

Earnings Conference Call 3rd Quarter 2016

October 26, 2016



Cautionary Statements Regarding Forward-Looking Information

This presentation contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by Exelon Corporation, Exelon Generation Company, LLC, Commonwealth Edison Company, PECO Energy Company, Baltimore Gas and Electric Company, Pepco Holdings LLC (PHI), 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 2015 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 23; (2) PHI's 2015 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 16; (3) Exelon's Third Quarter 2016 Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors; (b) Part 1, Financial Information, ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 18; and (4) 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 presentation. 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 (non-GAAP) operating earnings, adjusted (non-GAAP) operating and maintenance expense, total gross margin, and adjusted cash flow from operations (non-GAAP) or free cash flow. Adjusted (non-GAAP) 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 costs, certain costs incurred associated with the PHI acquisition, merger commitments related to the settlement of the PHI acquisition, the impairment of certain long-lived assets, plant retirements and divestitures, costs related to the cost management program, and the non-controlling interest in CENG. Adjusted (non-GAAP) 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, and the impact from operating and maintenance expense related to variable interest entities at Generation. Total gross margin (non-GAAP) is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners, the operating services agreement with Fort Calhoun, variable interest entities and net of direct cost of sales for certain Constellation businesses. Adjusted cash flow from operations (non-GAAP) or free cash flow primarily includes net cash flows from operating activities and net cash flows from investing activities excluding capital expenditures at ownership and nuclear fuel expense. Due to the forward-looking nature of any forecasted non-GAAP measures, information to reconcile the forecast adjusted (non-GAAP) measures to the most directly comparable GAAP measure is not currently available, as management is unable to project all of these items for future periods.

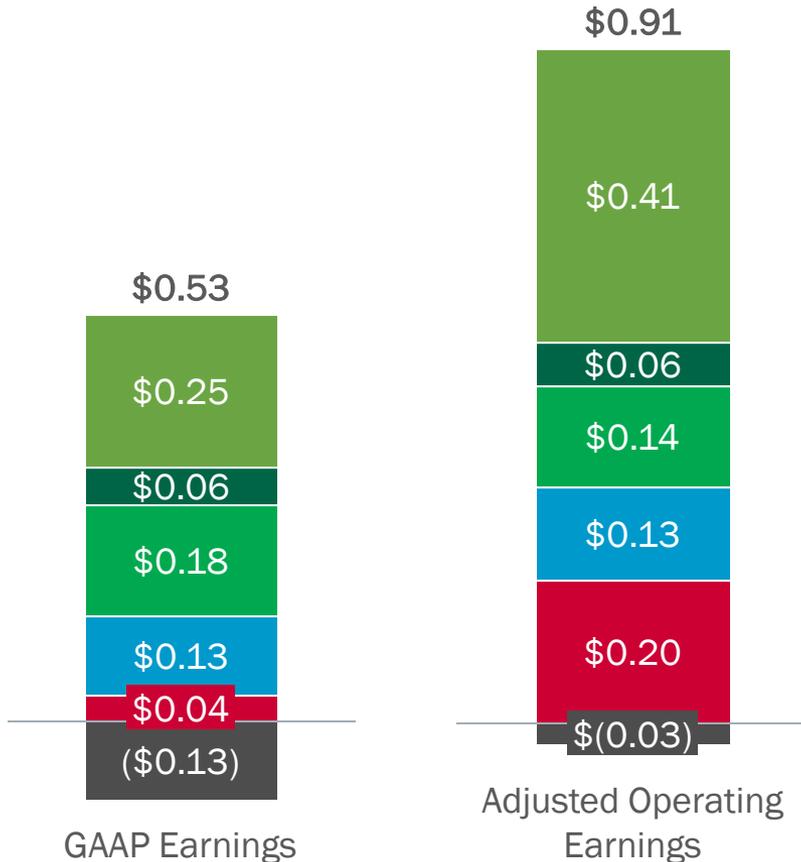
Non-GAAP Financial Measures Continued

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

These non-GAAP financial measures are not a presentation defined under GAAP and may not be comparable to other companies' presentation. Exelon has provided these non-GAAP financial 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. Reconciliations of these non-GAAP measures to the most comparable GAAP measures are provided in the footnotes, appendices and attachments to this presentation.

Strong 3rd Quarter Results

Q3 EPS Results^(1,2)



- GAAP earnings were \$0.53/share in Q3 2016 vs. \$0.69/share in Q3 2015
- Adjusted (non-GAAP) operating earnings were \$0.91/share in Q3 2016 vs. \$0.83/share in Q3 2015, exceeding our guidance range of \$0.65-\$0.75/share

■ ExGen
 ■ BGE
 ■ PHI
 ■ PECO
 ■ ComEd
 ■ HoldCo

(1) Refer to the Earnings Release Attachments for additional details and to the Appendix for a reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS

(2) Amounts may not add due to rounding

Best in Class Operations

Exelon Utilities Operational Metrics

Operations	Metric	YTD 2016 ⁽¹⁾			
		BGE	PECO	ComEd	PHI
Electric Operations	OSHA Recordable Rate	Yellow	Green	Green	Yellow
	2.5 Beta SAIFI (Outage Frequency)	Yellow	Green	Green	Orange
	2.5 Beta CAIDI (Outage Duration)	Green	Green	Green	Orange
Customer Operations	Customer Satisfaction	Green	Green	Green	N/A
	Service Level % of Calls Answered in <30 sec	Green	Green	Green	Green
	Abandon Rate	Green	Green	Green	Green
Gas Operations	Percent of Calls Responded to in <1 Hour	Green	Green	No Gas Operations	Green

⁽¹⁾Note: 2.5 Beta SAIFI is YE projection

Exelon Utilities has identified and transferred best practices at each of its utilities to improve operating performance in areas such as:

- System Performance
- Emergency Preparedness
- Corrective and Preventive Maintenance

Q1	Q2
Q3	Q4

Exelon Generation Operational Metrics

- Continued best in class performance across our Nuclear fleet:
 - Q3 Capacity Factor of 96.3%
 - Most MWhs ever produced in a quarter
 - No unplanned outages in Q3
- Strong performance across our Fossil and Renewable fleet:
 - Q3 Renewables energy capture: 95.2%
 - Q3 Power dispatch match: 97.9%
- Closed on ConEdison Solutions transaction, adding more than 560,000 customers

Exelon Utilities Distribution Rate Case Summary

ACE Electric Settlement		Pepco DC Filing	
Authorized Revenue Requirement Increase ⁽¹⁾	\$45M	Requested Revenue Requirement Increase ⁽¹⁾	\$82.1M
Authorized ROE	9.75%	Requested ROE	10.60%
Common Equity Ratio	49.48%	Requested Common Equity Ratio	49.14%
Commission Approved Settlement	8/24/16	Order Expected	7/25/17

Pepco MD Filing		Delmarva DE Electric Filing	
Requested Revenue Requirement Increase ⁽¹⁾	\$102.8M	Requested Revenue Requirement Increase ⁽¹⁾	\$62.8M
Requested ROE	10.60%	Requested ROE	10.60%
Requested Common Equity Ratio	49.60%	Requested Common Equity Ratio	49.40%
Order Expected	11/15/16	Order Expected	Q3 2017

ComEd Filing		Delmarva DE Gas Filing	
Requested Revenue Requirement Increase ⁽²⁾	\$132M	Requested Revenue Requirement Increase ⁽¹⁾	\$21.5M
Requested ROE	8.64%	Requested ROE	10.60%
Requested Common Equity Ratio	46%	Requested Common Equity Ratio	49.40%
Order Expected	Dec 2016	Order Expected	Q3 2017

Delmarva MD Filing	
Requested Revenue Requirement Increase ⁽¹⁾	\$57.0M
Requested ROE	10.60%
Requested Common Equity Ratio	49.10%
Order Expected	2/17/17

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

(2) Amounts represent ComEd's position filed in surrebuttal testimony on August 19, 2016

Status of New York and Illinois Nuclear Plants

New York Nuclear Plants: Nine Mile Point, Ginna, FitzPatrick

- EPS uplift of \$0.08-0.10 per share and \$350M of additional after-tax cash flow through 2020 (Ginna and Nine Mile Point I & II)⁽¹⁾
- Federal court challenge filed on October 19
- FitzPatrick acquisition⁽³⁾:
 - EPS contribution of \$0.02-0.08 per share
 - NY PSC approval expected in November
 - FERC approval requested for November
 - NRC approval expected Q1 2017
 - Refueling planned for January 2017
- NYSERDA contracts for all 3 plants expected to be signed in November

Illinois Nuclear Plants: Clinton and Quad Cities

- 2019 EPS run rate of up to \$0.07 per share and up to \$75M of pre-tax cash flow⁽²⁾
- June 22: Notification to NRC on intent to close Clinton and Quad Cities stations
- July 7: Notification to PJM on intent to retire Quad Cities station and not offer it into 20/21 capacity auction
- On or about December 1: Notification due to MISO on intent to retire Clinton
- Illinois Legislature veto session scheduled November 15-17 and November 29 - December 1

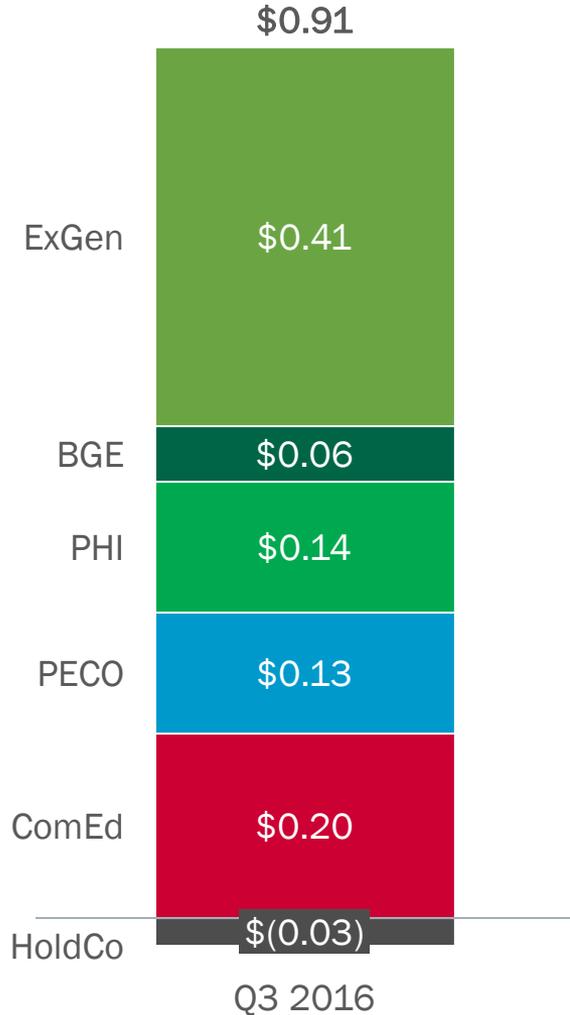
(1) \$350M is solely from implementation of CES program and does not include additional cash benefits from CENG loan repayment and special distribution

(2) Impacts based on February 29, 2016 pricing and excludes decommissioning costs

(3) Estimates are subject to change based on final purchase accounting and April 1, 2017 closing date, and equates to an EPS of \$0.02-0.08

3rd Quarter Adjusted Operating Earnings Drivers

Q3 Adjusted Operating EPS Results^(1,2)



Q3 2016 vs. Guidance (\$0.65 - \$0.75)

Exelon Utilities

- ↑ Favorable weather
- ↑ Reduced Storm Activity
- ↑ Lower O&M

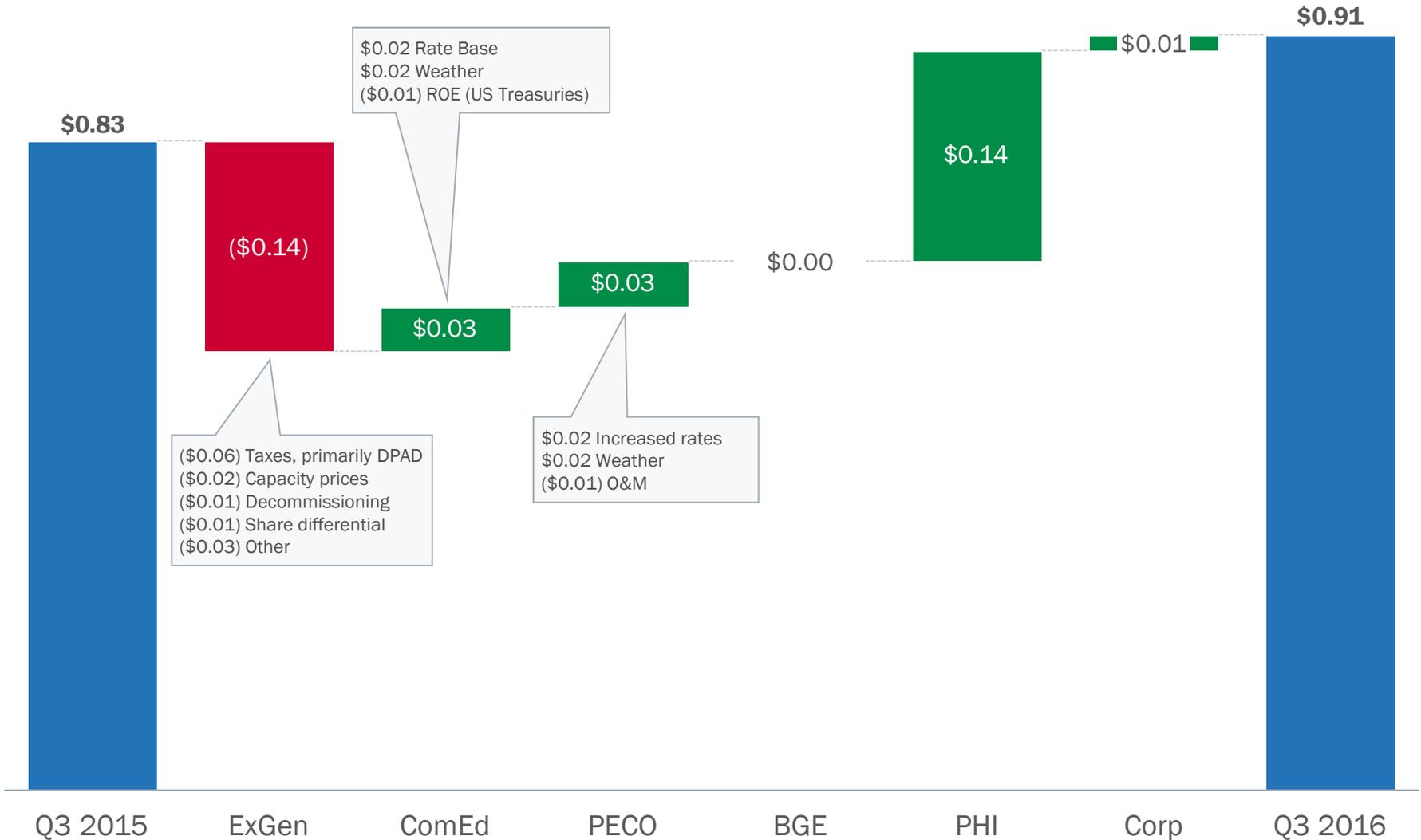
Exelon Generation

- ↑ Lower cost to serve
- ↑ Strong performance at Constellation

(1) Refer to the Earnings Release Attachments for additional details and to the Appendix for a reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS

(2) Amounts may not add due to rounding

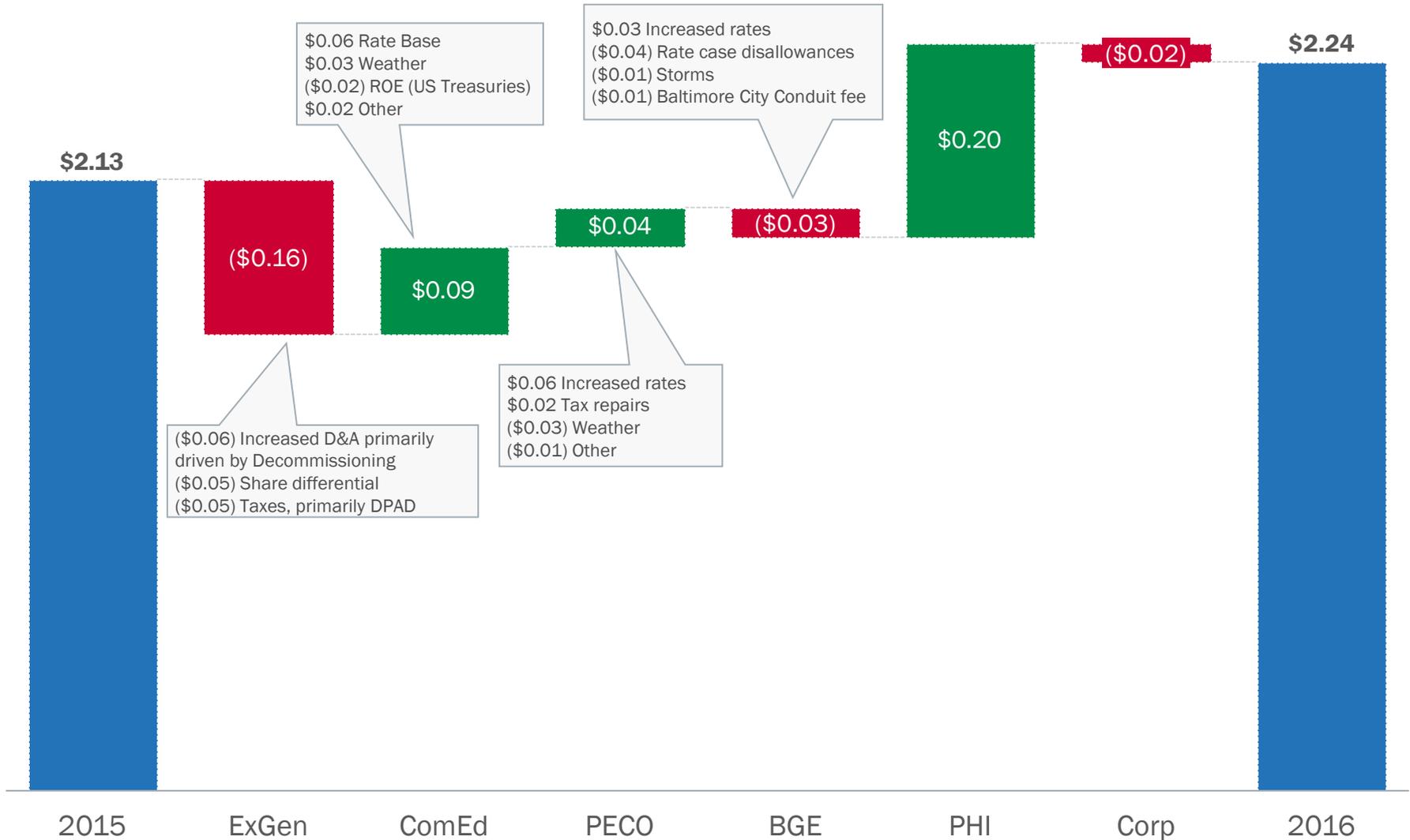
3rd Quarter Adjusted Operating Earnings Waterfall (1,2)



(1) Refer to the Earnings Release Attachments for additional details and to the Appendix for a reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS

(2) Amounts may not add due to rounding

YTD Adjusted Operating Earnings Waterfall (1,2)

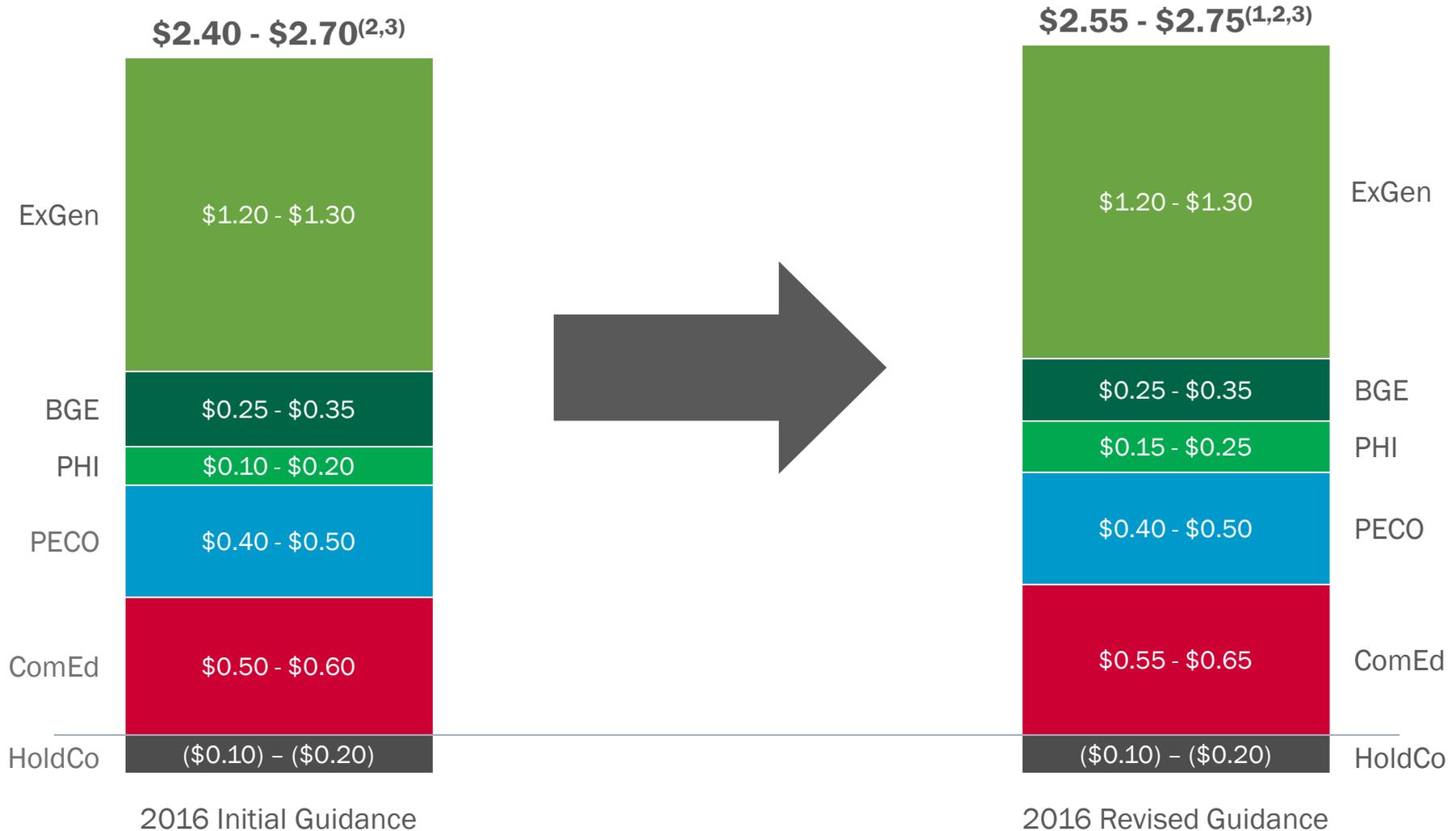


(1) Refer to the Earnings Release Attachments for additional details and to the Appendix for a reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS

(2) Amounts may not add due to rounding

Raising 2016 Full-Year Guidance on Strong Utility Results

2016 Adjusted Operating Earnings



(1) ComEd ROE based on 30-year average Treasury yield of 2.47% as of 9/30/16

(2) 2016 earnings guidance based on expected average outstanding shares of 926M. Refer to Appendix for a reconciliation of adjusted non-GAAP operating EPS guidance to GAAP EPS.

(3) Amounts may not add due to rounding

Exelon Utilities Distribution Rate Case Schedule

	10/16	11/16	12/16	1/17	2/17	3/17	4/17
ComEd Electric Distribution Formula Rate	Proposed Order Oct 20		Final Order Expected by Dec 9				
Pepco Electric Distribution Rates - MD	Final Reply Briefs Oct 26	Final Order Expected Nov 15					
Pepco Electric Distribution Rates - DC			Intervenor Direct Due Dec 14		Rebuttal Testimony Due Feb 1	Evidentiary Hearings Mar 15-21	Final Reply Briefs Apr 24
Delmarva Electric Distribution Rates - DE		Intervenor Direct Due Nov 23		Rebuttal Testimony Due Jan 11		Evidentiary Hearings Mar 7-9	
Delmarva Gas Distribution Rates - DE			Intervenor Direct Due Dec 9		Rebuttal Testimony Due Feb 10		Evidentiary Hearings Apr 5-7
Delmarva Electric Distribution Rates - MD	Rebuttal Testimony Due Oct 18	Evidentiary Hearings Nov 2-10	Final Reply Briefs Dec 14		Commission Order Expected Feb 17		

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

Exelon Generation: Gross Margin Update

Gross Margin Category (\$M) ⁽¹⁾	September 30, 2016				Change from June 30, 2016		
	2016	2017	2018	2019	2016	2017	2018
Open Gross Margin ⁽³⁾ (including South, West, Canada hedged gross margin)	\$4,450	\$5,200	\$5,350	\$5,050	\$(300)	\$(450)	\$(550)
Mark-to-Market of Hedges ^(3,4)	\$2,900	\$1,250	\$500	\$300	\$450	\$450	\$300
Power New Business / To Go	\$50	\$600	\$900	\$950	\$(100)	\$(100)	-
Non-Power Margins Executed	\$400	\$150	\$100	\$50	\$50	-	-
Non-Power New Business / To Go	\$50	\$300	\$400	\$450	\$(50)	-	-
Total Gross Margin ^(2,5,6)	\$7,850	\$7,500	\$7,250	\$6,800	\$50	\$(100)	\$(250)
CES Gross Margin (GINNA, Nine Mile Point I & II) ⁽⁷⁾	\$0	\$100	\$150	\$200			
FitzPatrick Gross Margin ^(5,8)	\$0	\$200	\$250	\$300			
Total Gross Margin including CES and FitzPatrick	\$7,850	\$7,800	\$7,650	\$7,300			

Recent Developments

- Behind ratable hedging position reflects the fundamental upside we see in power prices
 - Generation ~12-15% open in 2017
 - Power position ~7-10% behind ratable, considering cross-commodity hedges in 2017

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

2) Total Gross Margin (Non-GAAP) is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners, operating services agreement with Fort Calhoun and variable interest entities. Total Gross Margin is also net of direct cost of sales for certain Constellation businesses. See Slide 26 for a Non-GAAP to GAAP reconciliation of Total Gross Margin.

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

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

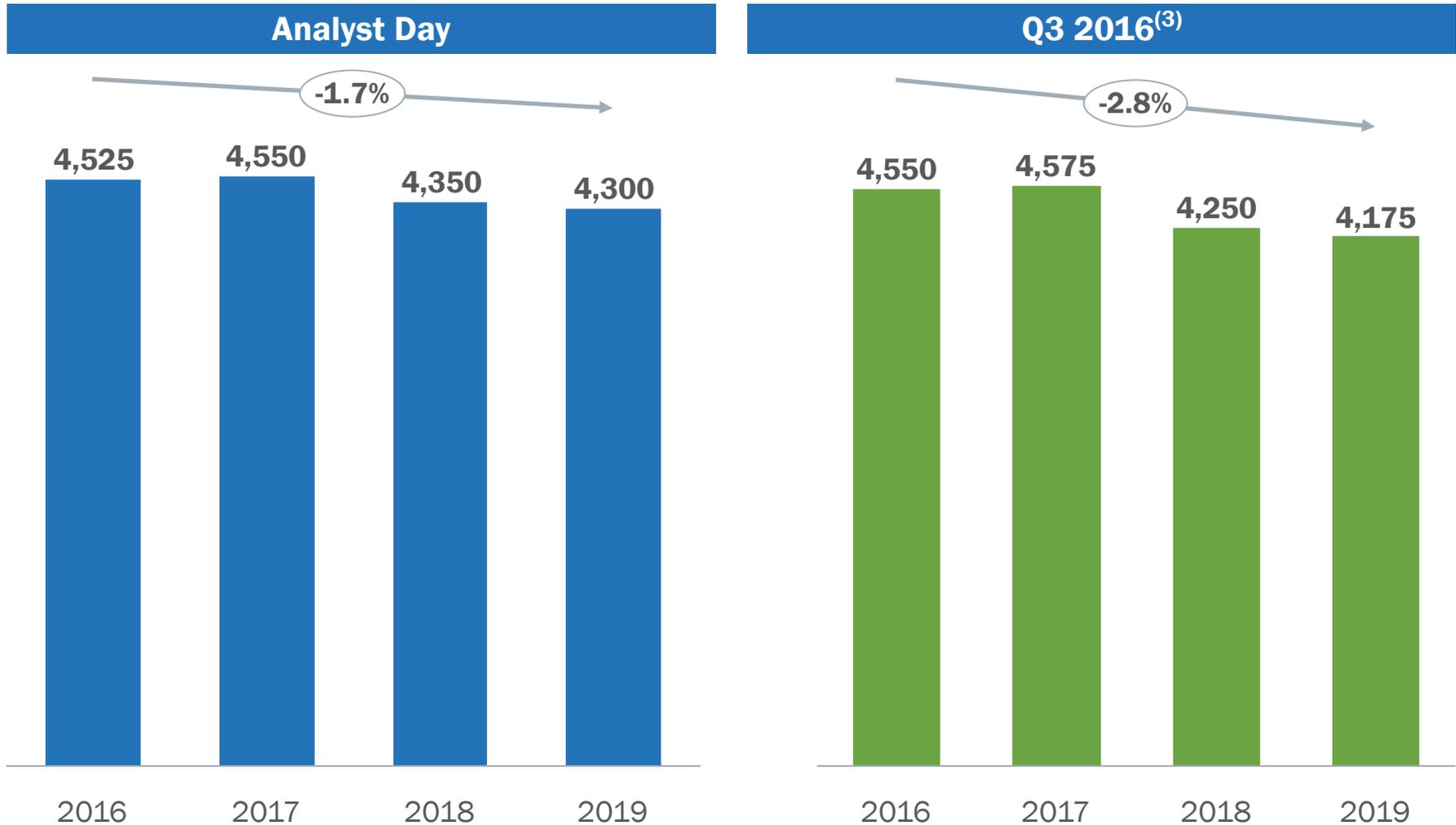
5) Based on September 30, 2016 market conditions

6) Excludes Clinton, Quad Cities, and Oyster Creek starting in June 2017, June 2018, and December 2019, respectively. Does not include the impact of the CES program in NY or the acquisition of FitzPatrick.

7) 2019 ZEC value based on September 30, 2016 pricing

8) Estimates are subject to change based on final purchase accounting and April 1, 2017 closing date, and equates to an EPS of \$0.02-0.08

Further Reducing O&M at ExGen^(1,2)



Finding additional savings at ExGen -- O&M down \$100M in 2018 and \$125M in 2019

(1) O&M reflects the retirement of Clinton and Quad Cities. In addition, the run rate of D&A and TOTI declines by \$100M with the retirements.
 (2) O&M does not include cost of FitzPatrick acquisition
 (3) Refer to slide 42 in the appendix for a reconciliation of adjusted (non-GAAP) O&M to GAAP O&M

2016 Projected Sources and Uses of Cash

(\$ in millions) ⁽¹⁾	BGE	ComEd	PECO	PHI	Total Utilities	ExGen	Corp ⁽⁹⁾	Exelon 2016E	Cash Balance
Beginning Cash Balance ⁽²⁾⁽¹⁰⁾									8,100
Adjusted Cash Flow from Operations ^(3,4)	700	1,525	775	775	3,775	3,600	(525)	6,850	
Base CapEx and Nuclear Fuel ⁽⁵⁾	0	0	0	0	0	(2,325)	(100)	(2,425)	
Free Cash Flow	700	1,525	775	775	3,775	1,275	(625)	4,425	
Debt Issuances	850	1,200	300	175	2,525	1,000	1,800	5,325	
Debt Retirements	(575)	(675)	(300)	(325)	(1,875)	0	0	(1,875)	
Project Financing	0	0	0	0	0	275	0	275	
PHI Purchase	0	0	0	0	0	0	(6,925)	(6,925)	
Contribution from Parent	25	625	0	1,300	1,950	0	(1,950)	0	
Other Financing ⁽⁶⁾	50	250	25	(875)	(550)	(700)	1,225	(25)	
Financing	350	1,400	25	275	2,050	575	(5,850)	(3,225)	
Total Free Cash Flow and Financing Growth	1,050	2,925	800	1,050	5,825	1,850	(6,475)	1,200	
Utility Investment	(850)	(2,625)	(650)	(1,050)	(5,175)	0	0	(5,175)	
ExGen Growth ^{(5),(7)}	0	0	0	0	0	(1,100)	0	(1,100)	
Acquisitions and Divestitures	0	0	0	0	0	(250)	0	(250)	
Equity Investments	0	0	0	0	0	(100)	0	(100)	
Dividend ⁽⁸⁾	0	0	0	0	0	0	(1,175)	(1,175)	
Other CapEx and Dividend	(850)	(2,625)	(650)	(1,050)	(5,175)	(1,450)	(1,175)	(7,800)	
Total Cash Flow	200	300	150	0	650	400	(7,650)	(6,600)	
Ending Cash Balance ⁽¹⁾⁽²⁾									1,500

- (1) All amounts rounded to the nearest \$25M. Figures may not add due to rounding.
- (2) Gross of posted counterparty collateral
- (3) Excludes counterparty collateral activity
- (4) Adjusted Cash Flow from Operations (non-GAAP) primarily includes net cash flows from operating activities and net cash flows from investing activities excluding capital expenditures, net M&A, and equity investments. Please refer to slide 41 for reconciliations to GAAP cash flow measures.
- (5) Figures reflect cash CapEx and CENG fleet at 100%
- (6) Other Financing primarily includes expected changes in short-term debt, money pool borrowings, and tax sharing from the parent
- (7) ExGen Growth CapEx includes Texas CCGTs, West Medway, AGE, Nuclear relicensing, Nuclear Upgrades, Merger Commitments excl. Solar, Retail Growth & Distributed Energy, Michigan Wind 3, Bluestem Wind, and Clinton Battery Storage
- (8) Dividends are subject to declaration by the Board of Directors
- (9) Includes cash flow activity from Holding Company, eliminations, and other corporate entities
- (10) Includes PHI cash on hand at time of merger close

Consistent and reliable free cash flows

Operational excellence and financial discipline drives free cash flow reliability

- ✓ Generating ~\$4.4B of free cash flow, including \$1.3B 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

- ✓ Completed \$6.9B merger with PHI
- ✓ HoldCo issued \$1.8B of Long-term debt in April
- ✓ ExGen plans to issue \$1.0B of Long-term debt to fund dividend to parent to support LKE

Enable growth & value creation

Creating value for customers, communities and shareholders

- ✓ Investing \$6.3B, with \$5.2B at the Utilities and \$1.1B at ExGen

The Exelon Value Proposition

- **Regulated Utility Growth** with utility EPS rising 7-9% annually from 2016-2020 and rate base growth of 6.1%, 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 5 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⁽¹⁾,
 - Debt reduction; and,
 - Modest contracted generation investments

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

Exelon Generation Disclosures

September 30, 2016

Portfolio Management Strategy

Strategic Policy Alignment

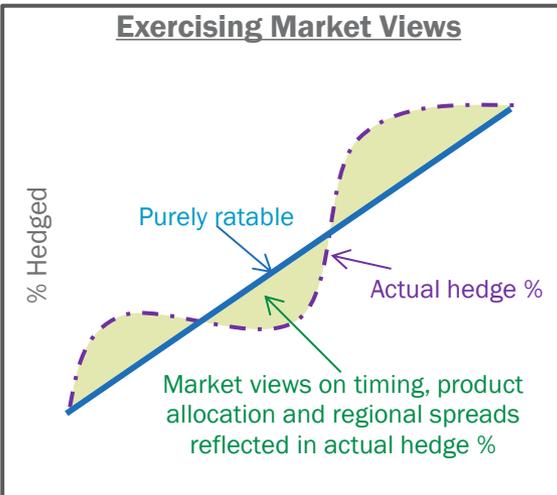
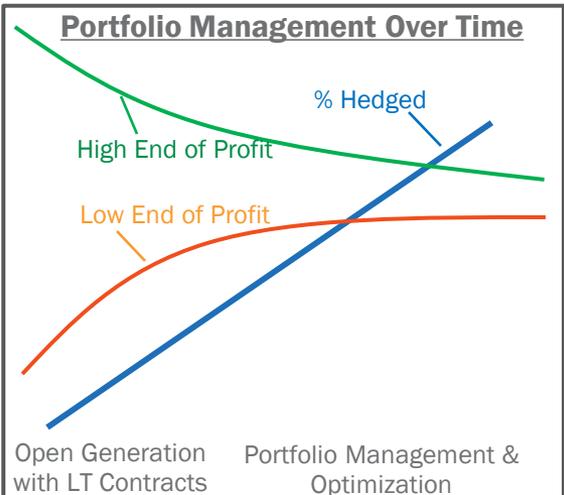
- Aligns hedging program with financial policies and financial outlook
- Establish minimum hedge targets to meet financial objectives of the company (dividend, credit rating)
- Hedge enough commodity risk to meet future cash requirements under a stress scenario

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

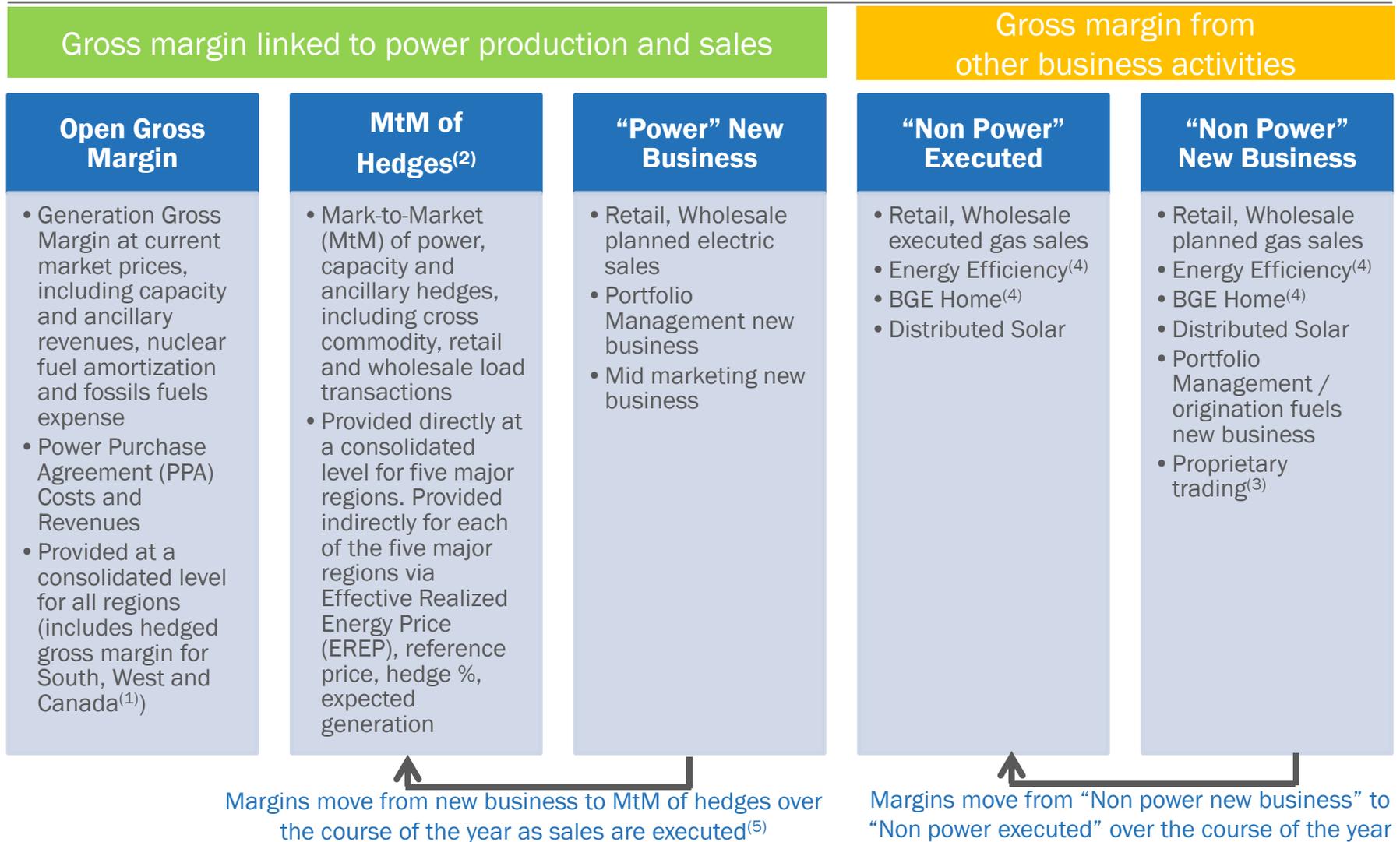


Protect Balance Sheet

Ensure Earnings Stability

Create Value

Components of Gross Margin Categories



(1) Hedged gross margins for South, West & Canada region will be included with Open Gross Margin, and no expected generation, hedge %, EREP or reference prices provided for this region
 (2) MtM of hedges provided directly for the five larger regions; MtM of hedges is not provided directly at the regional level but can be easily estimated using EREP, reference price and hedged MWh
 (3) Proprietary trading gross margins will generally remain within “Non Power” New Business category and only move to “Non Power” Executed category upon management discretion
 (4) Gross margin for these businesses are net of direct “cost of sales”
 (5) Margins for South, West & Canada regions and optimization of fuel and PPA activities captured in Open Gross Margin

ExGen Disclosures

Gross Margin Category (\$M) ⁽¹⁾	2016	2017	2018	2019
Open Gross Margin (including South, West & Canada hedged GM) ⁽³⁾	\$4,450	\$5,200	\$5,350	\$5,050
Mark-to-Market of Hedges ^(3,4)	\$2,900	\$1,250	\$500	\$300
Power New Business / To Go	\$50	\$600	\$900	\$950
Non-Power Margins Executed	\$400	\$150	\$100	\$50
Non-Power New Business / To Go	\$50	\$300	\$400	\$450
Total Gross Margin^(2,6)	\$7,850	\$7,500	\$7,250	\$6,800

Reference Prices ⁽⁵⁾	2016	2017	2018	2019
Henry Hub Natural Gas (\$/MMbtu)	\$2.46	\$3.09	\$2.91	\$2.81
Midwest: NiHub ATC prices (\$/MWh)	\$25.87	\$28.49	\$27.78	\$27.66
Mid-Atlantic: PJM-W ATC prices (\$/MWh)	\$28.84	\$32.84	\$31.08	\$30.44
ERCOT-N ATC Spark Spread (\$/MWh) <i>HSC Gas, 7.2HR, \$2.50 VOM</i>	\$1.54	\$3.13	\$3.28	\$3.57
New York: NY Zone A (\$/MWh)	\$26.51	\$32.28	\$31.43	\$31.23
New England: Mass Hub ATC Spark Spread(\$/MWh) <i>ALQN Gas, 7.5HR, \$0.50 VOM</i>	\$5.52	\$7.10	\$7.29	\$7.81

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

(2) Total Gross Margin (Non-GAAP) is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners, operating services agreement with Fort Calhoun and variable interest entities. Total Gross Margin is also net of direct cost of sales for certain Constellation businesses. Refer to slide 26 for a reconciliation of Total Gross Margin to the most comparable GAAP measure.

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

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

(5) Based on September 30, 2016 market conditions

(6) Excludes Clinton and Quad Cities starting in June 2017 and June 2018 respectively. Does not include the impact of the CES program or FitzPatrick acquisition in NY.

ExGen Disclosures

Generation and Hedges	2016	2017	2018	2019
<u>Exp. Gen (GWh)⁽¹⁾</u>	191,800	196,600	188,700	186,200
Midwest ⁽⁶⁾	98,000	90,800	81,000	77,500
Mid-Atlantic ⁽²⁾	61,300	60,400	60,200	60,000
ERCOT	12,100	24,200	29,700	30,100
New York ⁽²⁾	9,500	9,200	9,000	9,400
New England	10,900	12,000	8,800	9,200
<u>% of Expected Generation Hedged⁽³⁾</u>	98%-101%	85%-88%	54%-57%	23%-26%
Midwest ⁽⁶⁾	97%-100%	79%-82%	48%-51%	18%-21%
Mid-Atlantic ⁽²⁾	99%-102%	91%-94%	59%-62%	27%-30%
ERCOT	99%-102%	84%-87%	54%-57%	28%-31%
New York ⁽²⁾	96%-99%	93%-96%	68%-71%	23%-26%
New England	100%-103%	90%-93%	49%-52%	22%-25%
<u>Effective Realized Energy Price (\$/MWh)⁽⁴⁾</u>				
Midwest ⁽⁶⁾	\$35.50	\$32.50	\$30.50	\$30.50
Mid-Atlantic ⁽²⁾	\$48.00	\$43.50	\$39.50	\$42.00
ERCOT ⁽⁵⁾	\$18.50	\$7.50	\$4.50	\$3.00
New York ⁽²⁾	\$59.50	\$48.50	\$39.00	\$35.00
New England ⁽⁵⁾	\$28.50	\$15.50	\$8.50	\$8.00

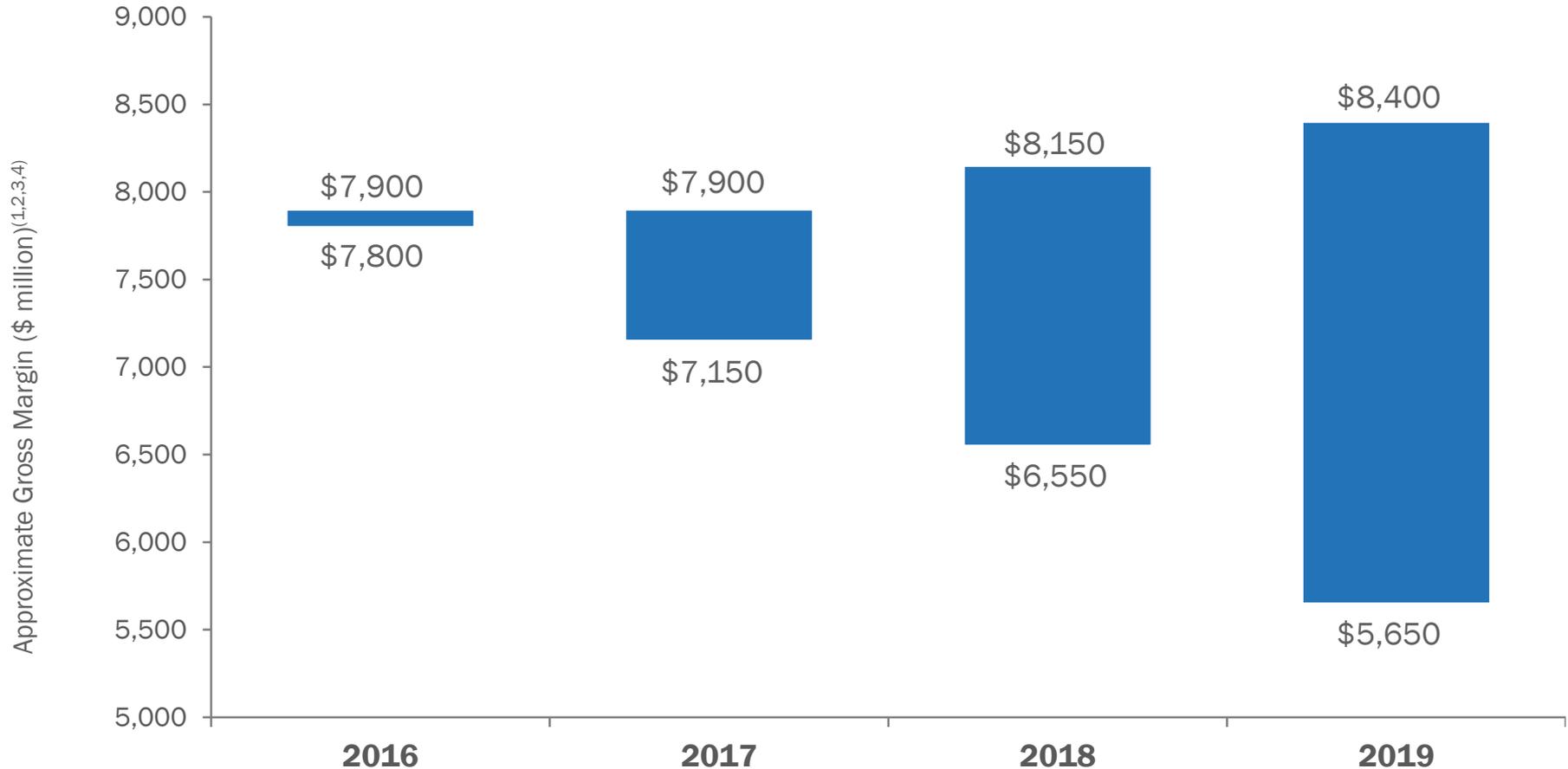
- (1) Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Expected generation assumes 12 refueling outages in 2016, 14 in 2017, 12 in 2018, and 10 in 2019 at Exelon-operated nuclear plants and Salem. Expected generation assumes capacity factors of 94.6%, 93.6%, 93.5% and 94.6% in 2016, 2017, 2018 and 2019 respectively at Exelon-operated nuclear plants, at ownership. These estimates of expected generation in 2017, 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 and acquisition of FitzPatrick
- (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 and RPM capacity revenue, 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) Excludes Clinton and Quad Cities starting in June 2017 and June 2018, respectively. Does not include the impact of the ZEC program.

ExGen Hedged Gross Margin Sensitivities

Gross Margin Sensitivities (With Existing Hedges) ⁽¹⁾	2016	2017	2018	2019
Henry Hub Natural Gas (\$/Mmbtu)				
+ \$1/Mmbtu	\$(10)	\$75	\$275	\$400
- \$1/Mmbtu	\$40	\$(55)	\$(260)	\$(365)
NiHub ATC Energy Price				
+ \$5/MWh	\$5	\$100	\$220	\$300
- \$5/MWh	\$(5)	\$(100)	\$(220)	\$(295)
PJM-W ATC Energy Price				
+ \$5/MWh	\$(5)	\$30	\$120	\$220
- \$5/MWh	\$5	\$(15)	\$(125)	\$(215)
NYPP Zone A ATC Energy Price				
+ \$5/MWh	-	-	\$15	\$35
- \$5/MWh	-	-	\$(15)	\$(35)
Nuclear Capacity Factor				
+/- 1%	+/- \$10	+/- \$35	+/- \$30	+/- \$30

(1) Based on September 30, 2016 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. Total Gross Margin (Non-GAAP) is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners, operating services agreement with Fort Calhoun and variable interest entities. Total Gross Margin is also net of direct cost of sales for certain Constellation businesses. Refer to slide 26 for a reconciliation of Total Gross Margin to the most comparable GAAP measure.

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 2017 and 2018 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, 2016
- (2) Gross Margin Upside/Risk based on commodity exposure which includes open generation and all committed transactions
- (3) Gross Margin (Non-GAAP) is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners, operating services agreement with Fort Calhoun and variable interest entities. Total Gross Margin is also net of direct cost of sales for certain Constellation businesses. Excludes EDF's equity ownership share of the CENG Joint Venture. Refer to slide 26 for a reconciliation of Total Gross Margin to the most comparable GAAP measure.
- (4) Excludes Clinton, Quad Cities, and Oyster Creek starting in June 2017, June 2018 and December 2019, respectively. Does not include the impact of the CES program or FitzPatrick acquisition in NY.

Illustrative Example of Modeling Exelon Generation 2017 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	← \$5.2 billion →					
(B)	Expected Generation (TWh)	90.8	60.4	24.2	9.2	12.0	
(C)	Hedge % (assuming mid-point of range)	80.5%	92.5%	85.5%	94.5%	91.5%	
(D=B*C)	Hedged Volume (TWh)	73.1	55.9	20.7	8.7	11.0	
(E)	Effective Realized Energy Price (\$/MWh)	\$32.50	\$43.50	\$7.50	\$48.50	\$15.50	
(F)	Reference Price (\$/MWh)	\$28.49	\$32.84	\$3.13	\$32.28	\$7.10	
(G=E-F)	Difference (\$/MWh)	\$4.01	\$10.66	\$4.37	\$16.22	\$8.40	
(H=D*G)	Mark-to-market value of hedges (\$ million) ⁽¹⁾	\$295	\$595	\$90	\$140	\$90	
(I=A+H)	Hedged Gross Margin (\$ million)	\$6,450					
(J)	Power New Business / To Go (\$ million)	\$600					
(K)	Non-Power Margins Executed (\$ million)	\$150					
(L)	Non-Power New Business / To Go (\$ million)	\$300					
(N=I+J+K+L)	Total Gross Margin ^(2,3)	\$7,500 million					

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

(2) Total Gross Margin (Non-GAAP) is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners operating services agreement with Fort Calhoun and variable interest entities. Total Gross Margin is also net of direct cost of sales for certain Constellation businesses. Refer to slide 26 for a reconciliation of Total Gross Margin to the most comparable GAAP measure.

(3) Excludes Clinton starting in June 2017. Does not include the impact of the CES program or FitzPatrick acquisition in NY.

Additional ExGen Modeling Data

Total Gross Margin Reconciliation (in \$M) ⁽¹⁾	2016	2017	2018	2019
Revenue Net of Purchased Power and Fuel Expense ⁽²⁾⁽³⁾	\$8,625	\$8,200	\$7,975	\$7,525
Other Revenues ⁽⁴⁾	\$(300)	\$(300)	\$(300)	\$(300)
Direct cost of sales incurred to generate revenues for certain Constellation businesses ⁽⁵⁾	\$(475)	\$(400)	\$(425)	\$(425)
Total Gross Margin (Non-GAAP)	\$7,850	\$7,500	\$7,250	\$6,800

Key ExGen Modeling Inputs (in \$M) ⁽¹⁾⁽⁶⁾	2016
Other Revenues (excluding Gross Receipts Tax) ⁽⁴⁾	\$175
Adjusted O&M ⁽⁷⁾	\$(4,550)
Taxes Other Than Income (TOTI) ⁽⁸⁾	\$(350)
Depreciation & Amortization ⁽⁹⁾	\$(1,025)
Interest Expense	\$(350)
Effective Tax Rate	34.0%

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

(2) Revenue net of purchased power and fuel expense (RNF), a non-GAAP measure, is calculated as the GAAP measure of operating revenue less the GAAP measure of purchased power and fuel expense. 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 operating services agreement with Fort Calhoun, 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 and depreciation expense of certain Constellation businesses of Generation

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

(7) ExGen adjusted O&M excludes direct cost of sales for certain Constellation business, P&L neutral decommissioning costs and the impact from O&M related to variable interest entities. Refer to slide 42 for a reconciliation of adjusted (non-GAAP) O&M to GAAP O&M.

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

(9) Depreciation & Amortization excludes the cost of sales impact of ExGen's non-power businesses of \$25M

Additional Disclosures

ComEd April 2016 Distribution Formula Rate

The 2016 distribution formula rate filing established the net revenue requirement used to set the rates that will take effect in January 2017 after the Illinois Commerce Commission's (ICC's) review. There are two components to the annual distribution formula rate filing:

- **Filing Year:** Based on 2015 costs and 2016 projected plant additions.
- **Annual Reconciliation:** For 2015, this amount reconciles the revenue requirement reflected in rates in effect during 2015 to the actual costs for that year. The annual reconciliation impacts cash flow in 2017 but the earnings impact has been recorded in 2015 as a regulatory asset.

Docket #	16-0259
Filing Year	2015 Calendar Year Actual Costs and 2016 Projected Net Plant Additions are used to set the rates for calendar year 2017. Rates currently in effect (docket 15-0287) for calendar year 2016 were based on 2014 actual costs and 2015 projected net plant additions.
Reconciliation Year	Reconciles Revenue Requirement reflected in rates during 2015 to 2015 Actual Costs Incurred. Revenue requirement for 2015 is based on docket 14-0312 (2013 actual costs and 2014 projected net plant additions) approved in December 2014.
Common Equity Ratio	~46% for both the filing and reconciliation year
ROE	8.64% for the filing year (2015 30-yr Treasury Yield of 2.84% + 580 basis point risk premium) and 8.59% for the reconciliation year (2015 30-yr Treasury Yield of 2.79% + 580 basis point risk premium – 5 basis points performance metrics penalty). For 2016 and 2017, 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
Requested Rate of Return	~7% for both the filing and reconciliation years
Rate Base⁽¹⁾	\$8,831 million – Filing year (represents projected year-end rate base using 2015 actual plus 2016 projected capital additions). 2016 and 2017 earnings will reflect 2016 and 2017 year-end rate base respectively. \$7,781 million - Reconciliation year (represents year-end rate base for 2015)
Revenue Requirement Increase⁽¹⁾	\$132M increase (\$4M decrease due to the 2015 reconciliation and collar adjustment offset by a \$136M increase related to the filing year). The 2015 reconciliation impact on net income was recorded in 2015 as a regulatory asset.
Timeline	<ul style="list-style-type: none"> • 04/13/16 Filing Date • 240 Day Proceeding

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⁾ Amounts represent ComEd's position filed in surrebuttal testimony on August 19, 2016

Note: Disallowance of any items in the 2016 distribution formula rate filing could impact 2016 earnings in the form of a regulatory asset adjustment

Pepco MD Electric Distribution Rate Case

Case No.	9418
Test Year	2015 Calendar Year
Test Period	12 months actual
Requested Common Equity Ratio	49.6%
Requested Rate of Return	ROE: 10.60%; ROR: 8.01%
Proposed Rate Base (Adjusted)	\$1.7B
Requested Revenue Requirement Increase (Updated on September 8, 2016)	\$102.8M ⁽¹⁾
Residential Total Bill % Increase	8.71%
Notes	<ul style="list-style-type: none"> • 4/19/16 Pepco MD filed application with the MDPSC seeking increase in electric distribution base rates • Size of ask is driven by 2 years of capital investment, recovery of AMI investments and new depreciation rates • 12 month forward looking reliability and other plant additions from January 2016 through December 2016 (\$17.9M of Revenue Requirement based on a 10.60% ROE) included in revenue requirement request • Extension of the Grid Resiliency Program to fund accelerated investments in grid resiliency, incremental to the capital plan (not included in revenue requirement request) <ul style="list-style-type: none"> • Capital \$31.6 million (Feeder Work \$24.0 million and Reclosing Devices \$7.6 million) in 2017-2018 <p>Procedural Schedule:</p> <ul style="list-style-type: none"> • Evidentiary Hearings Completed (9/13/16 – 9/23/16) • Final Reply Briefs: 10/26/16 • Commission Order Expected: 11/15/16 • New rates are in effect shortly after the final order

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

DPL DE (Electric) Distribution Rate Case

Docket #	16-0649
Test Year	2015 Calendar Year
Test Period	12 months actual
Requested Common Equity Ratio	49.4%
Requested Rate of Return	ROE: 10.60%; ROR: 7.19%
Proposed Rate Base (Adjusted)	\$846M
Requested Revenue Requirement Increase	\$62.8M ⁽¹⁾⁽²⁾
Residential Total Bill % Increase	7.25%
Notes	<ul style="list-style-type: none"> • 5/17/16 DPL DE filed application with the DPSC seeking increase in electric distribution base rates • 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 • 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 <p>Procedural Schedule:</p> <ul style="list-style-type: none"> • Evidentiary Hearings: 3/7/17 – 3/9/17 • Commission Order Expected: Q3 2017

(1) As permitted by Delaware law, Delmarva Power implemented interim rate increases of \$2.5 million on July 16, 2016 and will implement full allowable rates 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

DPL DE (Gas) Distribution Rate Case

Docket #	16-0650
Test Year	2015 Calendar Year
Test Period	12 months actual
Requested Common Equity Ratio	49.4%
Requested Rate of Return	ROE: 10.60%; ROR: 7.19%
Proposed Rate Base (Adjusted)	\$362M
Requested Revenue Requirement Increase	\$21.5M ⁽¹⁾⁽²⁾
Residential Total Bill % Increase	10.40%
Notes	<ul style="list-style-type: none"> • 5/17/16 DPL DE filed application with the DPSC seeking increase in gas distribution base rates • 18 month forward looking reliability and other plant additions from January 2016 through June 2017 (\$3.4M of Revenue Requirement based on 10.60% ROE) included in revenue requirement request <p>Procedural Schedule:</p> <ul style="list-style-type: none"> • Evidentiary Hearings: 4/5/17 – 4/7/17 • Commission Order Expected: Q3 2017

(1) As permitted by Delaware law, Delmarva Power implemented interim rate increases of \$2.5 million on July 16, 2016 and will implement full allowable rates 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

Formal Case No.	1139
Test Year	April 1, 2015 – March 31, 2016
Test Period	12 months actual
Requested Common Equity Ratio	49.14%
Requested Rate of Return	ROE: 10.60%; ROR: 8.00%
Proposed Rate Base (Adjusted)	\$1.7B
Requested Revenue Requirement Increase (Updated on October 14, 2016)	\$82.1M ⁽¹⁾
Residential Total Bill % Increase	5.15% ⁽²⁾
Notes	<ul style="list-style-type: none"> • 6/30/16 Pepco DC filed application with the DCPSC seeking increase in electric distribution base rates • Size of ask is driven by 3 years of capital investments • 18 month forward looking reliability and other plant additions from April 2016 through September 2017 (\$26.7M of Revenue Requirement based on 10.60% ROE) included in revenue requirement request • The Merger Order provides for a Customer Base Rate Credit (CBRC) in the amount of \$25.6M, which can be used to offset rate increases approved by the DCPSC; the parties will be provided an opportunity to propose how the CRBC and Incremental Offset be allocated and over what period of time <ul style="list-style-type: none"> • The DCPSC will ultimately decide how to allocate the CBRC <p>Procedural Schedule:</p> <ul style="list-style-type: none"> • Evidentiary Hearings: 3/15/17 – 3/21/17 • Final Briefs: 4/24/17 • Commission Order Expected: 7/25/17

(1) Revenue requirement includes changes in amortization expense, which has 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 5.25% total bill increase for a residential customer.

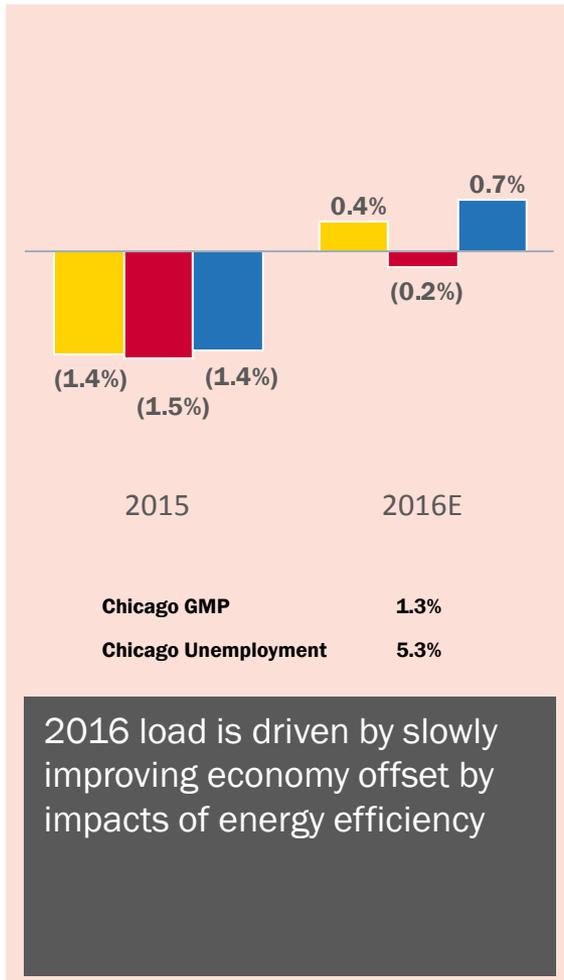
DPL MD Distribution Rate Case

Case No.	9424
Test Year	April 1, 2015 – March 31, 2016
Test Period	12 months actual
Requested Common Equity Ratio	49.1%
Requested Rate of Return	ROE: 10.60%; ROR: 7.24%
Proposed Rate Base	\$727M
Requested Revenue Requirement Increase (Updated on October 18, 2016)	\$57.0M ⁽¹⁾
Residential Total Bill % Increase	12.5%
Notes	<ul style="list-style-type: none"> • 7/20/16 DPL MD filed application with the MDPSC seeking increase in electric distribution base rates • Size of ask is driven by 3 years of capital investment, recovery of AMI investments and new depreciation rates • Extension of the Grid Resiliency Program to fund accelerated investments in grid resiliency, incremental to the capital plan (not included in revenue requirement request) Capital \$9.2 million (Feeder Work \$4.2 million and Reclosing Devices \$5.0 million) in 2017-2018 • 10 month forward looking reliability and other plant additions from April 2016 through January 2017 (\$5.0M of Revenue Requirement based on 10.60% ROE) included in revenue requirement request <p>Procedural Schedule:</p> <ul style="list-style-type: none"> • Evidentiary Hearings: 11/2/16 – 11/10/16 • Final Briefs: 12/14/16 • Commission Order Expected: 2/17/17 • New rates are in effect shortly after the final order

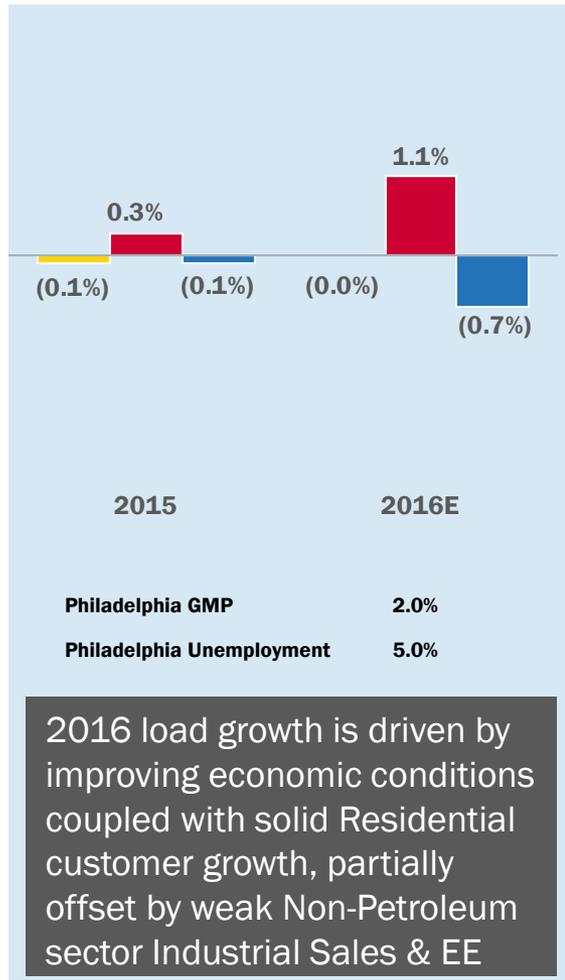
(1) Revenue requirement includes changes in depreciation and amortization expense, which have no impact on pre-tax earnings

■ All Customers
 ■ Residential
 ■ Commercial & Industrial

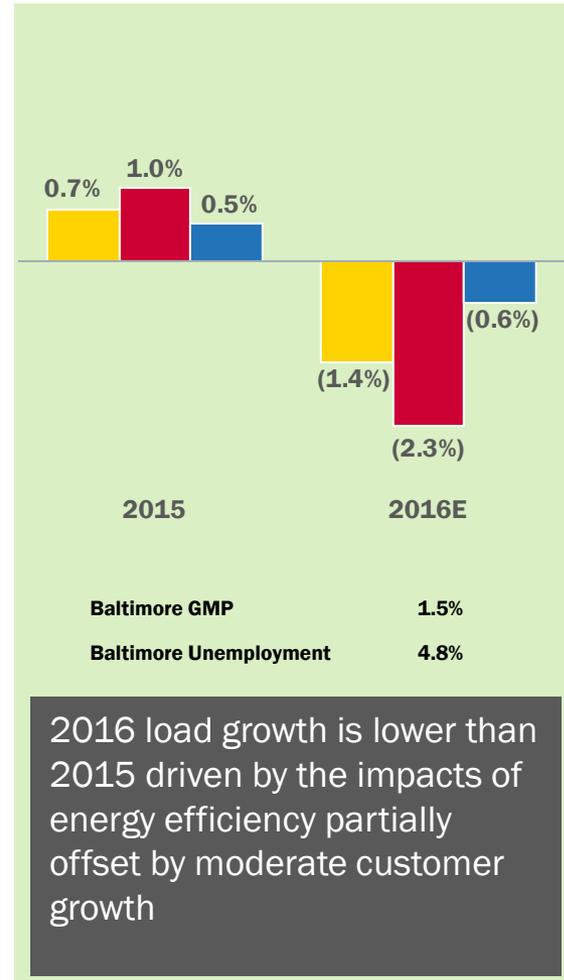
ComEd



PECO



BGE

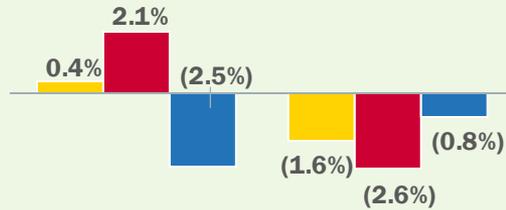


Notes: Data is weather normalized and not adjusted for leap year. Source of economic outlook data is IHS and US Department of Labor (September 2016) . Assumes 2016 U.S. GDP of 1.5% and U.S. unemployment of 5.0%. ComEd has the ROE collar as part of the distribution formula rate and BGE is decoupled which mitigates the load risk. QTD and YTD actual data can be found in earnings release tables. BGE amounts have been adjusted for prior quarter true-ups.

Exelon Utilities Load (cont'd)

■ All Customers
 ■ Residential
 ■ Commercial & Industrial

ACE



2015

2016E

ACE GMP

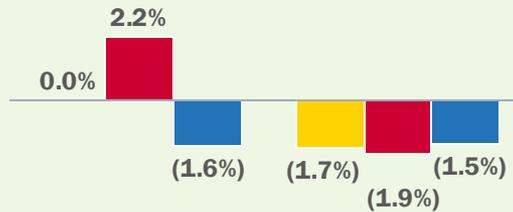
0.4%

ACE Unemployment

8.0%

2016 load is driven by the impacts of energy efficiency and distributed generation, partially offset by modest customer growth driven by improvements in economic conditions

Delmarva



2015

2016E

DPL GMP

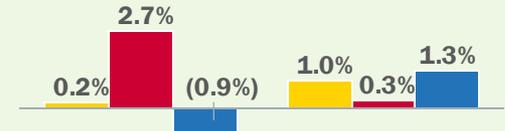
3.6%

DPL Unemployment

5.0%

2016 load is driven by the impacts of lower usage at significant industrial customers and energy efficiency partially offset by improved employment and customer growth

Pepco



2015

2016E

Pepco GMP

1.2%

Pepco Unemployment

4.8%

2016 load is driven by stronger commercial usage and residential customer growth partially offset by the impacts of energy efficiency and distributed generation

~65% of 2016 forecast distribution revenue is decoupled for PHI

Notes: Data is weather normalized using 20-year historical average and not adjusted for leap year. Source of economic outlook data is IHS (September 2016). Assumes 2016 GDP of 1.5% and U.S. unemployment rate of 5.0%. Pepco and DPL MD are decoupled which mitigates the load risk. QTD and YTD actual data can be found in earnings release tables. ACE includes Atlantic City, Vineland and Ocean City MSAs (Metropolitan Statistical Area). DPL MSA includes Wilmington Division, Dover MSA and Salisbury MSA. Pepco MSA includes the city of Washington DC and Silver Spring/Frederick Division. Pepco reclassified certain customer classes in DC from C&I to Residential in 2015. Including the impacts of the re-class, 2015 Residential load growth would have been 6.7% and C&I load growth would have been (2.7%).

Appendix

Reconciliation of Non-GAAP Measures

3Q QTD GAAP EPS Reconciliation

Three Months Ended September 30, 2015	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
2015 GAAP Earnings (Loss) Per Share	\$0.41	\$0.17	\$0.10	\$0.06	\$0.00	\$(0.04)	\$0.69
Mark-to-market impact of economic hedging activities	0.09	-	-	-	-	-	0.09
Unrealized losses related to NDT fund investments	0.15	-	-	-	-	-	0.15
Amortization of commodity contract intangibles	-	-	-	-	-	-	-
Merger and integration costs	0.02	-	-	-	-	-	0.02
Asset retirement obligation	(0.01)	-	-	-	-	-	(0.01)
Tax settlements	(0.06)	-	-	-	-	-	(0.06)
CENG non-controlling interest	(0.05)	-	-	-	-	-	(0.05)
2015 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$0.55	\$0.17	\$0.10	\$0.06	\$0.00	\$(0.04)	\$0.83

Three Months Ended September 30, 2016	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
2016 GAAP Earnings (Loss) Per Share	\$0.25	\$0.04	\$0.13	\$0.06	\$0.18	\$(0.13)	\$0.53
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 non-controlling interest	0.03	-	-	-	-	-	0.03
2016 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$0.41	\$0.20	\$0.13	\$0.06	\$0.14	\$(0.03)	\$0.91

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

3Q YTD GAAP EPS Reconciliation

Nine Months Ended September 30, 2015	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
2015 GAAP Earnings (Loss) Per Share	\$1.38	\$0.38	\$0.34	\$0.23	-	\$(0.11)	\$2.22
Mark-to-market impact of economic hedging activities	(0.18)	-	-	-	-	-	(0.18)
Unrealized losses related to NDT fund investments	0.19	-	-	-	-	-	0.19
Amortization of commodity contract intangibles	(0.01)	-	-	-	-	-	(0.01)
Merger and integration costs	0.02	0.01	-	-	-	0.03	0.06
Long-lived asset impairments	-	-	-	-	-	0.02	0.02
Asset retirement obligation	(0.01)	-	-	-	-	-	(0.01)
Tax settlements	(0.06)	-	-	-	-	-	(0.06)
Mark-to-market impact of PHI merger related interest rate swap	-	-	-	-	-	(0.03)	(0.03)
Midwest Generation bankruptcy recoveries	(0.01)	-	-	-	-	-	(0.01)
CENG non-controlling interest	(0.06)	-	-	-	-	-	(0.06)
2015 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$1.26	\$0.39	\$0.34	\$0.23	-	\$(0.09)	\$2.13

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

3Q YTD GAAP EPS Reconciliation (continued)

<u>Nine Months Ended September 30, 2016</u>	<u>ExGen</u>	<u>ComEd</u>	<u>PECO</u>	<u>BGE</u>	<u>PHI</u>	<u>Other</u>	<u>Exelon</u>
2016 GAAP Earnings (Loss) Per Share	\$0.58	\$0.32	\$0.37	\$0.20	(\$0.10)	(\$0.37)	\$1.00
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 non-controlling interest	0.04	-	-	-	-	-	0.04
2016 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$1.10	\$0.48	\$0.37	\$0.20	\$0.20	(\$0.11)	\$2.24

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

- **Exelon's Q3 2016 adjusted (non-GAAP) operating earnings excludes the earnings effects of the following:**
 - Mark-to-market adjustments from economic hedging activities
 - Unrealized gains and losses from NDT fund investments to the extent not offset by contractual accounting as described in the notes to the consolidated financial statements
 - Non-cash amortization of intangible assets, net, related to commodity contracts recorded at fair value at the date of acquisition of Integrys in 2014 and ConEdison Solutions in 2016
 - Certain costs incurred associated with PHI and FitzPatrick acquisitions
 - Adjustments to merger commitments costs related to settlement of PHI acquisition
 - Impairments of upstream assets
 - Plant retirements and divestitures at Generation
 - Costs incurred related to cost management program
 - Like-kind exchange tax position at Exelon and ComEd
 - Generation's non-controlling interest related to CENG exclusion items
 - Other unusual items

GAAP to Non-GAAP Reconciliations

2016 Adjusted Cash from Ops Calculation (\$M) ⁽¹⁾	ComEd	PECO	BGE	PHI	ExGen	Other	Exelon
Net cash flows provided by operating activities (GAAP)	\$1,875	\$775	\$700	\$800	\$4,100	(\$875)	\$7,375
Other cash from investing activities	-	-	-	(\$25)	(\$125)	-	(\$150)
Intercompany receivable adjustment	(\$350)	-	-	-	-	\$350	-
Counterparty collateral activity	-	-	-	-	(\$375)		(\$375)
Adjusted Cash Flow from Operations	\$1,525	\$775	\$700	\$775	\$3,600	(\$525)	\$6,850

2016 Cash From Financing Calculation (\$M) ⁽¹⁾	ComEd	PECO	BGE	PHI	ExGen	Other	Exelon
Net cash flow provided by financing activities (GAAP)	\$675	(\$250)	\$175	\$25	(\$350)	\$2,250	\$2,525
Dividends paid on common stock	\$375	\$275	\$175	\$250	\$925	(\$825)	\$1,175
Intercompany receivable adjustment	\$350	-	-	-	-	(\$350)	
Purchase of PHI (including cash acquired)	-	-	-	-	-	(\$6,925)	(\$6,925)
Financing Cash Flow	\$1,400	\$25	\$350	\$275	\$575	(\$5,850)	(\$3,225)

Exelon Total Cash Flow Reconciliation ⁽¹⁾	2016
GAAP Beginning Cash Balance	\$6,800
Adjustment for Cash Collateral Posted	\$1,300
Adjusted Beginning Cash Balance ⁽³⁾	\$8,100
Net Change in Cash (GAAP) ⁽²⁾	\$(6,600)
Adjusted Ending Cash Balance ⁽³⁾	\$1,500
Adjustment for Cash Collateral Posted	(\$900)
GAAP Ending Cash Balance	\$600

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

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

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

GAAP to Non-GAAP Reconciliations

ExGen Adjusted O&M Reconciliation (\$M) ⁽¹⁾	2016	2017	2018	2019
GAAP O&M	\$5,775	\$5,225	\$5,000	\$4,975
Decommissioning ⁽²⁾	125	200	125	50
Costs associated with early nuclear plant retirements	(150)	-	-	-
Long-lived asset impairment costs	(175)	-	-	-
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses ⁽³⁾	(450)	(400)	(425)	(425)
O&M for managed plants that are partially owned	(400)	(425)	(425)	(425)
Other	(175)	(25)	(25)	-
Adjusted O&M (Non-GAAP)	\$4,550	\$4,575	\$4,250	\$4,175

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

(2) Reflects earnings neutral O&M

(3) Reflects the direct cost of sales of certain businesses, which are included in Total Gross Margin, a non-GAAP measure