

# Earnings Conference Call

## 1<sup>st</sup> Quarter 2017

May 3, 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 First Quarter 2017 Quarterly Report on Form 10-Q (to be filed on May 3, 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 17; 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

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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 businesses, decommissioning costs that do not affect profit and loss, the impact from operating and maintenance expense related to variable interest entities at Generation, 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** or **free cash flow** 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
- **Operating ROE** is calculated using operating net income divided by simple 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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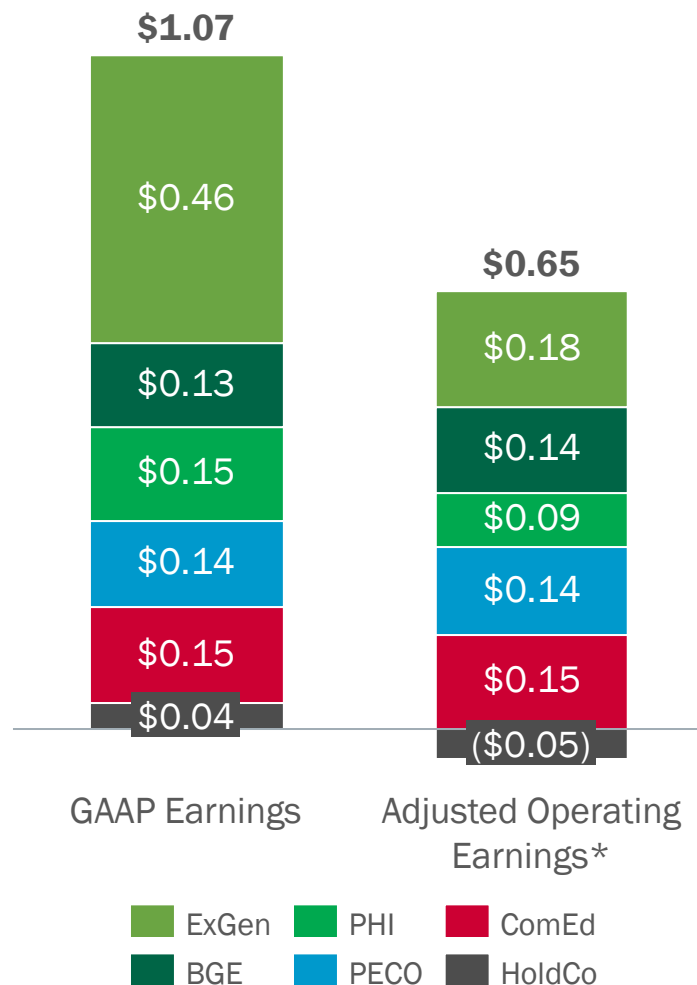
This information is intended to enhance an investor's overall understanding of period over period financial results and provide an indication of Exelon's baseline operating performance by excluding items that are considered by management to be not directly related to the ongoing operations of the business. 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 measure 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 27 of this presentation.

# Strong 1<sup>st</sup> Quarter Results

## Q1 2017 EPS Results



- GAAP earnings were \$1.07/share in Q1 2017 vs. \$0.19/share in Q1 2016
- Adjusted operating earnings\* were \$0.65/share in Q1 2017 vs. \$0.68/share in Q1 2016, at the top of our guidance range of \$0.55-\$0.65/share

Note: Amounts may not sum due to rounding

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

# Best in Class Operations

Exelon Utilities Operational Metrics					
Operations	Metric	Q1 2017			
		BGE	PECO	ComEd	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	

- PHI Service Level represents best on record
- PECO Customer Satisfaction on track for best year ever
- BGE is experiencing their best ever CAIDI and SAIFI performance

(1) 2.5 Beta SAIFI is YE projection

(2) 2016 industry average

Q1	Q2
Q3	Q4

## Exelon Generation Operational Metrics

- Continued best in class performance across our Nuclear fleet:
  - Q1 Nuclear Capacity Factor: 94.0%
  - Q1 average refueling outage duration of 26 days versus industry average of 36 days<sup>(2)</sup>
  - Shortest refueling outage duration record set for Calvert Cliffs 2
- Strong performance across our Fossil and Renewable fleet:
  - Renewables energy capture: 95.7%
  - Power dispatch match: 99.1%

# Update on Key Ongoing Items

## New York ZEC Legal Challenges

- Hearings on motion to dismiss held on March 29
- Currently awaiting decision; no defined timeline
- Outcome on motion to dismiss will determine next steps
- ZEC program went effective on April 1, 2017

## IL ZEC Legal Challenges

- Plaintiffs filed for a preliminary injunction on March 31
- Motion to dismiss filed April 10
- Preliminary injunction held by judge while he receives full briefing on motion to dismiss
- Plaintiffs filed their responses on April 24 and defendant replies are due on or before May 15
- Judge will inform parties of his intentions on May 22
- The Illinois law becomes effective on June 1, 2017

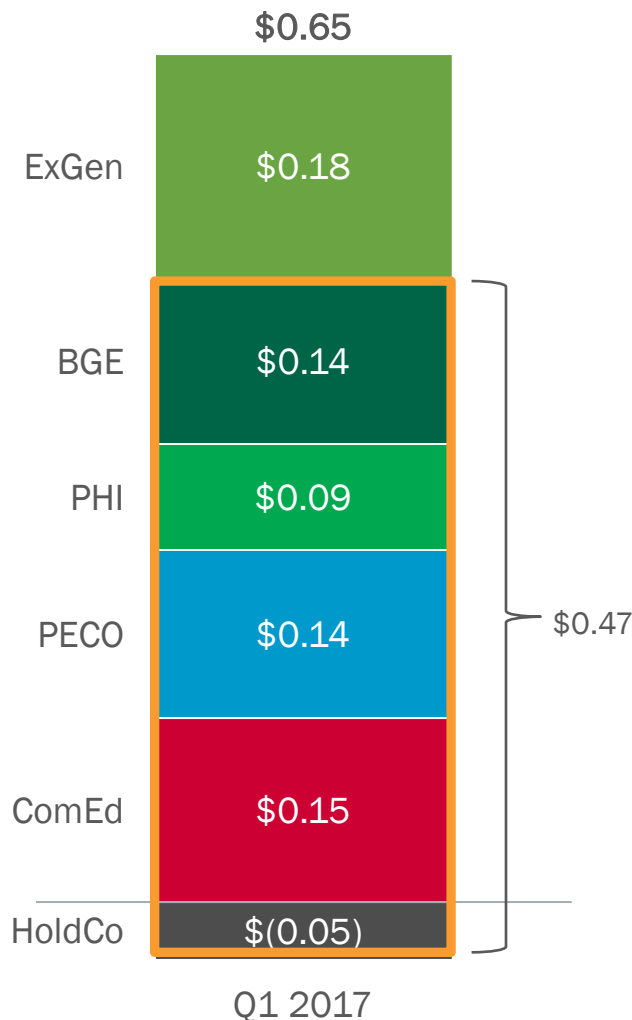
## Capacity Market Update

- Transition to 100% Capacity Performance could lead to more responsible bidding
- Tightening of CETL numbers for ComEd and EMAAC LDAs could signal a more constrained market
- Lower PJM demand forecast and higher new build risk are potential headwinds to clearing prices

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# 1<sup>st</sup> Quarter Adjusted Operating Earnings\* Drivers

## Q1 2017 Adjusted Operating EPS\* Results



## Q1 2017 vs. Guidance of \$0.55 - \$0.65

### Exelon Utilities

- ↑ Timing of O&M
- ↓ Unfavorable weather

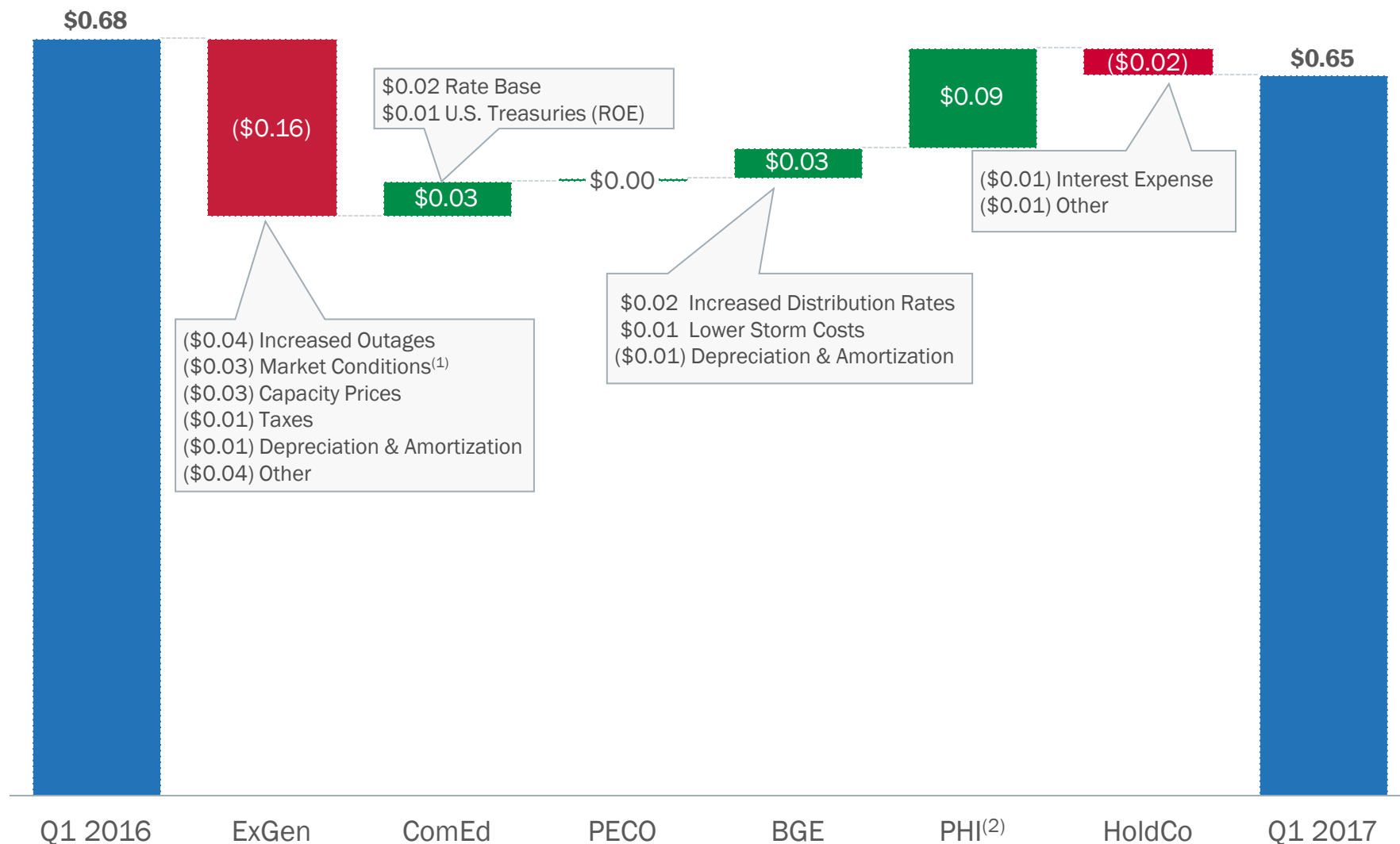
### Exelon Generation

- ↑ Generation performance
- ↑ Timing of O&M

Note: Amounts may not sum due to rounding



# Q1 Adjusted Operating Earnings\* Waterfall

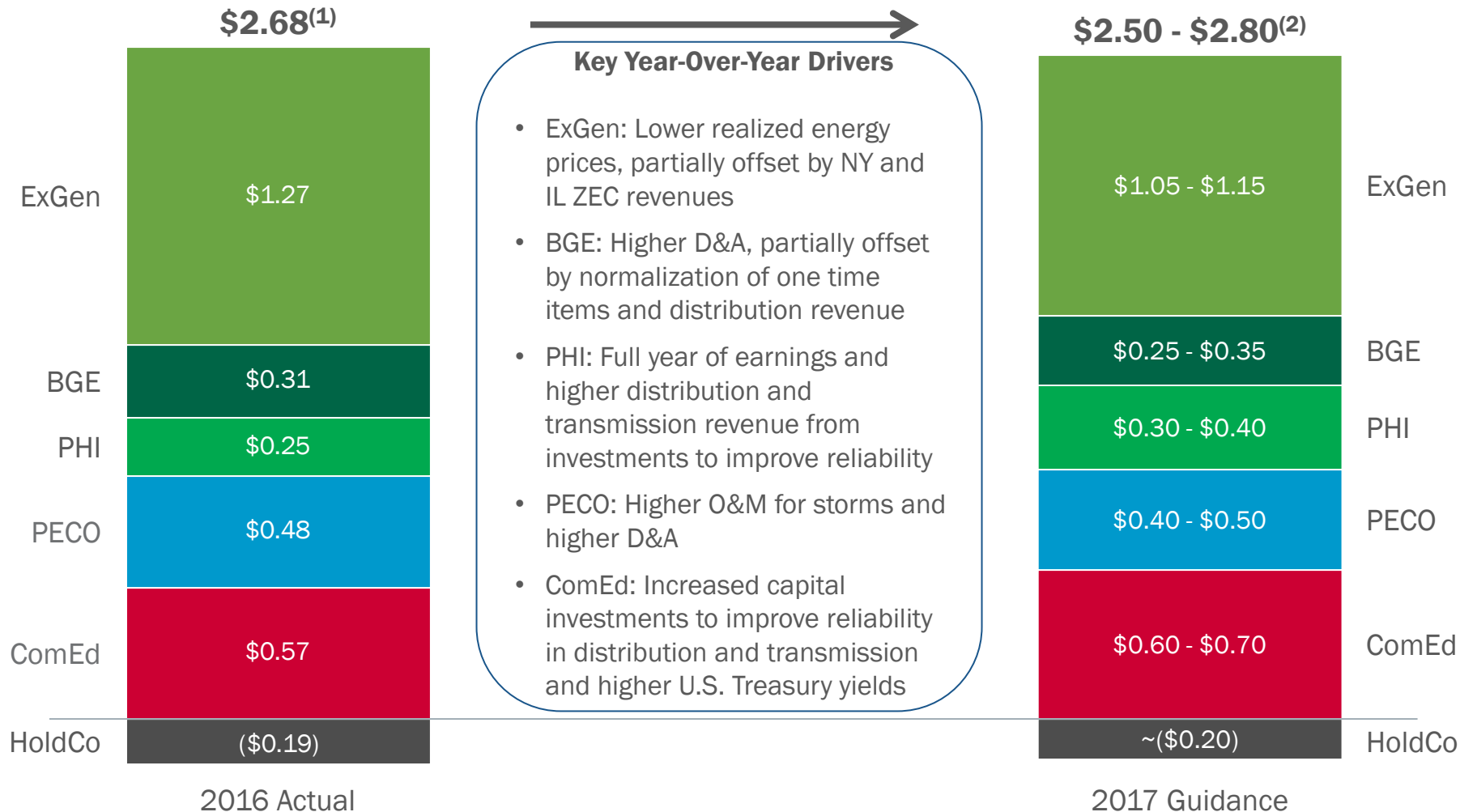


Note: Amounts may not sum due to rounding

(1) Includes the unfavorable impact of declining natural gas prices on Generation's natural gas portfolio and lower realized energy prices as well as the favorable impact of the Ginna Reliability Support Services Agreement in 2017

(2) PHI reflects full quarter of earnings in 2017 versus 8 days of earnings from March 23, 2016 through March 31, 2016

# Reaffirming 2017 Adjusted Operating Earnings\* Guidance



**Expect Q2 2017 Adjusted Operating Earnings\* of \$0.45 - \$0.55 per share**

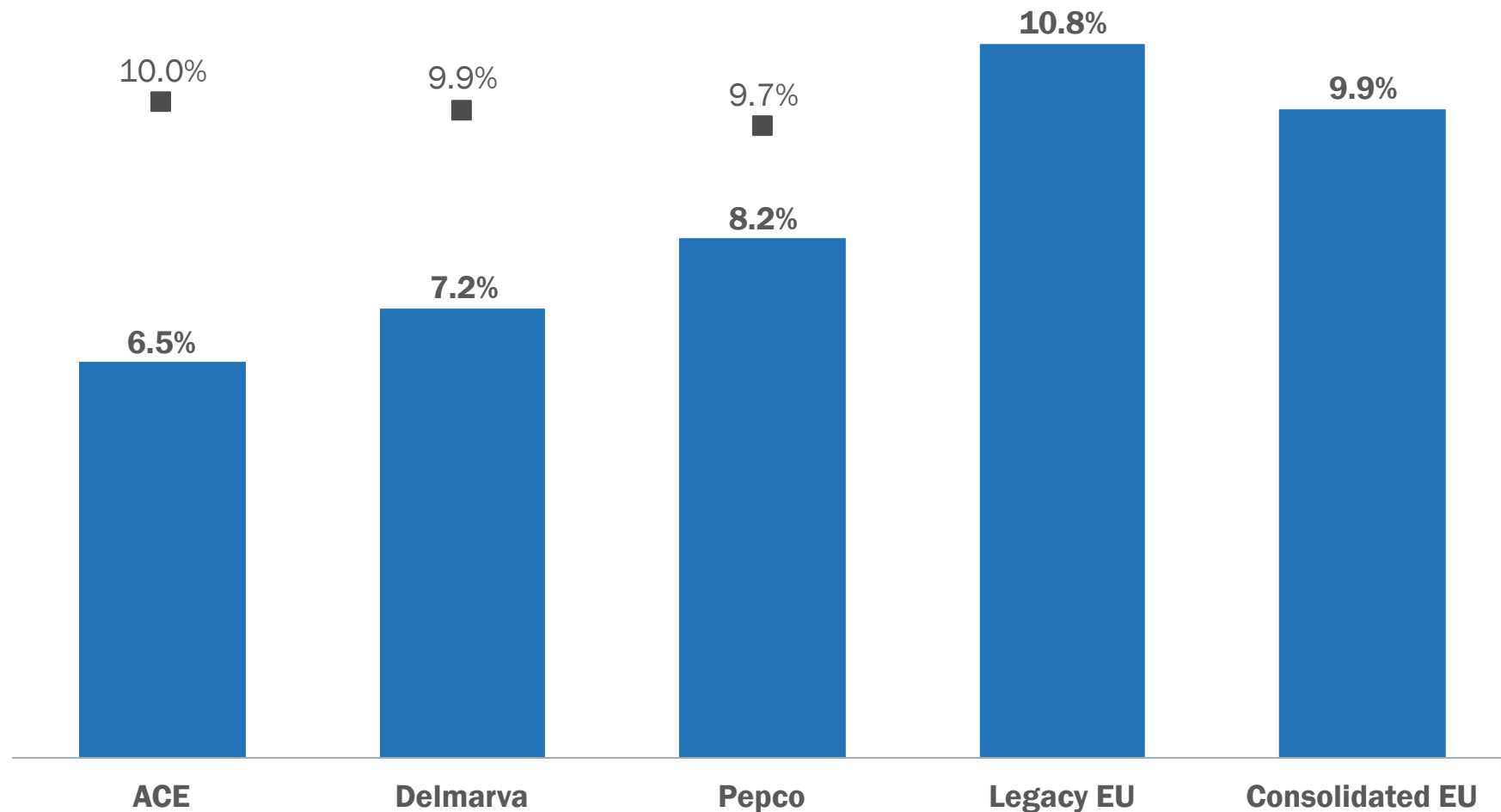
(1) 2016 results based on 2016 average outstanding shares of 927M

(2) 2017 earnings guidance based on expected average outstanding shares of 949M. Earnings guidance for OpCos may not sum up to consolidated EPS guidance.

# Trailing 12 Month ROE vs Allowed ROE

## Twelve Month Trailing Earned ROEs\*

■ Allowed ROE ■ Earned ROE



Note: Represents the period from 3/31/16 to 3/31/17 and reflects all lines of business (Electric Distribution, Gas Distribution, and Transmission)

# Exelon Utilities Distribution Rate Case Summary

Delmarva MD Order		Pepco MD Filing	
Authorized Revenue Requirement Increase <sup>(1)</sup>	\$38.3M	Requested Revenue Requirement Increase <sup>(1)</sup>	\$68.6M
Authorized ROE	9.60%	Requested ROE	10.10%
Common Equity Ratio	49.10%	Requested Common Equity Ratio	50.15%
Order Received	2/15/17	Order Expected	Q4 2017
Delmarva DE Electric Filing		ACE Filing	
Revenue Requirement Increase (per pending settlement) <sup>(1)</sup>	\$31.5M	Requested Revenue Requirement Increase <sup>(1)</sup>	\$70.2M
ROE (per pending settlement)	9.70%	Requested ROE	10.10%
Common Equity Ratio	49.44%	Requested Common Equity Ratio	50.14%
Order Expected	Q2 2017	Order Expected	Q1 2018
Delmarva DE Gas Filing		ComEd Filing	
Revenue Requirement Increase (per pending settlement) <sup>(1)</sup>	\$4.9M	Requested Revenue Requirement Increase <sup>(1)</sup>	\$96.3M
ROE (per pending settlement)	9.70%	Requested ROE	8.40%
Common Equity Ratio	49.44%	Requested Common Equity Ratio	45.89%
Order Expected	Q2 2017	Order Expected	Q4 2017
Pepco DC Filing			
Requested Revenue Requirement Increase <sup>(1)</sup>	\$76.8M		
Requested ROE	10.60%		
Requested Common Equity Ratio	49.14%		
Order Expected	7/25/17		

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

# Exelon Generation: Gross Margin Update

	March 31, 2017			Change from Dec 31, 2016		
Gross Margin Category (\$M) <sup>(1)</sup>	2017	2018	2019	2017	2018	2019
Open Gross Margin <sup>(2)</sup> (including South, West, Canada hedged gross margin)	\$3,850	\$4,150	\$3,950	\$(250)	\$(50)	\$(100)
Capacity and ZEC Revenues <sup>(2)</sup>	\$1,850	\$2,250	\$2,050	-	-	-
Mark-to-Market of Hedges <sup>(2,3)</sup>	\$1,600	\$500	\$400	\$400	\$50	\$50
Power New Business / To Go	\$400	\$850	\$950	\$(150)	\$(50)	-
Non-Power Margins Executed	\$250	\$150	\$100	\$50	\$50	\$50
Non-Power New Business / To Go	\$200	\$350	\$400	\$(50)	\$(50)	\$(50)
<b>Total Gross Margin<sup>*(4,5)</sup></b>	<b>\$8,150</b>	<b>\$8,250</b>	<b>\$7,850</b>	<b>-</b>	<b>\$(50)</b>	<b>\$(50)</b>

## Recent Developments

- Executed \$150M and \$50M of Power New Business in 2017 and 2018, respectively
- Behind ratable hedging position reflects the fundamental upside we see in power prices
  - ~12-15% behind ratable in 2018

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 March 31, 2017, market conditions  
 5) Reflects Oyster Creek retirement in December 2019

# Summary of Recent Key Transactions



## Exelon Generation Renewables JV

- \$400M of pre-tax proceeds from Hancock, representing an EV/EBITDA multiple greater than 10x
- 1,296 MW of renewable generation capacity
- Option to drop additional projects into the JV
- Proceeds will be used to accelerate debt reduction strategy



## FitzPatrick Nuclear Station

- Acquisition completed on March 31, 2017
- Adds 838 MW of nuclear capacity to the portfolio
- Part of NY ZEC Program and started realizing benefit of ZEC payments on April 1, 2017



## ExGen Texas Power

- 3,476 MW ERCOT conventional power portfolio consisting of CCGTs and Simple Cycles
- Plants economically challenged due to downturn in ERCOT power prices
- Reached agreement with lenders to pursue a potential sale of the assets



## Mystic 8 & 9

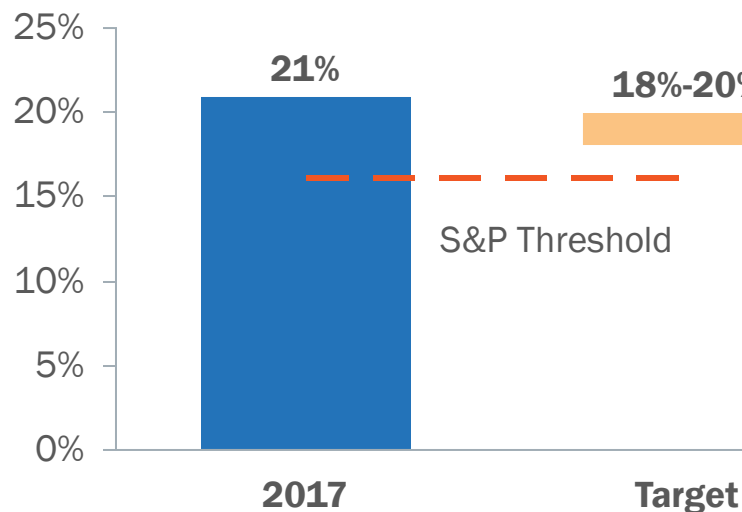
- No longer pursuing sale of assets
- No impact to our commitments on Debt/EBITDA and debt reduction

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

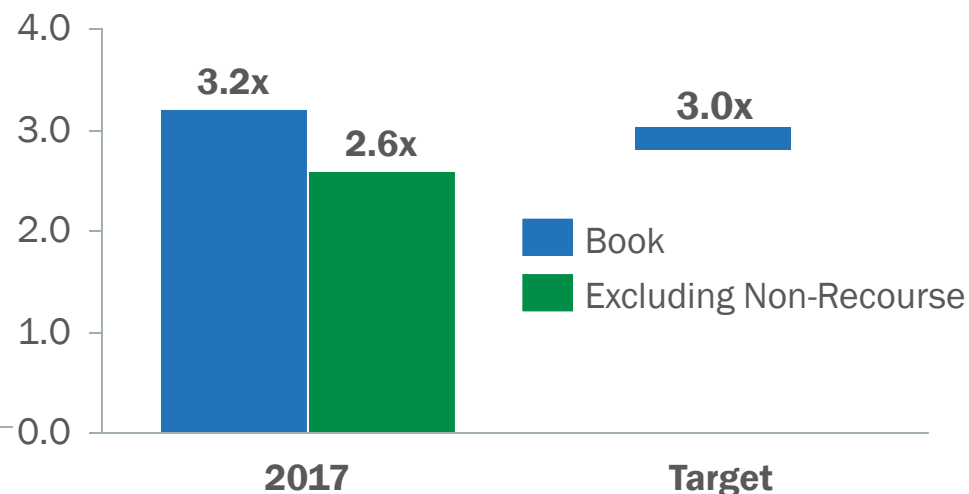
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## Exelon S&P FFO/Debt %<sup>\*(1,4)</sup>



## ExGen Debt/EBITDA Ratio<sup>\*(5)</sup>



## 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	A2	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 March 31, 2017, for Exelon, Exelon Generation and BGE and senior secured ratings for ComEd, PECO, ACE, DPL, and Pepco

(3) Moody's has ComEd on "Positive" outlook. All other ratings have "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\*

# 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>(9)</sup>	Exelon 2017E	Cash Balance
<b>Beginning Cash Balance</b> * <sup>(2)</sup>									<b>1,050</b>
Adjusted Cash Flow from Operations* <sup>(3)</sup>	725	725	725	1,225	3,425	3,525	125	7,075	
Base CapEx and Nuclear Fuel <sup>(4)</sup>	0	0	0	0	0	(2,050)	(50)	(2,125)	
<b>Free Cash Flow*</b>	<b>725</b>	<b>725</b>	<b>725</b>	<b>1,225</b>	<b>3,425</b>	<b>1,475</b>	<b>50</b>	<b>4,950</b>	
Debt Issuances	0	1,000	325	200	1,525	750	1,150	3,425	
Debt Retirements	(50)	(425)	0	(150)	(625)	(700)	(1,700)	(3,025)	
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	150	650	0	775	1,575	0	(1,575)	0	
Other Financing <sup>(5)</sup>	275	625	150	(375)	650	350	375	1,375	
<b>Financing</b> * <sup>(6)</sup>	<b>375</b>	<b>1,850</b>	<b>475</b>	<b>450</b>	<b>3,150</b>	<b>675</b>	<b>(625)</b>	<b>3,200</b>	
<b>Total Free Cash Flow and Financing</b>	<b>1,125</b>	<b>2,575</b>	<b>1,200</b>	<b>1,650</b>	<b>6,550</b>	<b>2,150</b>	<b>(550)</b>	<b>8,150</b>	
Utility Investment	(925)	(2,200)	(775)	(1,375)	(5,250)	0	0	(5,250)	
ExGen Growth <sup>(4,7)</sup>	0	0	0	0	0	(850)	0	(850)	
Acquisitions and Divestitures	0	0	0	0	0	0	0	0	
Equity Investments	0	0	0	0	0	(50)	0	(50)	
Dividend <sup>(8)</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>(925)</b>	<b>(1,225)</b>	<b>(7,425)</b>	
<b>Total Cash Flow</b>	<b>200</b>	<b>400</b>	<b>450</b>	<b>275</b>	<b>1,300</b>	<b>1,225</b>	<b>(1,800)</b>	<b>725</b>	
<b>Ending Cash Balance</b> * <sup>(2)</sup>									<b>1,775</b>

- (1) All amounts rounded to the nearest \$25M. Figures may not sum due to rounding.
- (2) Gross of posted counterparty collateral
- (3) Excludes counterparty collateral activity
- (4) Figures reflect cash CapEx and CENG fleet at 100%
- (5) Other Financing includes 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, proceeds from ExGen Renewables JV, and CENG tax distributions to EDF
- (6) Financing cash flow excludes intercompany dividends and other intercompany financing activities
- (7) ExGen Growth CapEx primarily includes Texas CCGTs, West Medway, AGE, Nuclear Upgrades, and Retail Solar
- (8) Dividends are subject to declaration by the Board of Directors
- (9) 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 \$5.0B of free cash flow\* before growth, including \$1.5B at ExGen and \$3.4B at the Utilities

## Supported by a strong balance sheet

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

- ✓ Plan to issue \$1.5B of long-term debt at the utilities to support continued growth
- ✓ Retiring \$700M debt to begin strategy of de-levering ExGen

## Enable growth & value creation

*Creating value for customers, communities and shareholders*

- ✓ Investing \$6.1B, with \$5.3B at the Utilities and \$0.9B at ExGen

# **Exelon Generation Disclosures**

**March 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

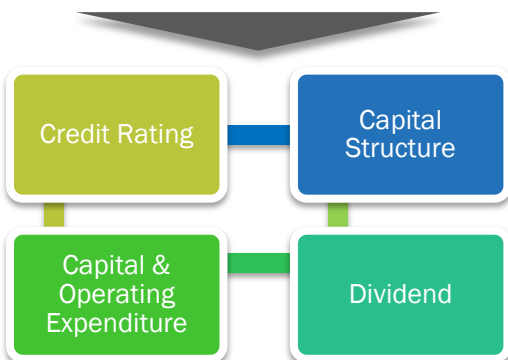
- Ensure stability in near-term cash flows and earnings
- Disciplined approach to hedging
- Tenor aligns with customer preferences and market liquidity
- Multiple channels to market that allow us to maximize margins
- Large open position in outer years to benefit from price upside

## Bull / Bear Program

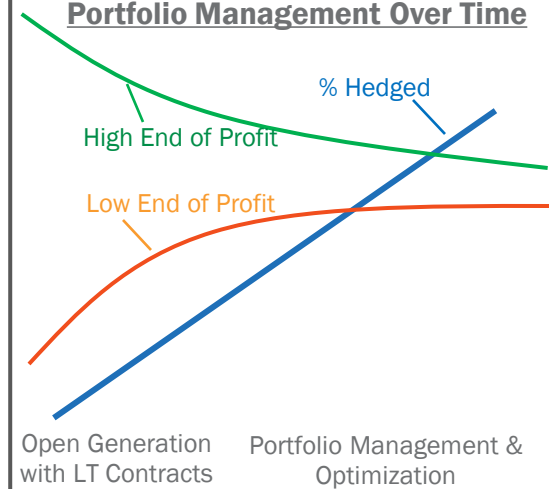
- Ability to exercise fundamental market views to create value within the ratable framework
- Modified timing of hedges versus purely ratable
- Cross-commodity hedging (heat rate positions, options, etc.)
- Delivery locations, regional and zonal spread relationships

## Align Hedging & Financials

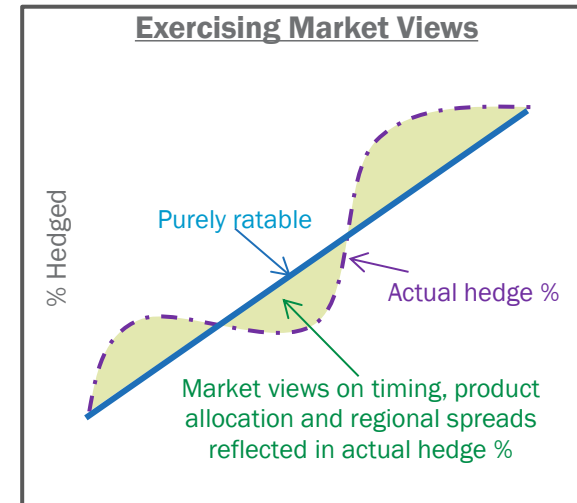
### Establishing Minimum Hedge Targets



## 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<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)</sup>	\$3,850	\$4,150	\$3,950
Capacity and ZEC Revenues <sup>(2)</sup>	\$1,850	\$2,250	\$2,050
Mark-to-Market of Hedges <sup>(2,3)</sup>	\$1,600	\$500	\$400
Power New Business / To Go	\$400	\$850	\$950
Non-Power Margins Executed	\$250	\$150	\$100
Non-Power New Business / To Go	\$200	\$350	\$400
<b>Total Gross Margin*<sup>(5)</sup></b>	<b>\$8,150</b>	<b>\$8,250</b>	<b>\$7,850</b>

Reference Prices <sup>(4)</sup>	2017	2018	2019
Henry Hub Natural Gas (\$/MMbtu)	\$3.31	\$3.03	\$2.83
Midwest: NiHub ATC prices (\$/MWh)	\$27.72	\$27.82	\$26.39
Mid-Atlantic: PJM-W ATC prices (\$/MWh)	\$31.10	\$32.07	\$30.21
ERCOT-N ATC Spark Spread (\$/MWh) <i>HSC Gas, 7.2HR, \$2.50 VOM</i>	\$0.66	\$1.66	\$1.95
New York: NY Zone A (\$/MWh)	\$27.15	\$29.40	\$28.38
New England: Mass Hub ATC Spark Spread (\$/MWh) <i>ALQN Gas, 7.5HR, \$0.50 VOM</i>	\$4.91	\$5.12	\$6.01

- 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 March 31, 2017, market conditions
- 5) Reflects ownership of FitzPatrick as of April 1, 2017, and Oyster Creek retirement in December 2019

# ExGen Disclosures

Generation and Hedges	2017	2018	2019
<u>Exp. Gen (GWh)<sup>(1)</sup></u>	<b>203,400</b>	<b>208,700</b>	<b>212,200</b>
Midwest	95,700	96,000	97,000
Mid-Atlantic <sup>(2,6)</sup>	60,300	60,400	60,100
ERCOT	21,000	28,500	29,500
New York <sup>(2)</sup>	14,600	15,400	16,600
New England	11,800	8,400	9,000
<u>% of Expected Generation Hedged<sup>(3)</sup></u>	<b>97%-100%</b>	<b>60%-63%</b>	<b>30%-33%</b>
Midwest	94%-97%	55%-58%	27%-30%
Mid-Atlantic <sup>(2,6)</sup>	105%-108%	71%-74%	35%-38%
ERCOT	91%-94%	62%-65%	26%-29%
New York <sup>(2)</sup>	91%-94%	46%-49%	35%-38%
New England	99%-102%	68%-71%	36%-39%
<u>Effective Realized Energy Price (\$/MWh)<sup>(4)</sup></u>			
Midwest	\$32.00	\$30.00	\$29.50
Mid-Atlantic <sup>(2,6)</sup>	\$42.50	\$38.00	\$41.00
ERCOT <sup>(5)</sup>	\$8.00	\$4.50	\$3.00
New York <sup>(2)</sup>	\$40.50	\$39.00	\$30.50
New England <sup>(5)</sup>	\$18.50	\$4.50	\$4.00

(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 12 in 2019 at Exelon-operated nuclear plants and Salem. Expected generation assumes capacity factors of 93.4%, 93.3% and 94.5% 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 Oyster Creek retirement in December 2019

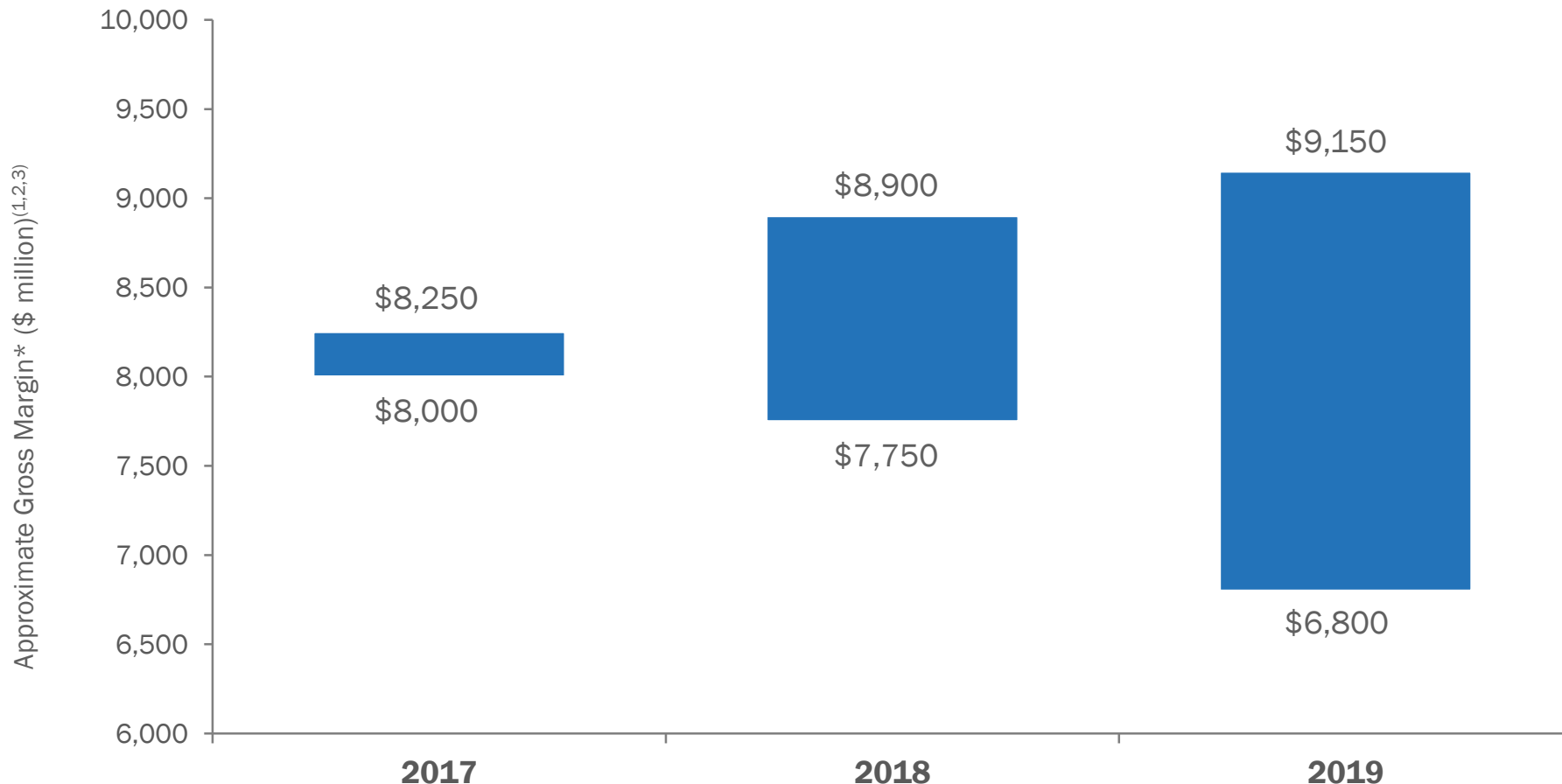
# ExGen Hedged Gross Margin\* Sensitivities

Gross Margin Sensitivities (with Existing Hedges) <sup>(1)</sup>	2017	2018	2019
Henry Hub Natural Gas (\$/Mmbtu)			
+ \$1/Mmbtu	\$15	\$285	\$520
- \$1/Mmbtu	\$60	\$(270)	\$(490)
NiHub ATC Energy Price			
+ \$5/MWh	\$10	\$200	\$335
- \$5/MWh	\$(10)	\$(200)	\$(330)
PJM-W ATC Energy Price			
+ \$5/MWh	\$(15)	\$85	\$195
- \$5/MWh	\$25	\$(95)	\$(185)
NYPP Zone A ATC Energy Price			
+ \$5/MWh	\$10	\$45	\$50
- \$5/MWh	\$(5)	\$(40)	\$(55)
Nuclear Capacity Factor			
+/- 1%	+/- \$30	+/- \$40	+/- \$35

(1) Based on March 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 prices 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 March 31, 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 Oyster Creek retirement in December 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	← \$4.15 billion →					
(B)	Capacity and ZEC	← \$2.25 billion →					
(C)	Expected Generation (TWh)	96.0	60.4	28.5	15.4	8.4	
(D)	Hedge % (assuming mid-point of range)	56.5%	72.5%	63.5%	47.5%	69.5%	
(E=C*D)	Hedged Volume (TWh)	54.2	43.8	18.1	7.3	5.8	
(F)	Effective Realized Energy Price (\$/MWh)	\$30.00	\$38.00	\$4.50	\$39.00	\$4.50	
(G)	Reference Price (\$/MWh)	\$27.82	\$32.07	\$1.66	\$29.40	\$5.12	
(H=F-G)	Difference (\$/MWh)	\$2.18	\$5.93	\$2.84	\$9.60	(\$0.62)	
(I=E*H)	Mark-to-Market value of hedges (\$ million) <sup>(1)</sup>	\$120	\$260	\$50	\$70	(\$5)	
(J=A+B+I)	Hedged Gross Margin (\$ million)	\$6,900					
(K)	Power New Business / To Go (\$ million)	\$850					
(L)	Non-Power Margins Executed (\$ million)	\$150					
(M)	Non-Power New Business / To Go (\$ million)	\$350					
(N=J+K+L+M)	Total Gross Margin *	\$8,250 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>\$8,725</b>	<b>\$8,875</b>	<b>\$8,450</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>	\$(200)	\$(225)	\$(200)
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses <sup>(5)</sup>	\$(425)	\$(400)	\$(400)
<b>Total Gross Margin* (Non-GAAP)</b>	<b>\$8,150</b>	<b>\$8,250</b>	<b>\$7,850</b>

Key ExGen Modeling Inputs (in \$M) <sup>(1,6)</sup>	2017
Other <sup>(7)</sup>	\$175
Adjusted O&M*	\$(4,850)
Taxes Other Than Income (TOTI) <sup>(8)</sup>	\$(375)
Depreciation & Amortization <sup>(9)</sup>	\$(1,125)
Interest Expense <sup>(10)</sup>	\$(425)
<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 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) Reflects the cost of sales of certain Constellation and Power businesses

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

(7) 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

(8) TOTI excludes gross receipts tax of \$100M

(9) Excludes P&L neutral decommissioning depreciation

(10) Interest expense includes impact of reduced capitalized interest due to Texas CCGT plants going into service in 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

	3/17	4/17	5/17	6/17	7/17	8/17	9/17
<b>ComEd Electric Distribution Formula Rate</b>		2017 FRU Filing April 13			Rebuttal Testimony Mid-July		
<b>Pepco Electric Distribution Rates - DC</b>	Evidentiary Hearings Mar 15-21	Final Reply Briefs April 24			Commission Order Expected July 25		
<b>Delmarva Electric Distribution Rates - DE</b>	Settlement Filed Mar 8						
<b>Delmarva Gas Distribution Rates - DE</b>		Settlement Filed April 6					
<b>Pepco Electric Distribution Rates - MD</b>	Rate Case Filed Mar 24			Intervenor Direct Testimony June 30		Rebuttal Testimony Aug 1	Evidentiary Hearings Sep 5-15
<b>ACE Electric Distribution Rates - NJ</b>	Rate Case Filed Mar 30						

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

# ComEd April 2017 Distribution Formula Rate

The 2017 distribution formula rate filing established the net revenue requirement used to set the rates that took 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</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</b>	<b>\$96M increase</b> (\$18M increase due to the 2016 reconciliation and collar adjustment in addition to a \$78M 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> </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.**

# Atlantic City Electric NJ Rate Case Filing

<b>BPU Docket No.</b>	ER17030308
<b>Test Year</b>	August 1, 2016 – July 31, 2017
<b>Test Period</b>	5 months actual and 7 months estimated
<b>Requested Common Equity Ratio</b>	50.14%
<b>Requested Rate of Return</b>	ROE: 10.10%; ROR: 7.83%
<b>Proposed Rate Base (Adjusted)</b>	\$1.37B
<b>Requested Revenue Requirement Increase<sup>(1)</sup></b>	\$70.2M
<b>Residential Total Bill % Increase</b>	6.57%
<b>Notes</b>	<ul style="list-style-type: none"> <li>• 3/30/17 ACE filed application with the New Jersey Board of Public Utilities (NJBPUB) seeking increase in electric distribution base rates</li> <li>• Recovery of investment in infrastructure to maintain and harden the electric distribution system</li> <li>• Ratemaking adjustments to address declining sales</li> <li>• 8 month forward-looking reliability and other plant additions from August 2017 through March 2018 (\$8.4M of Revenue Requirement based on 10.10% ROE) included in revenue requirement request</li> <li>• Proposal of a Non-Incremental System Renewal Recovery Charge for recovery of non-incremental reliability spend over four years (2018-2021) of \$376 million</li> </ul>

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

# Pepco MD Rate Case Filing

<b>Formal Case No.</b>	9443
<b>Test Year</b>	May 1, 2016 – April 30, 2017
<b>Test Period</b>	8 months actual and 4 months estimated
<b>Requested Common Equity Ratio</b>	50.15%
<b>Requested Rate of Return</b>	ROE: 10.10%; ROR: 7.79%
<b>Proposed Rate Base (Adjusted)</b>	\$1.71B
<b>Requested Revenue Requirement Increase<sup>(1)</sup></b>	\$68.6M
<b>Residential Total Bill % Increase</b>	5.52%
<b>Notes</b>	<ul style="list-style-type: none"> <li>• 3/24/17 Pepco MD filed application with the Maryland Public Service Commission (MDPSC ) seeking increase in electric distribution base rates</li> <li>• Size of ask is driven by Continued Investments in the electric distribution system to maintain and increase reliability and customer service</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> <li>• Company is seeking recovery of the restoration portion of the Supplemental Executive Retirement Plan (SERP)</li> </ul> <p>Procedural Schedule:</p> <ul style="list-style-type: none"> <li>• Intervenor Direct Testimony Due: 6/30/17</li> <li>• Rebuttal Testimony Due: 8/1/17</li> <li>• Evidentiary Hearings: 9/5/17 – 9/15/17</li> <li>• Brief Due: 10/3/17</li> <li>• Commission Order Expected: 10/20/17</li> </ul>

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



# Delmarva DE (Electric) Distribution Rate Case

<b>Docket #</b>	16-0649	<b>Black Box Settlement Terms</b>
<b>Test Year</b>	2015 Calendar Year	
<b>Test Period</b>	12 months actual	
<b>Common Equity Ratio</b>	49.44%	
<b>Rate of Return</b>	ROE: 10.60%; ROR: 7.19%	ROE: 9.70%
<b>Rate Base</b>	\$839M	
<b>Revenue Requirement Increase (Updated on March 8, 2017)<sup>(1,2)</sup></b>	\$60.2M	\$31.5M Revenue increase includes approx. \$7.5M of new depreciation and amortization expense
<b>Residential Total Bill % Increase</b>	7.25%	TBD
<b>Notes</b>	<ul style="list-style-type: none"> <li>• 5/17/16 DPL DE filed application with the Delaware Public Service Commission (DPSC) seeking increase in electric distribution base rates</li> <li>• 18 month forward-looking reliability and other plant additions from January 2016 through June 2017 (\$8.4M of Revenue Requirement based on 10.60% ROE) included in revenue requirement request</li> <li>• Includes the Pay as You Go Program, a proposed pilot program that would be cooperatively designed to use the capability of the AMI meters to offer a voluntary pre-paid metering option for customers</li> </ul>	<ul style="list-style-type: none"> <li>• 3/8/17 Unanimous settlement filed with the DPSC</li> <li>• New depreciation rates included in the revenue increase</li> <li>• Recovery of \$28.6M of direct load control and dynamic pricing regulatory assets to be amortized over 10 years</li> <li>• Approval to establish regulatory asset for costs to achieve synergy savings, amortized over 5 years</li> <li>• Actual synergy savings and costs to achieve will be reviewed in next base rate proceeding</li> <li>• Rates will go into effect 30 days after DPSC approval</li> </ul>

(1) As permitted by Delaware law, Delmarva Power implemented interim rate increases of \$2.5 million on July 16, 2016, and implemented an incremental \$29.6M on December 17, 2016, subject to refund

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

# Delmarva DE (Gas) Distribution Rate Case

<b>Docket #</b>	16-0650	<b>Black Box Settlement Terms</b>
<b>Test Year</b>	2015 Calendar Year	
<b>Test Period</b>	12 months actual	
<b>Common Equity Ratio</b>	49.44%	
<b>Rate of Return</b>	ROE: 10.60%; ROR: 7.19%	ROE: 9.70%
<b>Rate Base</b>	\$362M	
<b>Revenue Requirement Increase<sup>(1,2)</sup></b>	\$22.2M	\$4.9M Revenue increase includes net reduction of \$4.8M in new depreciation and amortization expense
<b>Residential Total Bill % Increase</b>	10.40%	TBD
<b>Notes</b>	<ul style="list-style-type: none"> <li>• 5/17/16 DPL DE filed application with the DPSC seeking increase in gas distribution base rates</li> <li>Intervenor Positions: <ul style="list-style-type: none"> <li>• Staff revenue decrease of \$3.1M based on 9.20% ROE</li> <li>• Division of the Public Advocate (DPA) revenue decrease of \$2.1M based on 9.00% ROE</li> </ul> </li> </ul>	
		<ul style="list-style-type: none"> <li>• 4/6/17 Unanimous settlement filed with the DPSC</li> <li>• New depreciation rates included in the revenue increase</li> <li>• Incremental labor costs for the Interface Management Unit (IMU) battery replacement project deferred into a regulatory asset for review in a future proceeding</li> <li>• Approval to establish regulatory asset for costs to achieve synergy savings, amortized over 5 years</li> <li>• Projected synergy savings and costs to achieve will be reviewed against actuals in next base rate proceeding</li> <li>• Rates will go into effect 30 days after DPSC approval</li> </ul>

(1) As permitted by Delaware law, Delmarva Power implemented interim rate increases of \$2.5 million on July 16, 2016, and implemented an incremental \$10.4M on December 17, 2016, subject to refund

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

# Pepco DC Distribution Rate Case

<b>Formal Case No.</b>	1139
<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%
<b>Requested Rate of Return</b>	ROE: 10.60%; ROR: 8.00%
<b>Proposed Rate Base (Adjusted)</b>	\$1.7B
<b>Requested Revenue Requirement Increase<sup>(1)</sup> (Updated on February 1, 2017)</b>	\$76.8M
<b>Residential Total Bill % Increase<sup>(2)</sup></b>	4.62%
<b>Notes</b>	<ul style="list-style-type: none"> <li>6/30/16 Pepco-DC filed application with the 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 the 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> <p>Remaining Procedural Schedule:</p> <ul style="list-style-type: none"> <li>Final Briefs Filed: 4/26/17</li> <li>Commission Order Expected: 7/25/17</li> </ul>

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

(2) As proposed by the Company, the full allocation of the CBRC to Residential and MMA customers, along with the proposal for a \$1M Incremental Offset for residential customers, will ensure that residential customers do not receive an increase on the distribution portion of their bill until approximately January 2019 (February 2019 for MMA customers). Upon expiration of the CBRC and Incremental Offset proposed by the Company, this rate increase would translate to a 4.62% total bill increase for a residential customer.

# Delmarva MD Distribution Rate Case – Final Order

<b>Formal Case No.</b>	9424
<b>Authorized Common Equity Ratio</b>	49.1%
<b>Authorized Rate of Return</b>	ROE: 9.60%; ROR: 6.74%
<b>Authorized Rate Base (Adjusted)</b>	\$707M
<b>Authorized Revenue Requirement Increase<sup>(1)</sup></b>	\$38.3M Revenue increase includes net reduction of \$11.8M in new depreciation and amortization expense
<b>Residential Total Bill % Increase</b>	7.3%
<b>Notes</b>	<ul style="list-style-type: none"> <li>• Advanced Metering (“AMI”) system deemed cost-beneficial, and recovery to begin</li> <li>• Legacy meter recovery approved over 10 years, with no return</li> <li>• Post-test period reliability capital placed in service through September 2016 approved</li> <li>• Extension of the Grid Resiliency Program in 2017-2018 was not approved</li> <li>• Disallowance of 100% of Supplemental Executive Retirement Plan (SERP)</li> <li>• Commission Final Order Received: 2/15/17</li> </ul>

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

# **Appendix**

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

# 1Q YTD GAAP EPS Reconciliation

<u>Three Months Ended March 31, 2016</u>	<u>ExGen</u>	<u>ComEd</u>	<u>PECO</u>	<u>BGE</u>	<u>PHI</u>	<u>Other</u>	<u>Exelon</u>
<b>2016 GAAP Earnings (Loss) Per Share</b>	<b>\$0.34</b>	<b>\$0.13</b>	<b>\$0.14</b>	<b>\$0.11</b>	<b>\$(0.34)</b>	<b>\$(0.18)</b>	<b>\$0.19</b>
Mark-to-market impact of economic hedging activities	(0.07)	-	-	-	-	-	(0.07)
Unrealized gains related to NDT fund investments	(0.03)	-	-	-	-	-	(0.03)
Amortization of commodity contract intangibles	(0.01)	-	-	-	-	-	(0.01)
Merger and integration costs	0.01	(0.01)	-	-	0.04	0.05	0.08
Merger commitments	-	-	-	-	0.30	0.12	0.42
Long-lived asset impairments	0.07	-	-	-	-	-	0.07
Reassessment of state deferred income taxes	0.01	-	-	-	-	(0.01)	-
Cost management program	0.01	-	-	-	-	-	0.02
CENG non-controlling interest	0.01	-	-	-	-	-	0.01
<b>2016 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share</b>	<b>\$0.34</b>	<b>\$0.12</b>	<b>\$0.14</b>	<b>\$0.11</b>	<b>\$0.00</b>	<b>\$(0.02)</b>	<b>\$0.68</b>

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

# 1Q YTD GAAP EPS Reconciliation (continued)

<u>Three Months Ended March 31, 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>\$0.46</b>	<b>\$0.15</b>	<b>\$0.14</b>	<b>\$0.13</b>	<b>\$0.15</b>	<b>\$0.04</b>	<b>\$1.07</b>
Mark-to-market impact of economic hedging activities	0.03	-	-	-	-	-	0.03
Unrealized gains related to NDT fund investments	(0.10)	-	-	-	-	-	(0.10)
Merger and integration costs	0.02	-	-	0.01	-	-	0.03
Merger commitments	(0.02)	-	-	-	(0.06)	(0.07)	(0.15)
Reassessment of state deferred income taxes	-	-	-	-	-	(0.02)	(0.02)
Tax settlements	(0.01)	-	-	-	-	-	(0.01)
Bargain purchase gain	(0.24)	-	-	-	-	-	(0.24)
CENG non-controlling interest	0.04	-	-	-	-	-	0.04
<b>2017 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share</b>	<b>\$0.18</b>	<b>\$0.15</b>	<b>\$0.14</b>	<b>\$0.14</b>	<b>\$0.09</b>	<b>(\$0.05)</b>	<b>0.65</b>

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

# GAAP to Operating Adjustments

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- **Exelon's 2017 adjusted (non-GAAP) operating earnings exclude 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 acquisition date
  - 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
  - Non-cash impact of the remeasurement of state deferred income taxes, related to a change in the statutory tax rate
  - Costs incurred related to a cost management program
  - 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 non-controlling interest related to CENG exclusion items



# GAAP to Non-GAAP Reconciliations

YE 2017 Exelon FFO Calculation (\$M) <sup>(1,2)</sup>		YE 2017 Exelon Adjusted Debt Calculation (\$M) <sup>(1,2)</sup>	
GAAP Operating Income	\$4,300	Long-Term Debt (including current maturities)	\$32,650
Depreciation & Amortization	<u>\$3,200</u>	Short-Term Debt	\$1,575
EBITDA	\$7,500	+ PPA Imputed Debt <sup>(5)</sup>	\$350
+/- Non-operating activities and nonrecurring items <sup>(3)</sup>	\$200	+ Operating Lease Imputed Debt <sup>(6)</sup>	\$875
- Interest Expense	(\$1,425)	+ Pension/OPEB Imputed Debt <sup>(7)</sup>	\$3,450
+ Current Income Tax (Expense)/Benefit	(\$75)	- Off-Credit Treatment of Debt <sup>(8)</sup>	(\$2,225)
+ Nuclear Fuel Amortization	\$1,050	- Surplus Cash Adjustment <sup>(9)</sup>	(\$650)
+/- Other S&P Adjustments <sup>(4)</sup>	<u>\$375</u>	+/- Other S&P Adjustments <sup>(4)</sup>	<u>\$300</u>
<b>= FFO (a)</b>	<b>\$7,625</b>	<b>= Adjusted Debt (b)</b>	<b>\$36,325</b>

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

- (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

# GAAP to Non-GAAP Reconciliations

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

Long-Term Debt (including current maturities)	\$9,550
Short-Term Debt	\$650
- Surplus Cash Adjustment	<u>(\$375)</u>
<b>= Net Debt (a)</b>	<b>\$9,825</b>

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

GAAP Operating Income	\$1,550
Depreciation & Amortization	<u>\$1,200</u>
EBITDA	\$2,750
+/- Non-operating activities and nonrecurring items <sup>(2)</sup>	\$300
<b>= Operating EBITDA (b)</b>	<b>\$3,050</b>

## YE 2017 Book Debt / EBITDA

Net Debt (a)		
	=	3.2x
Operating EBITDA (b)		

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

Long-Term Debt (including current maturities)	\$9,550
Short-Term Debt	\$650
- Surplus Cash Adjustment	<u>(\$375)</u>
- Nonrecourse Debt	<u>(\$2,550)</u>
<b>= Net Debt (a)</b>	<b>\$7,275</b>

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

GAAP Operating Income	\$1,550
Depreciation & Amortization	<u>\$1,200</u>
EBITDA	\$2,750
+/- Non-operating activities and nonrecurring items <sup>(2)</sup>	\$300
- EBITDA from projects financed by nonrecourse debt	<u>(\$250)</u>
<b>= Operating EBITDA (b)</b>	<b>\$2,800</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

# GAAP to Non-GAAP Reconciliations

Operating ROE Reconciliation (\$M) <sup>(1)</sup>	ACE	Delmarva	Pepco	Legacy EXC	Consolidated EU
Net Income (GAAP) <sup>(1)</sup>	\$87	\$120	\$208	\$1,156	\$1,571
Operating Exclusions	(\$24)	(\$31)	(\$28)	\$160	\$77
Adjusted Operating Earnings <sup>(1)</sup>	\$63	\$89	\$180	\$1,316	\$1,648
Average Equity	\$970	\$1,240	\$2,210	\$12,176	\$16,597
<b>Operating ROE (Adjusted Operating Earnings/Average Equity)</b>	<b>6.5%</b>	<b>7.2%</b>	<b>8.2%</b>	<b>10.8%</b>	<b>9.9%</b>

ExGen Adjusted O&M Reconciliation (\$M) <sup>(2)</sup>	2017
<b>GAAP O&amp;M</b>	<b>\$5,800</b>
Decommissioning <sup>(3)</sup>	25
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses <sup>(4)</sup>	(425)
O&M for managed plants that are partially owned	(425)
Other	(100)
<b>Adjusted O&amp;M (Non-GAAP)</b>	<b>\$4,850</b>

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

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

(3) Reflects earnings neutral O&M

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

# 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)	\$1,075	\$725	\$700	\$1,225	\$3,300	(\$225)	\$6,825
Other cash from investing activities	-	-	\$25	-	(\$275)	-	(\$250)
Intercompany receivable adjustment	(\$350)	-	-	-	-	\$350	-
Counterparty collateral activity	-	-	-	-	\$475	-	\$475
<b>Adjusted Cash Flow from Operations</b>	<b>\$725</b>	<b>\$725</b>	<b>\$725</b>	<b>\$1,225</b>	<b>\$3,525</b>	<b>\$125</b>	<b>\$7,075</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)	\$1,075	\$175	\$175	\$125	\$25	\$375	\$1,975
Dividends paid on common stock	\$425	\$300	\$200	\$325	\$650	(\$650)	\$1,225
Intercompany receivable adjustment	\$350	-	-	-	-	(\$350)	-
<b>Financing Cash Flow</b>	<b>\$1,850</b>	<b>\$475</b>	<b>\$375</b>	<b>\$450</b>	<b>\$675</b>	<b>(\$625)</b>	<b>\$3,200</b>

Exelon Total Cash Flow Reconciliation <sup>(1)</sup>	2017
<b>GAAP Beginning Cash Balance</b>	<b>\$650</b>
Adjustment for Cash Collateral Posted	\$400
Adjusted Beginning Cash Balance <sup>(3)</sup>	\$1,050
Net Change in Cash (GAAP) <sup>(2)</sup>	\$725
Adjusted Ending Cash Balance <sup>(3)</sup>	\$1,775
Adjustment for Cash Collateral Posted	(\$900)
<b>GAAP Ending Cash Balance</b>	<b>\$875</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