taxes	0.02	-	-	-	-	(0.04)	(0.02)
Bargain purchase gain	(0.01)	-	-	-	-	-	(0.01)
CENG noncontrolling interest	0.02	-	-	-	-	-	0.02
<b>2017 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share</b>	<b>\$0.36</b>	<b>\$0.19</b>	<b>\$0.12</b>	<b>\$0.07</b>	<b>\$0.15</b>	<b>(\$0.04)</b>	<b>\$0.85</b>

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

# Q3 2016 YTD GAAP EPS Reconciliation

<b><u>Nine Months Ended September 30, 2016</u></b>	<b><u>ExGen</u></b>	<b><u>ComEd</u></b>	<b><u>PECO</u></b>	<b><u>BGE</u></b>	<b><u>PHI</u></b>	<b><u>Other</u></b>	<b><u>Exelon</u></b>
<b>2016 GAAP Earnings (Loss) Per Share</b>	<b>\$0.58</b>	<b>\$0.32</b>	<b>\$0.37</b>	<b>\$0.20</b>	<b>(\$0.10)</b>	<b>\$(0.37)</b>	<b>\$1.00</b>
Mark-to-market impact of economic hedging activities	0.07	-	-	-	-	-	0.07
Unrealized gains related to NDT fund investments	(0.13)	-	-	-	-	-	(0.13)
Amortization of commodity contract intangibles	0.01	-	-	-	-	-	0.01
Merger and integration costs	0.02	-	-	-	0.04	0.04	0.10
Merger commitments	-	-	-	-	0.26	0.17	0.43
Long-lived asset impairments	0.11	-	-	-	-	-	0.11
Plant retirements and divestitures	0.37	-	-	-	-	-	0.37
Reassessment of state deferred income taxes	0.01	-	-	-	-	(0.01)	-
Cost management program	0.02	-	-	-	-	-	0.03
Like-kind exchange tax position	-	0.16	-	-	-	0.05	0.21
CENG noncontrolling interest	0.04	-	-	-	-	-	0.04
<b>2016 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share</b>	<b>\$1.10</b>	<b>\$0.48</b>	<b>\$0.37</b>	<b>\$0.20</b>	<b>\$0.20</b>	<b>\$(0.11)</b>	<b>\$2.24</b>

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

# Q3 2017 YTD GAAP EPS Reconciliation

<u>Nine Months Ended September 30, 2017</u>	<u>ExGen</u>	<u>ComEd</u>	<u>PECO</u>	<u>BGE</u>	<u>PHI</u>	<u>Other</u>	<u>Exelon</u>
<b>2017 GAAP Earnings (Loss) Per Share</b>	<b>\$0.51</b>	<b>\$0.47</b>	<b>\$0.35</b>	<b>\$0.24</b>	<b>\$0.38</b>	<b>\$0.06</b>	<b>\$2.01</b>
Mark-to-market impact of economic hedging activities	0.10	-	-	-	-	-	0.10
Unrealized gains related to NDT fund investments	(0.22)	-	-	-	-	-	(0.22)
Amortization of commodity contract intangibles	0.03	-	-	-	-	-	0.03
Merger and integration costs	0.05	-	-	-	(0.01)	-	0.04
Merger commitments	(0.02)	-	-	-	(0.06)	(0.06)	(0.15)
Long-lived asset impairments	0.31	-	-	-	-	-	0.31
Plant retirements and divestitures	0.15	-	-	-	-	-	0.15
Reassessment of state deferred income taxes	0.02	-	-	-	-	(0.06)	(0.04)
Cost management program	0.02	-	-	-	-	-	0.03
Like-kind exchange tax position	-	0.02	-	-	-	(0.05)	(0.03)
Asset retirement obligation	-	-	-	-	-	-	-
Tax settlements	(0.01)	-	-	-	-	-	(0.01)
Bargain purchase gain	(0.25)	-	-	-	-	-	(0.25)
CENG noncontrolling interest	0.08	-	-	-	-	-	0.08
<b>2017 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share</b>	<b>\$0.76</b>	<b>\$0.50</b>	<b>\$0.35</b>	<b>\$0.25</b>	<b>\$0.31</b>	<b>(\$0.12)</b>	<b>\$2.05</b>

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



# GAAP to Operating Adjustments

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- **Exelon's 2017 adjusted (non-GAAP) operating earnings excludes the earnings effects of the following:**
  - Mark-to-market adjustments from economic hedging activities
  - Unrealized gains 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
  - Adjustments to reserves for uncertain tax positions related to the deductibility of certain merger commitments associated with the 2012 CEG and 2016 PHI acquisitions
  - Impairments as a result of the ExGen Texas Power, LLC assets held for sale
  - Plant retirements and divestitures at Generation
  - Non-cash impact of the remeasurement of state deferred income taxes, related to changes in statutory tax rates and changes in forecasted apportionment
  - Costs incurred related to a cost management program
  - Certain adjustments related to Exelon's like-kind exchange tax position
  - Non-cash benefit pursuant to the annual update of the Generation nuclear decommissioning obligation related to the non-regulatory units
  - Benefits related to the favorable settlement of certain income tax positions related to PHI's unregulated business interests
  - The excess of the fair value of assets and liabilities acquired over the purchase price for the FitzPatrick acquisition
  - Generation's noncontrolling interest, primarily related to CENG exclusion items

# GAAP to Non-GAAP Reconciliations

YE 2017 Exelon FFO Calculation (\$M) <sup>(1,2,10,11)</sup>		YE 2017 Exelon Adjusted Debt Calculation (\$M) <sup>(1,2,10)</sup>	
GAAP Operating Income	\$3,500	Long-Term Debt (including current maturities)	\$32,050
Depreciation & Amortization	<u>\$3,350</u>	Short-Term Debt	\$1,125
EBITDA	\$6,850	+ PPA Imputed Debt <sup>(5)</sup>	\$350
+/- Non-operating activities and nonrecurring items <sup>(3)</sup>	\$450	+ Operating Lease Imputed Debt <sup>(6)</sup>	\$875
- Interest Expense	(\$1,450)	+ Pension/OPEB Imputed Debt <sup>(7)</sup>	\$4,100
+ Current Income Tax (Expense)/Benefit	\$325	- Off-Credit Treatment of Debt <sup>(8)</sup>	(\$1,725)
+ Nuclear Fuel Amortization	\$1,075	- Surplus Cash Adjustment <sup>(9)</sup>	(\$600)
+/- Other S&P Adjustments <sup>(4)</sup>	<u>\$350</u>	+/- Other S&P Adjustments <sup>(4)</sup>	<u>(\$650)</u>
<b>= FFO (a)</b>	<b>\$7,600</b>	<b>= Adjusted Debt (b)</b>	<b>\$35,525</b>

YE 2017 Exelon FFO/Debt <sup>(1,2)</sup>		
FFO (a)	=	21%
Adjusted Debt (b)		

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

(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) Includes other adjustments as prescribed by S&P

(5) Reflects present value of net capacity purchases

(6) Reflects present value of minimum future operating lease payments

(7) Reflects after-tax unfunded pension/OPEB

(8) Includes non-recourse project debt

(9) Applies 75% of excess cash against balance of LTD

(10) Reflects removal of EGTP

(11) Reflects delay in Illinois ZEC revenue recognition from 2017 to 2018

# GAAP to Non-GAAP Reconciliations

## YE 2017 ExGen Net Debt Calculation (\$M)<sup>(1,3)</sup>

Long-Term Debt (including current maturities)	\$8,775
Short-Term Debt	\$350
- Surplus Cash Adjustment	<u>(\$300)</u>
<b>= Net Debt (a)</b>	<b>\$8,825</b>

## YE 2017 ExGen Operating EBITDA Calculation (\$M)<sup>(1,3,4)</sup>

GAAP Operating Income	\$775
Depreciation & Amortization	<u>\$1,375</u>
EBITDA	\$2,150
+/- Non-operating activities and nonrecurring items <sup>(2)</sup>	\$725
<b>= Operating EBITDA (b)</b>	<b>\$2,875</b>

## YE 2017 Book Debt / EBITDA

Net Debt (a)		
	=	3.1x
Operating EBITDA (b)		

## YE 2017 ExGen Net Debt Calculation (\$M)<sup>(1,3)</sup>

Long-Term Debt (including current maturities)	\$8,775
Short-Term Debt	\$350
- Surplus Cash Adjustment	<u>(\$300)</u>
- Nonrecourse Debt	<u>(\$1,925)</u>
<b>= Net Debt (a)</b>	<b>\$6,900</b>

## YE 2017 ExGen Operating EBITDA Calculation (\$M)<sup>(1,3,4)</sup>

GAAP Operating Income	\$775
Depreciation & Amortization	<u>\$1,375</u>
EBITDA	\$2,150
+/- Non-operating activities and nonrecurring items <sup>(2)</sup>	\$725
- EBITDA from projects financed by nonrecourse debt	<u>(\$250)</u>
<b>= Operating EBITDA (b)</b>	<b>\$2,625</b>

## YE 2017 Recourse Debt / EBITDA

Net Debt (a)		
	=	2.6x
Operating EBITDA (b)		

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

(2) Reflects impact operating adjustments on GAAP EBITDA

(3) Reflects removal of EGTP

(4) Reflects delay in Illinois ZEC revenue recognition from 2017 to 2018

# GAAP to Non-GAAP Reconciliations

Q3 2017 Operating ROE Reconciliation (\$M) <sup>(1)</sup>	ACE	Delmarva	Pepco	Legacy EXC	Consolidated EU
Net Income (GAAP) <sup>(1)</sup>	\$85	\$114	\$210	\$1,281	\$1,690
Operating Exclusions	(\$23)	(\$12)	(\$25)	\$34	(\$25)
Adjusted Operating Earnings <sup>(1)</sup>	\$63	\$103	\$185	\$1,315	\$1,665
Average Equity	\$1,061	\$1,323	\$2,419	\$12,750	\$17,554
<b>Operating ROE (Adjusted Operating Earnings/Average Equity)</b>	<b>5.9%</b>	<b>7.8%</b>	<b>7.7%</b>	<b>10.3%</b>	<b>9.5%</b>

Q2 2017 Operating ROE Reconciliation (\$M) <sup>(1)</sup>	ACE	Delmarva	Pepco	Legacy EXC	Consolidated EU
Net Income (GAAP) <sup>(1)</sup>	\$91	\$127	\$203	\$1,132	\$1,548
Operating Exclusions	(\$25)	(\$32)	(\$29)	\$186	\$105
Adjusted Operating Earnings <sup>(1)</sup>	\$66	\$95	\$174	\$1,318	\$1,653
Average Equity	\$1,039	\$1,300	\$2,390	\$12,308	\$17,038
<b>Operating ROE (Adjusted Operating Earnings/Average Equity)</b>	<b>6.4%</b>	<b>7.3%</b>	<b>7.3%</b>	<b>10.7%</b>	<b>9.7%</b>

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

# GAAP to Non-GAAP Reconciliations

2017 Adjusted Cash from Ops Calculation (\$M) <sup>(1)</sup>	ComEd	PECO	BGE	PHI	ExGen	Other	Exelon
Net cash flows provided by operating activities (GAAP)	\$1,375	\$750	\$775	\$1,175	\$3,400	(\$250)	\$7,225
Other cash from investing activities	-	-	-	-	(\$275)	-	(\$275)
Intercompany receivable adjustment	(\$350)	-	-	-	-	\$350	-
Counterparty collateral activity	-	-	-	-	\$200	-	\$200
<b>Adjusted Cash Flow from Operations</b>	<b>\$1,025</b>	<b>\$750</b>	<b>\$775</b>	<b>\$1,175</b>	<b>\$3,350</b>	<b>\$75</b>	<b>\$7,150</b>

2017 Cash From Financing Calculation (\$M) <sup>(1)</sup>	ComEd	PECO	BGE	PHI	ExGen	Other	Exelon
Net cash flow provided by financing activities (GAAP)	\$825	\$175	\$150	\$125	(\$300)	\$400	\$1,375
Dividends paid on common stock	\$425	\$300	\$200	\$325	\$650	(\$675)	\$1,225
Intercompany receivable adjustment	\$350	-	-	-	-	(\$350)	-
<b>Financing Cash Flow</b>	<b>\$1,600</b>	<b>\$475</b>	<b>\$350</b>	<b>\$450</b>	<b>\$350</b>	<b>(\$625)</b>	<b>\$2,625</b>

Exelon Total Cash Flow Reconciliation <sup>(1)</sup>	2017
<b>GAAP Beginning Cash Balance</b>	<b>\$650</b>
Adjustment for Cash Collateral Posted	<u>\$400</u>
Adjusted Beginning Cash Balance <sup>(3)</sup>	\$1,050
Net Change in Cash (GAAP) <sup>(2)</sup>	<u>\$400</u>
Adjusted Ending Cash Balance <sup>(3)</sup>	\$1,450
Adjustment for Cash Collateral Posted	<u>(\$625)</u>
<b>GAAP Ending Cash Balance</b>	<b>\$825</b>

(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) <sup>(1)</sup>	2017	2018	2019	2020
<b>GAAP O&amp;M</b>	<b>\$6,325</b>	<b>\$5,300</b>	<b>\$5,150</b>	<b>\$5,025</b>
Decommissioning <sup>(2)</sup>	25	50	50	50
TMI Retirement	(75)	-	-	-
EGTP Impairment	(450)	-	-	-
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses <sup>(3)</sup>	(425)	(325)	(325)	(325)
O&M for managed plants that are partially owned	(425)	(425)	(400)	(425)
Other	(125)	(25)	(25)	(25)
<b>Adjusted O&amp;M (Non-GAAP)</b>	<b>\$4,850</b>	<b>\$4,600</b>	<b>\$4,450</b>	<b>\$4,300</b>

2017-2020 ExGen Free Cash Flow Calculation (\$M) <sup>(1)</sup>	
Cash from Operations (GAAP)	\$15,150
Other Cash from Investing and Activities	(\$650)
Baseline Capital Expenditures <sup>(4)</sup>	(\$4,025)
Nuclear Fuel Capital Expenditures	(\$3,625)
<b>Free Cash Flow before Growth CapEx and Dividend</b>	<b>\$6,825</b>

(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