Earnings Conference Call
Second Quarter 2019

August 1, 2019

Cautionary Statements Regarding Forward-Looking Information

This presentation contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by Exelon Corporation, Exelon Generation Company, LLC, Commonwealth Edison Company, PECO Energy Company, Baltimore Gas and Electric Company, Pepco Holdings LLC, Potomac Electric Power Company, Delmarva Power & Light Company, and Atlantic City Electric Company (Registrants) include those factors discussed herein, as well as the items discussed in (1) Exelon's 2018 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 22, Commitments and Contingencies; (2) Exelon's Second Quarter 2019 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 16; and (3) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this press release. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this presentation.

Non-GAAP Financial Measures

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

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

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

Non-GAAP Financial Measures Continued

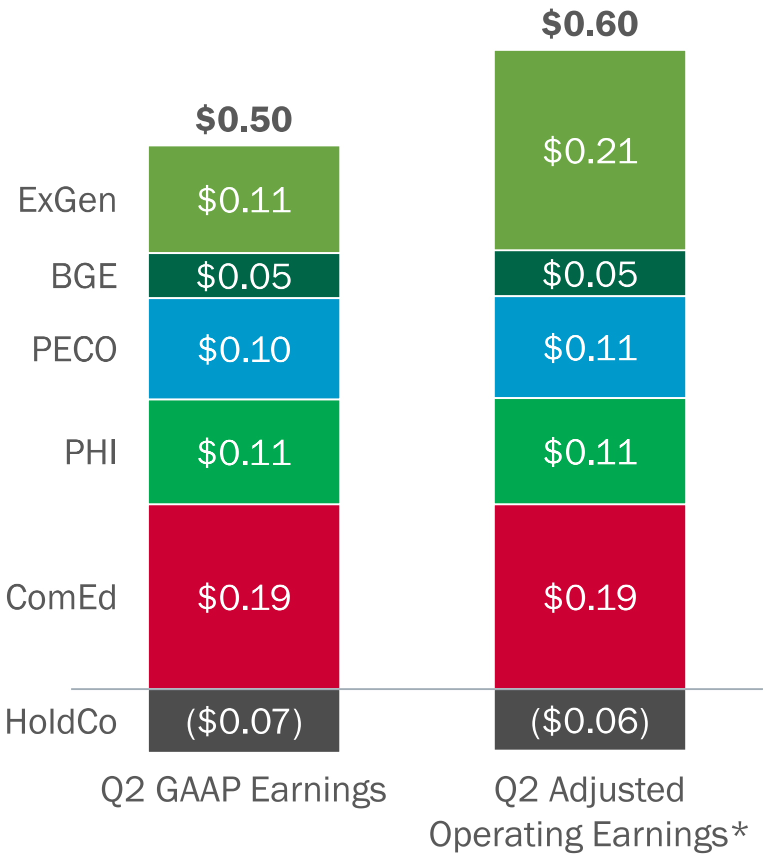
This information is intended to enhance an investor's overall understanding of period over period financial results and provide an indication of Exelon's baseline operating performance by excluding items that are considered by management to be not directly related to the ongoing operations of the business.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

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

Non-GAAP financial measures are identified by the phrase "non-GAAP" or an asterisk (*). Reconciliations of these non-GAAP measures to the most comparable GAAP measures are provided in the appendices and attachments to this presentation, except for the reconciliation for total gross margin, which appears on slide 32 of this presentation.

Second Quarter Results

Q2 2019 EPS Results[1]



- GAAP earnings were $0.50/share in Q2 2019 vs. $0.56/share in Q2 2018
- Adjusted operating earnings* were $0.60/share in Q2 2019 vs. $0.71/share in Q2 2018, which was at the midpoint of our guidance range of $0.55-$0.65/share

(1) Amounts may not sum due to rounding

Operating Highlights

Exelon Utilities Operational Metrics

Operations	Metric	YTD 2019			
		BGE	ComEd	PECO	PHI
Electric Operations	OSHA Recordable Rate				
	2.5 Beta SAIFI (Outage Frequency)(1)				
	2.5 Beta CAIDI (Outage Duration)				
Customer Operations	Customer Satisfaction				
	Service Level % of Calls Answered in <30 sec				
	Abandon Rate				
Gas Operations	Gas Odor Response		No Gas Operations		

- Strong reliability metrics across our utilities with ComEd in the top decile performance in both CAIDI and SAIFI
- Each utility continued to deliver on key customer operations metrics:
  - ComEd and PHI achieved top decile performance in Service Level and Abandon Rate
  - BGE, ComEd and PECO recorded top decile performance in Customer Satisfaction
  - Delmarva Power achieved the number one ranking in J.D. Power's 2019 Electric Utility Residential Customer Satisfaction Study for the East Midsize Region; first Exelon utility to rank first

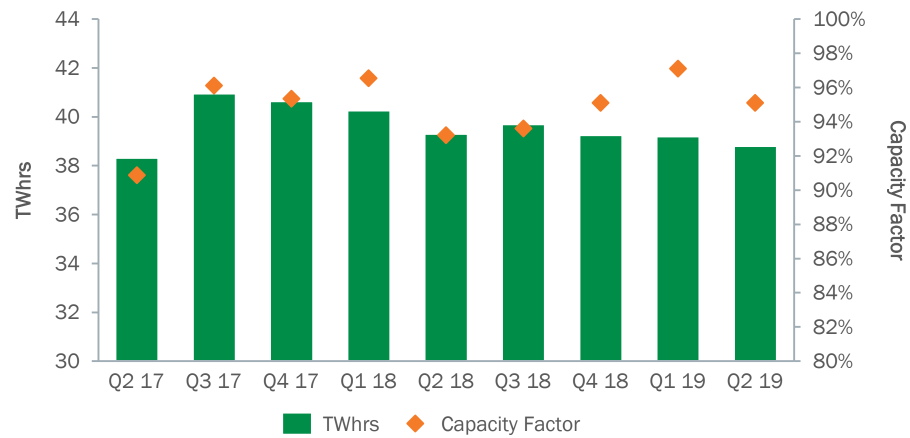
Quartile

Q1	Q2
Q3	Q4

Exelon Generation Operational Performance

Exelon Nuclear Fleet(2)

- Best in class performance across our Nuclear fleet:
  - Q2 2019 Nuclear Capacity Factor: 95.1%
  - Owned and operated Q2 2019 production of 38.8 TWh



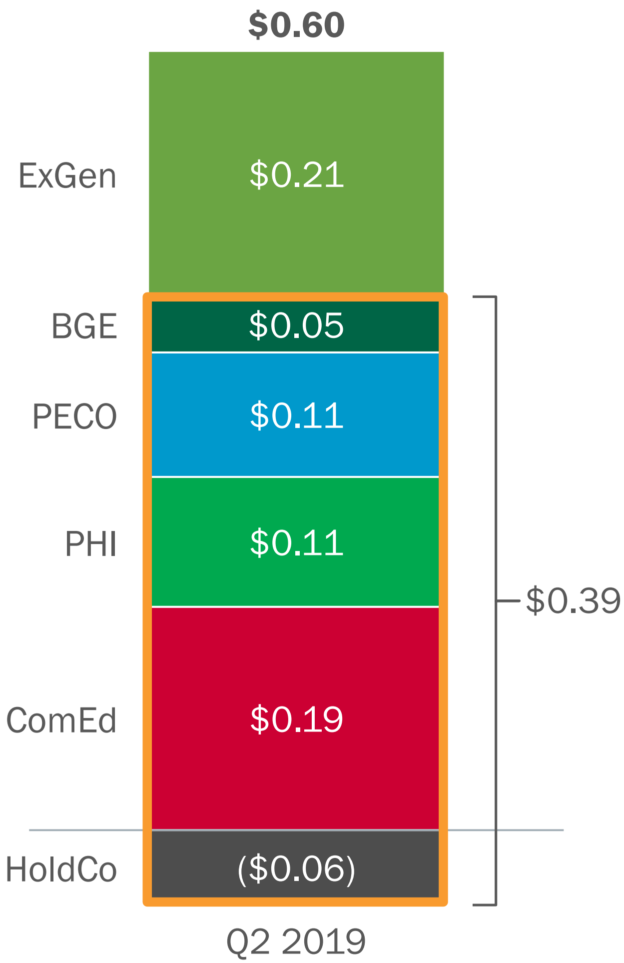
Fossil and Renewable Fleet

- Q2 2019 Renewables Energy Capture: 96.0%
- Q2 2019 Power Dispatch Match: 99.7%

(1) 2.5 Beta SAIFI is YE projection
(2) Excludes Salem and EDF's equity ownership share of the CENG Joint Venture

Second Quarter Adjusted Operating Earnings* Drivers

Q2 2019 Adjusted Operating EPS* Results



Q2 2019 vs. Guidance of $0.55 - $0.65

- Adjusted (non-GAAP) operating earnings drivers versus guidance:

Exelon Utilities

- ↑ Timing of O&M
- ↓ Unfavorable weather

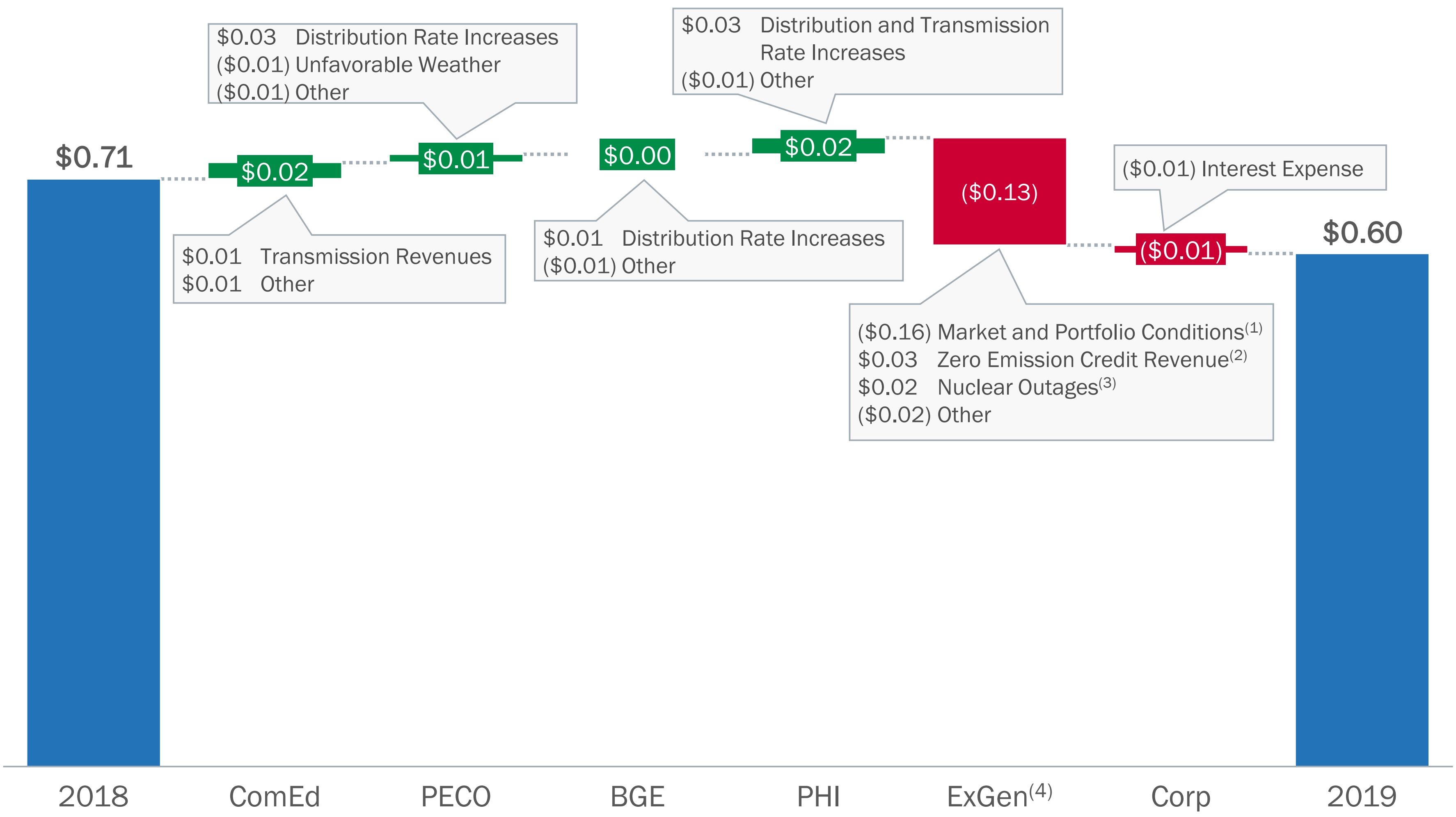
Exelon Generation

- ↓ Lower load volumes
- ↓ Salem outage
- ↑ NDT realized gains(1)
- ↑ Timing of O&M

Expect Q3 2019 Adjusted Operating Earnings* of $0.80 - $0.90 per share

Note: Amounts may not sum due to rounding
(1) Gains related to unregulated sites

Q2 2019 QTD Adjusted Operating Earnings* Waterfall



Note: Amounts may not sum due to rounding

(1) Primarily reflects lower realized energy prices

(2) Primarily reflects an increase in New York ZEC prices and the approval of the New Jersey ZEC Program in the second quarter of 2019

(3) Reflects a decrease in nuclear outage days in 2019, excluding Salem, partially offset by an increase in nuclear outage days at Salem in 2019

(4) Drivers reflect CENG ownership at 100%

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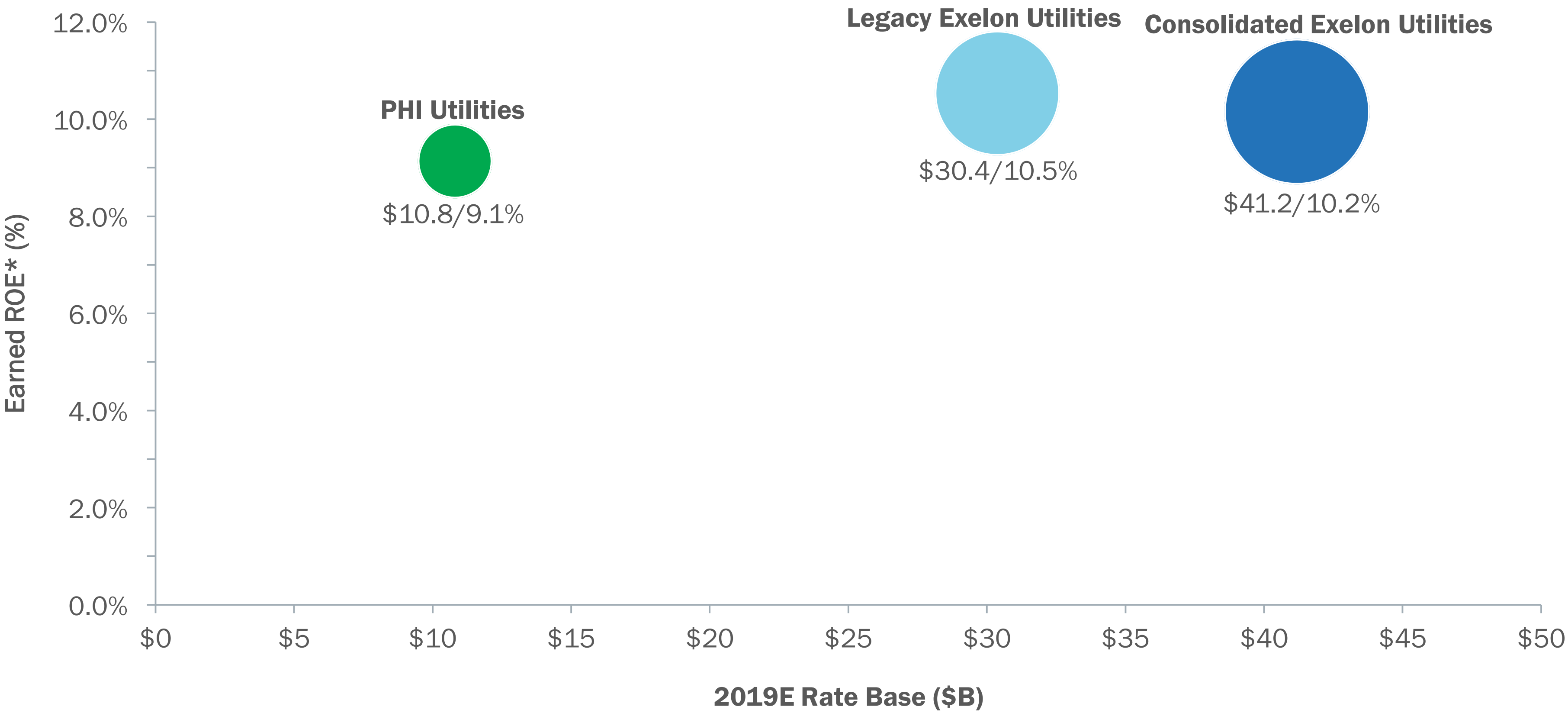
Exelon Utilities Trailing Twelve Month Earned ROEs*

Q2 2019: Trailing Twelve Month Earned ROEs*



TTM ROEs*	PHI Utilities	Legacy Exelon Utilities	Consolidated Exelon Utilities
Q2 2019	9.1%	10.5%	10.2%
Q1 2019	9.3%	10.5%	10.2%

Note: Represents the twelve-month period ending June 30, 2019 and March 31, 2019. Earned ROEs* represent weighted average across all lines of business (Electric Distribution, Gas Distribution, and Electric Transmission). Size of bubble based on rate base.

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Exelon Utilities' Distribution Rate Case Updates

Rate Case Schedule and Key Terms

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Revenue Requirement	Requested ROE / Equity Ratio	Expected Order
Pepco MD Electric	IT RT	EH	IB		FO								$10.3M[1,6]	9.60%[6] / 50.46%	Aug 13, 2019
ComEd	CF		IT	RT	EH	IB RB			FO				($6.4M)[1,2]	8.91% / 47.97%	Dec 4, 2019
BGE		CF				IT	RT EH	IB RB	FO				$148.7M[1,3]	10.3% / 52.1%	Dec 20, 2019
Pepco DC[4] Electric		CF			IT		RT		EH	IB RB			$162.0M[1,5] 3-Year MYP	10.30% / 50.46%	May 1, 2020

- CF Rate case filed
- IT Intervenor direct testimony
- RT Rebuttal testimony
- EH Evidentiary hearings
- IB Initial briefs
- RB Reply briefs
- FO Final commission order
- SA Settlement agreement

Note: Unless otherwise noted, based on schedules of Illinois Commerce Commission, Maryland Public Service Commission, Pennsylvania Public Utility Commission, Delaware Public Service Commission, Public Service Commission of the District of Columbia, and New Jersey Board of Public Utilities that are subject to change

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

(2) Through the discovery period in the current proceeding, ComEd agreed to ~($9M) in adjustments

(3) Reflects $81.1M increase for electric and $67.6M increase for gas. Increase reflects $8.7M of STRIDE (gas) and $7.1M of ERI (electric) that will be transferred from the STRIDE and ERI surcharges to base rates.

(4) Procedural schedule as proposed by the Company in its initial application; Commission has not yet adopted a procedural schedule.

(5) Reflects 3-year cumulative multi-year plan. Company proposed incremental revenue requirement increases of $85M, $40M and $37M with rates effective May 1, 2020, January 1, 2021 and January 1, 2022, respectively.

(6) Reflects Chief Public Utility Law Judge (CPULJ) recommendation received on July 9

Featured Utility Capital Investments

DC Power Line Undergrounding (DC PLUG) Pepco Partnership

- **Forecasted project cost:**
  - Total project cost of $500 million to be shared equally with District Department of Transportation (DDOT)
- **In service date:**
  - Multiple in service dates contingent on DC PSC approval of biennial filings scheduled through 2021
  - DC PLUG initiative broke ground on June 14, 2019
- **Project scope:**
  - Partnership with DDOT focused on the underground placement of vulnerable distribution power lines
  - Up to 30 distribution voltage feeders to be installed underground
  - Improves grid resiliency and reliability by reducing risk of power outages caused by storms and supports faster restoration of customer interruptions

ComEd's Substation Expansion to Meet Data Center Growth

- **Forecasted project cost:**
  - $48.5 million
- **In service date:**
  - Project completed as of May 2019
- **Project scope:**
  - Installed a new distribution terminal and associated equipment, including an indoor switchgear building, three medium power transformers and twelve 138kV circuit breakers
  - The expanded substation provides capacity to power the equivalent of 45,000 homes and will support three new data centers in the Itasca/Elk Grove technology corridor near O'Hare airport
  - Enhances system reliability and resiliency by protecting equipment from weather and wildlife, while also allowing for further digitization of existing technologies

Exelon Generation: Gross Margin Update

Gross Margin Category ($M)[1]	June 30, 2019 2019	June 30, 2019 2020	June 30, 2019 2021	Change from March 31, 2019 2019	Change from March 31, 2019 2020	Change from March 31, 2019 2021
Open Gross Margin[2,5] (including South, West, New England, Canada hedged gross margin)	$3,600	$3,550	$3,300	$(600)	$(550)	$(500)
Capacity and ZEC Revenues[2,5]	$2,050	$1,900	$1,850	-	-	-
Mark-to-Market of Hedges[2,3]	$1,250	$750	$400	$700	$500	$300
Power New Business / To Go	$250	$600	$800	$(100)	$(50)	$(50)
Non-Power Margins Executed	$350	$200	$150	$50	$50	-
Non-Power New Business / To Go	$150	$300	$400	$(50)	$(50)	-
Total Gross Margin*[4,5]	**$7,650**	**$7,300**	**$6,900**	**-**	**$(100)**	**$(250)**

Recent Developments

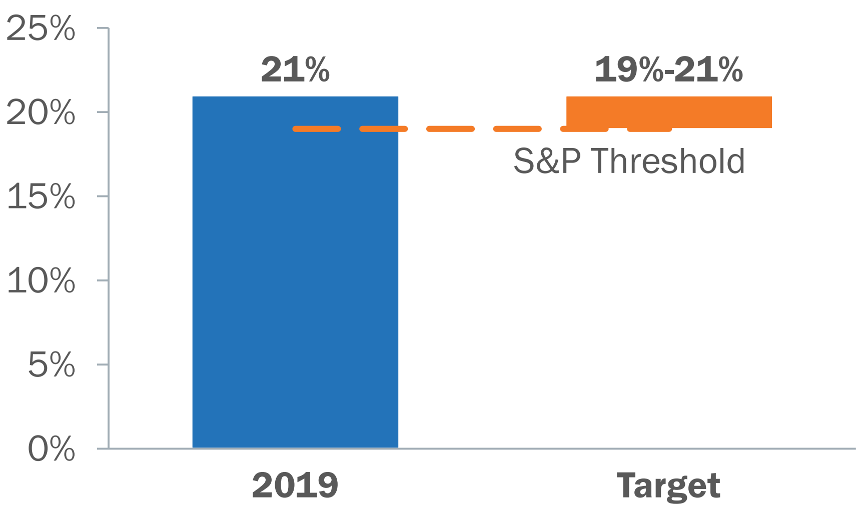
- 2019 Total Gross Margin* is flat due to declining power prices offset by our hedges and execution of a combined $150M of power and non-power new business
- 2020 and 2021 Total Gross Margins* are down $100M and $250M, respectively, due to lower energy prices
- Behind ratable hedging position reflects the fundamental upside we see in power prices
  - ~10-13% behind ratable in 2020 when considering cross commodity hedges
  - ~7-10% behind ratable in 2021 when considering cross commodity hedges

(1) Gross margin categories rounded to nearest $50M
(2) Excludes EDF's equity ownership share of the CENG Joint Venture
(3) Mark-to-Market of Hedges assumes mid-point of hedge percentages
(4) Based on June 30, 2019 market conditions
(5) Reflects TMI retirement in September 2019

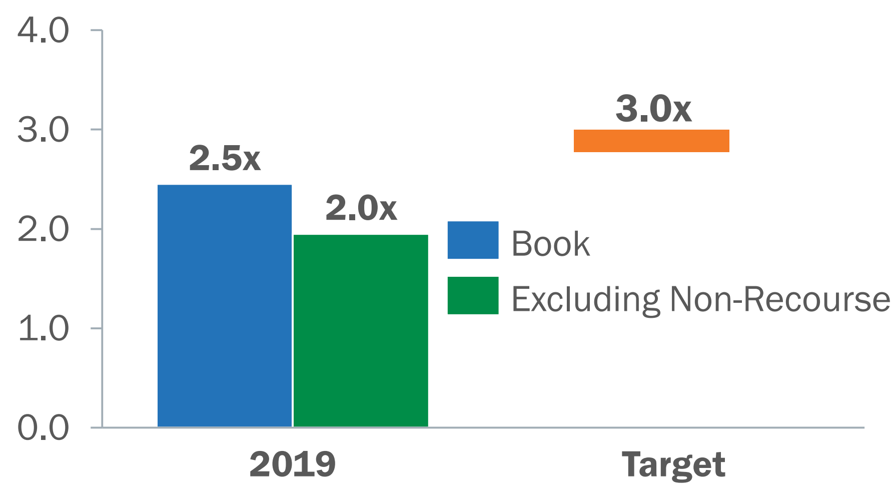
Exelon

Maintaining Strong Investment Grade Credit Ratings is a Top Financial Priority

Exelon S&P FFO/Debt %*[1,4]



ExGen Debt/EBITDA Ratio*[5]



Credit Ratings by Operating Company

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

(1) Due to ring-fencing, S&P deconsolidates BGE from Exelon and analyzes solely as an equity investment
(2) Current senior unsecured ratings as of June 30, 2019, for Exelon, Exelon Generation and BGE and senior secured ratings for ComEd, PECO, ACE, DPL, and Pepco
(3) ACE was upgraded by Moody's from A3 to A2 in June 2019
(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 at Exelon Corp
(5) Reflects net book debt (YE debt less cash on hand) / adjusted operating EBITDA*

Exelon

The Exelon Value Proposition

- **Regulated Utility Growth** with utility EPS rising 6-8% annually from 2018-2022 and rate base growth of 7.8%, representing an expanding majority of earnings
- **ExGen's strong free cash generation** will provide ~$4.2B for utility growth and reduce debt by ~$2.5B 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 2022 planning horizon
- **Capital allocation priorities targeting**:
  - Organic utility growth;
  - Return of capital to shareholders with 5% annual dividend growth through 2020[1];
  - Debt reduction; and,
  - Modest contracted generation investments

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

Exelon.

Additional Disclosures

2019 Adjusted Operating Earnings* Guidance

Key Year-Over-Year Drivers

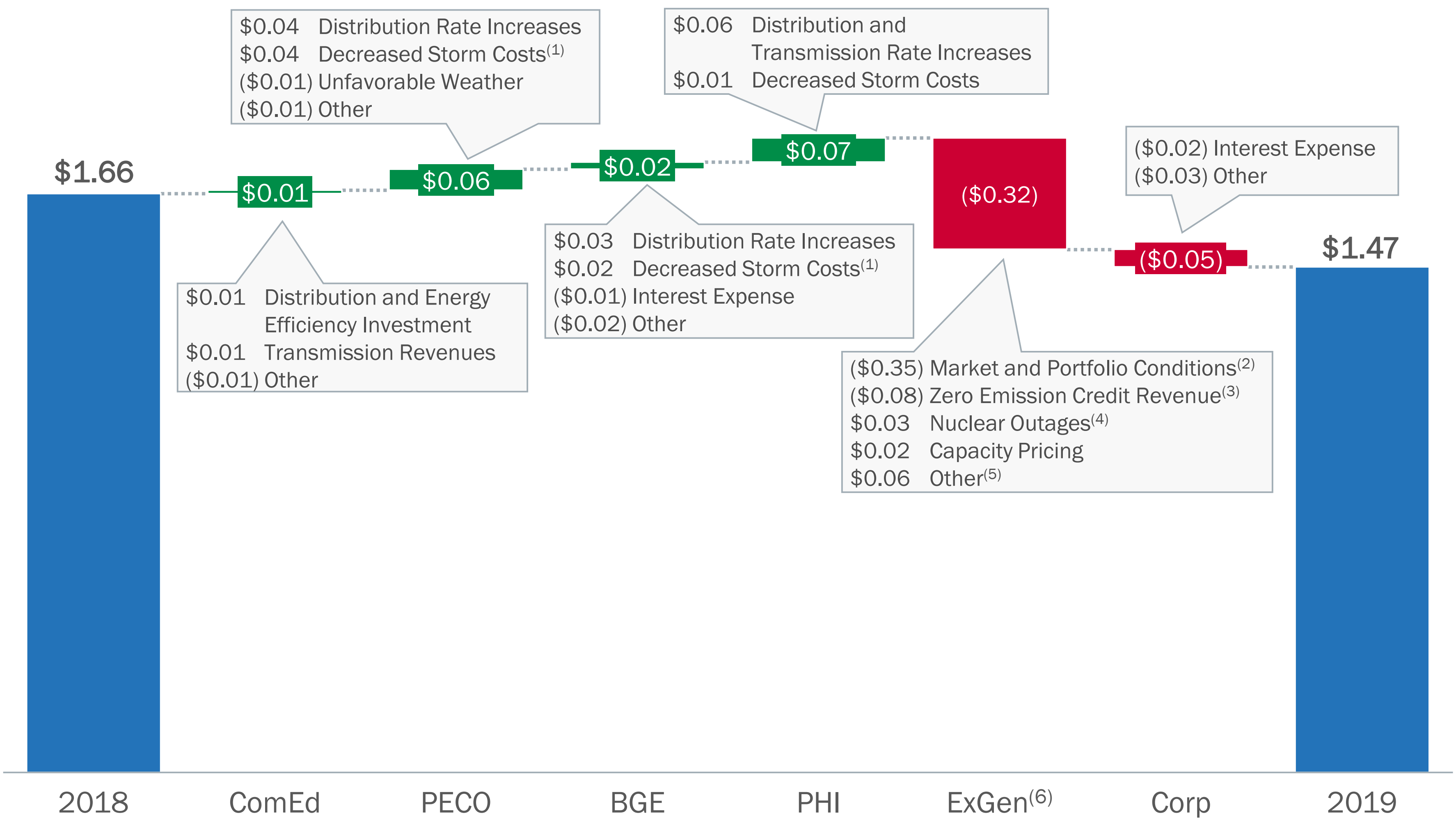
- **ExGen**: Lower realized energy prices and absence of IL ZEC timing, partially offset by NJ ZEC uplift
- **BGE**: Higher distribution and transmission revenue, partially offset by higher depreciation
- **PECO:** Higher distribution and transmission revenue, return to normal storm (historical average), partially offset by higher depreciation
- **PHI:** Higher distribution and transmission revenue and favorable O&M, partially offset by higher depreciation
- **ComEd**: Increased capital investments to improve reliability in distribution and transmission, partially offset by lower treasury rates

Note: Amounts may not add due to rounding

(1) 2018 results based on 2018 average outstanding shares of 969M

(2) 2019E earnings guidance based on expected average outstanding shares of 973M

Q2 2019 YTD Adjusted Operating Earnings* Waterfall



Note: Amounts may not sum due to rounding

(1) Primarily reflects the absence of the March 2018 winter storms

(2) Primarily reflects lower realized energy prices

(3) Primarily reflects the absence of revenue recognized in the first quarter 2018 related to zero emissions credits generated in Illinois from June through December 2017, partially offset by an increase in New York ZEC prices and the approval of the New Jersey ZEC Program in the second quarter of 2019

(4) Reflects a decrease in nuclear outage days in 2019, excluding Salem, partially offset by an increase in nuclear outage days at Salem in 2019

(5) Primarily reflects the elimination of activity attributable to noncontrolling interests, primarily for CENG

(6) Drivers reflect CENG ownership at 100%

Exelon

2019 Projected Sources and Uses of Cash

($M)[1]	BGE	ComEd	PECO	PHI	Total Utilities	ExGen	Corp[8]	Exelon	Cash Balance
Beginning Cash Balance[2]									**1,825**
Adjusted Cash Flow from Operations[2]	675	1,325	750	1,050	3,800	3,950	(275)	7,500	
Base CapEx and Nuclear Fuel[3]	-	-	-	-	-	(1,775)	(75)	(1,850)	
Free Cash Flow	**675**	**1,325**	**750**	**1,050**	**3,800**	**2,175**	**(325)**	**5,650**	
Debt Issuances	350	700	300	375	1,725	-	-	1,725	
Debt Retirements	-	(300)	-	-	(300)	(625)	-	(925)	
Project Financing	n/a	n/a	n/a	n/a	n/a	(100)	n/a	(100)	
Equity Issuance/Share Buyback	-	-	-	-	-	-	-	-	
Contribution from Parent	200	250	150	200	800	-	(800)	-	
Other Financing[4]	200	300	25	-	525	(125)	25	450	
Financing[5]	**750**	**950**	**500**	**575**	**2,775**	**(850)**	**(775)**	**1,150**	
Total Free Cash Flow and Financing	**1,425**	**2,250**	**1,250**	**1,625**	**6,575**	**1,325**	**(1,100)**	**6,800**	
Utility Investment	(1,200)	(1,875)	(1,000)	(1,400)	(5,450)	-	-	(5,450)	
ExGen Growth[3,6]	-	-	-	-	-	(150)	-	(150)	
Acquisitions and Divestitures	-	-	-	-	-	25	-	25	
Equity Investments	-	-	-	-	-	(25)	-	(25)	
Dividend[7]	-	-	-	-	-	-	-	(1,400)	
Other CapEx and Dividend	**(1,200)**	**(1,875)**	**(1,000)**	**(1,400)**	**(5,450)**	**(150)**	**-**	**(7,000)**	
Total Cash Flow	**250**	**375**	**250**	**250**	**1,125**	**1,200**	**(1,100)**	**(200)**	
Ending Cash Balance[2]									**1,625**

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

(2) Gross of posted counterparty collateral

(3) Figures reflect cash CapEx and CENG fleet at 100%

(4) Other Financing primarily includes expected changes in money pool, tax sharing from the parent, renewable JV distributions, tax equity cash flows, EDF Tax distributions and capital leases

(5) Financing cash flow* excludes intercompany dividends

(6) ExGen Growth CapEx primarily includes Retail Solar and W. Medway

(7) Dividends are subject to declaration by the Board of Directors

(8) Includes cash flow activity from Holding Company, eliminations and other corporate entities

Consistent and reliable free cash flows

Operational excellence and financial discipline drives free cash flow reliability*

- ✓ Generating $5,650M of free cash flow*, including $2,175M at ExGen and $3,800M at the Utilities

Supported by a strong balance sheet

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

- ✓ $1,425M of long-term debt at the utilities, net of refinancing, to support continued growth and retirement of $725M of ExGen debt

Enable growth & value creation

Creating value for customers, communities and shareholders

- ✓ Investing $5,600M of growth CapEx, with $5,450M at the Utilities and $150M at ExGen

Note: Numbers may not add due to rounding

Exelon Utilities

BGE Distribution Rate Case Filing

	Rate Case Filing Details
Docket No.	Case No. 9610
Test Year	August 1, 2018 – July 31, 2019
Test Period	8 months actual + 4 months estimated
Common Equity Ratio	52.1%(1)
Rate of Return	ROE: 10.3%; ROR: 7.25%(1)
Rate Base (Adjusted)	$5.4B
Revenue Requirement Increase	$148.7M(1)
Residential Total Bill % Increase	5.5%(2)

Notes

- Case filed on May 24, 2019 seeking an increase in electric and gas distribution revenues
- The increase is primarily driven by the ongoing need for capital investments to maintain and modernize the electric and gas distribution systems for the benefit of customers and includes moving revenues currently being recovered via the STRIDE and ERI Surcharges into Base Rates
- This Case also includes a depreciation study, which proposes an increase in depreciation expense of $45.4M based on updated depreciation rates primarily related to insufficient recoveries of actual cost of removal incurred
- The Commission is expected to issue an order on this case on December 20, 2019

Detailed Rate Case Schedule

	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr
Filed rate case	5/24/2019											
Intervenor testimony					9/10/2019							
Rebuttal testimony						10/4/2019						
Evidentiary hearings						10/25/2019 - 11/1/2019						
Initial briefs due(3)							11/15/2019					
Reply briefs due(3)							11/25/2019					
Commission order expected								12/20/2019				

(1) Reflects $81.1M increase for electric and $67.6M increase for gas. Increase reflects $8.7M of STRIDE (gas) and $7.1M of ERI (electric) that will be transferred from the STRIDE and ERI surcharges to base rates.
(2) Increase expressed as a percentage of a combined electric and gas residential customer total bill
(3) Initial Briefs are due two weeks after the end of the evidentiary hearings and Reply Briefs are due 10 days after Initial Briefs. Dates shown assume the evidentiary hearings end November 1, 2019.

Pepco DC (Electric) Distribution Rate Case Filing

Multi-Year Plan Case Filing Details	
Case No.	1156
Test Year	January 1 – December 31
Test Period	2020, 2021, 2022
Requested Common Equity Ratio	50.46%
Requested Rate of Return	ROE: 10.30%; ROR: 7.81%
2020-2022 Proposed Rate Base (Adjusted)	\$2.2B, \$2.4B, \$2.6B
2020-2022 Requested Revenue Requirement Increase(1)	\$85M, \$40M, \$37M
2020-2022 Residential Total Bill % Increase(1)	7.1%, 4.2%, 3.7%

Notes

- May 30, 2019, Pepco DC filed a three year multi-year plan (MYP) request with the Public Service Commission of the District of Columbia (DCPSC) seeking an increase in electric distribution base rates
- Size of ask is driven by continued investments in electric distribution system to maintain and increase reliability and customer service
- MYP proposes five Performance Incentive Mechanisms (PIMs) focused on system reliability, customer service and interconnection Distributed Energy Resources (DER)

Detailed Rate Case Schedule(2)

	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
Filed rate case	5/30/2019												
Intervenor testimony				8/16/2019									
Rebuttal testimony						10/4/2019							
Evidentiary hearings								12/16/2019 - 12/20/2019					
Initial briefs									1/16/2020				
Reply briefs									1/31/2020				
Commission order expected													5/1/2020

(1) Company proposed incremental revenue requirement increases with rates effective May 1, 2020, January 1, 2021 and January 1, 2022, respectively.
(2) Procedural schedule as proposed by the Company in its initial application; Commission has not yet adopted a procedural schedule.

Pepco MD (Electric) Distribution Rate Case Filing

	Rate Case Filing Details
Case No.	9602
Test Year	February 1, 2018 – January 31, 2019
Test Period	12 months actual
Recommended Common Equity Ratio(1)	50.46%
Recommended Rate of Return(1)	ROE: 9.60%; ROR: 7.45%
Recommended Rate Base (Adjusted)(1)	$2.0B
Recommended Revenue Requirement Increase(1)	$10.3M
Residential Total Bill % Increase(1)	1.40%

Notes

- Pepco MD filed an application with the Maryland Public Service Commission (MDPSC) on January 15, 2019, seeking an increase in electric distribution base rates
- Size of ask is driven by continued investments in electric distribution system to maintain and increase reliability and customer service
- On July 9, the CPULJ issued the proposed order with the final MDPSC order expected by August 13

Detailed Rate Case Schedule

	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov
Filed rate case		1/15/2019										
Intervenor testimony					4/12/2019							
Rebuttal testimony					4/30/2019							
Evidentiary hearings						5/21/2019 - 5/24/2019						
Initial briefs							6/17/2019					
Commission order expected									8/13/2019			

(1) Reflects Chief Public Utility Law Judge (CPULJ) recommendation received on July 9

ComEd Distribution Rate Case Filing

	Rate Case Filing Details
Docket No.	19-0387
Test Year	January 1, 2018 – December 31, 2018
Test Period	2018 Actual Costs + 2019 Projected Plant Additions
Requested Common Equity Ratio	47.97%
Requested Rate of Return	ROE: 8.91%; ROR: 6.53%
Proposed Rate Base (Adjusted)	$11,372M
Requested Revenue Requirement Increase	($6.4M)[1,2]
Residential Total Bill % Increase	(0.4%)

Notes

- April 8, 2019, ComEd filed its annual distribution formula rate update with the Illinois Commerce Commission seeking a decrease to distribution base rates

Detailed Rate Case Schedule[2]

	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb
Filed rate case		4/8/2019										
Intervenor testimony				6/20/2019								
Rebuttal testimony					7/17/2019							
Evidentiary hearings						8/29/2019						
Initial briefs							9/12/2019					
Reply briefs							9/26/2019					
Commission order expected										12/4/2019		

(1) Revenue requirement includes changes in depreciation and amortization expense and other costs where applicable, which have no impact on pre-tax earnings
(2) Through the discovery period in the current proceeding, ComEd agreed to ~($9M) in adjustments

Exelon Generation Disclosures

June 30, 2019

Portfolio Management Strategy

Strategic Policy Alignment

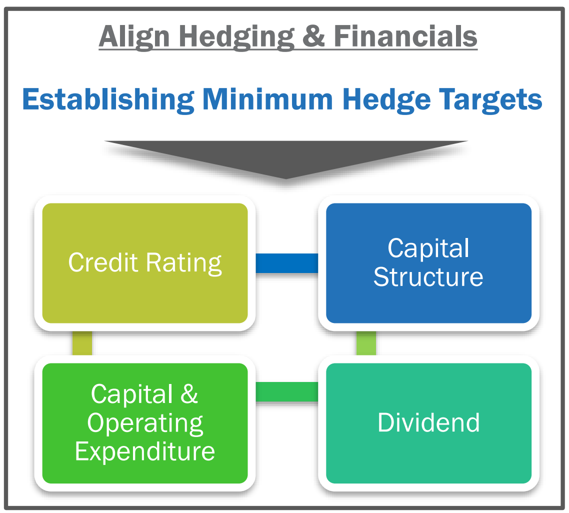
- Aligns hedging program with financial policies and financial outlook
  - Establish minimum hedge targets to meet financial objectives of the company (dividend, credit rating)
  - Hedge enough commodity risk to meet future cash requirements under a stress scenario

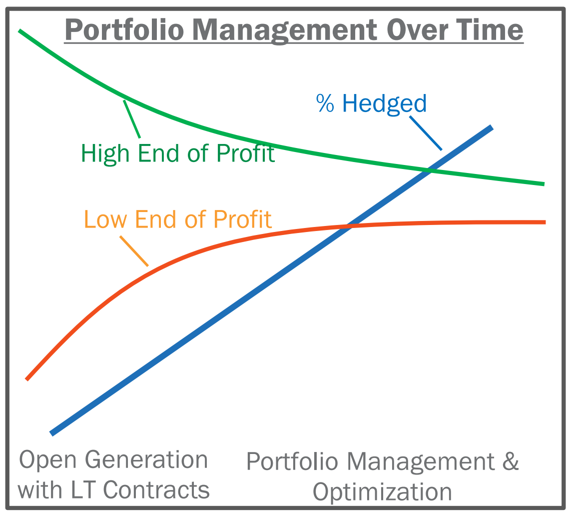
Three-Year Ratable Hedging

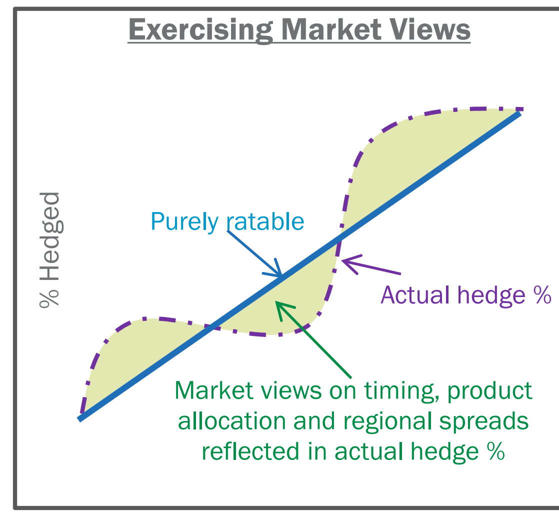
- Ensure stability in near-term cash flows and earnings
  - Disciplined approach to hedging
  - Tenor aligns with customer preferences and market liquidity
  - Multiple channels to market that allow us to maximize margins
  - Large open position in outer years to benefit from price upside

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**

Exelon.

Components of Gross Margin* Categories

Gross margin linked to power production and sales				Gross margin from other business activities	
Open Gross Margin	**Capacity and ZEC Revenues**	**MtM of Hedges[2]**	**"Power" New Business**	**"Non Power" Executed**	**"Non Power" New Business**
• Generation Gross Margin at current market prices, including ancillary revenues, nuclear fuel amortization and fuels expense • Power Purchase Agreement (PPA) Costs and Revenues • Provided at a consolidated level for all regions (includes hedged gross margin for South, West, New England and Canada[1])	• Expected capacity revenues for generation of electricity • Expected revenues from Zero Emissions Credits (ZEC)	• 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 four major regions. Provided indirectly for each of the four major regions via Effective Realized Energy Price (EREP), reference price, hedge %, expected generation.	• Retail, Wholesale planned electric sales • Portfolio Management new business • Mid marketing new business	• Retail, Wholesale executed gas sales • Energy Efficiency[4] • BGE Home[4] • Distributed Solar	• Retail, Wholesale planned gas sales • Energy Efficiency[4] • BGE Home[4] • Distributed Solar • Portfolio Management / origination fuels new business • Proprietary trading[3]

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

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

(1) Hedged gross margins for South, West, New England & 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 four 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, New England & Canada regions and optimization of fuel and PPA activities captured in Open Gross Margin

ExGen Disclosures

Gross Margin Category ($M)[1]	2019	2020	2021
Open Gross Margin (including South, West, New England & Canada hedged GM)[2,5]	$3,600	$3,550	$3,300
Capacity and ZEC Revenues[2,5]	$2,050	$1,900	$1,850
Mark-to-Market of Hedges[2,3]	$1,250	$750	$400
Power New Business / To Go	$250	$600	$800
Non-Power Margins Executed	$350	$200	$150
Non-Power New Business / To Go	$150	$300	$400
Total Gross Margin*[4,5]	**$7,650**	**$7,300**	**$6,900**

Reference Prices[4]	2019	2020	2021
Henry Hub Natural Gas ($/MMBtu)	$2.63	$2.54	$2.58
Midwest: NiHub ATC prices ($/MWh)	$23.63	$22.92	$22.22
Mid-Atlantic: PJM-W ATC prices ($/MWh)	$26.34	$27.63	$27.00
ERCOT-N ATC Spark Spread ($/MWh) *HSC Gas, 7.2HR, $2.50 VOM*	$7.35	$8.46	$6.72
New York: NY Zone A ($/MWh)	$28.10	$29.32	$29.05

(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 June 30, 2019 market conditions
(5) Reflects TMI retirement in September 2019

ExGen Disclosures

Generation and Hedges	2019	2020	2021
Exp. Gen (GWh)[1]	**189,800**	**185,300**	**181,200**
Midwest	97,600	96,500	95,600
Mid-Atlantic[2,6]	53,800	48,000	48,300
ERCOT	21,800	25,100	20,700
New York[2]	16,600	15,700	16,600
% of Expected Generation Hedged[3]	**92%-95%**	**70%-73%**	**40%-43%**
Midwest	93%-96%	74%-77%	40%-43%
Mid-Atlantic[2,6]	93%-96%	72%-75%	49%-52%
ERCOT	86%-89%	62%-65%	37%-40%
New York[2]	85%-88%	61%-64%	17%-20%
Effective Realized Energy Price ($/MWh)[4]			
Midwest	$29.00	$28.00	$28.00
Mid-Atlantic[2,6]	$39.00	$38.00	$32.50
ERCOT[5]	$4.50	$6.00	$6.50
New York[2]	$37.00	$35.50	$24.50

(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 11 refueling outages in 2019, 14 in 2020, and 13 in 2021 at Exelon-operated nuclear plants and Salem. Expected generation assumes capacity factors of 95.3%, 93.9%, and 94.1% in 2019, 2020, and 2021, respectively at Exelon-operated nuclear plants, at ownership. These estimates of expected generation in 2020 and 2021 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
(6) Reflects TMI retirement in September 2019

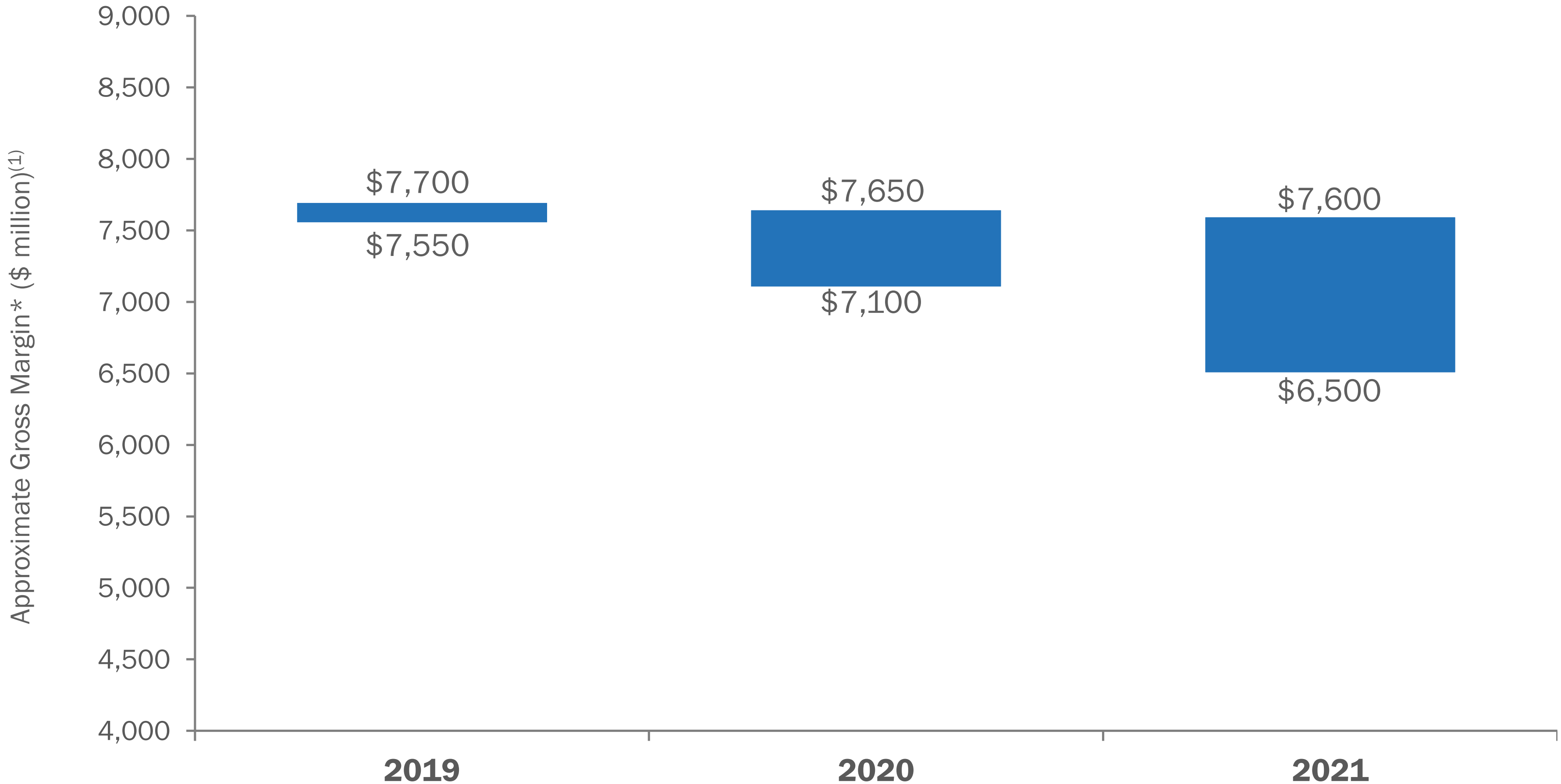
Exelon

ExGen Hedged Gross Margin* Sensitivities

Gross Margin* Sensitivities (with existing hedges)[1]	2019	2020	2021
Henry Hub Natural Gas ($/MMBtu)			
+ $1/MMBtu	$50	$290	$510
- $1/MMBtu	$(70)	$(265)	$(500)
NiHub ATC Energy Price			
+ $5/MWh	$10	$120	$290
- $5/MWh	$(10)	$(120)	$(290)
PJM-W ATC Energy Price			
+ $5/MWh	$5	$50	$115
- $5/MWh	-	$(45)	$(120)
NYPP Zone A ATC Energy Price			
+ $5/MWh	$5	$20	$60
- $5/MWh	$(5)	$(20)	$(60)
Nuclear Capacity Factor			
+/- 1%	+/- $20	+/- $30	+/- $25

(1) Based on June 30, 2019, market conditions and hedged position; gas price sensitivities are based on an assumed gas-power relationship derived from an internal model that is updated periodically; power price sensitivities are derived by adjusting the power price assumption while keeping all other price inputs constant; due to correlation of the various assumptions, the hedged gross margin impact calculated by aggregating individual sensitivities may not be equal to the hedged gross margin impact calculated when correlations between the various assumptions are also considered; sensitivities based on commodity exposure which includes open generation and all committed transactions; excludes EDF's equity share of CENG Joint Venture

ExGen Hedged Gross Margin* Upside/Risk



(1) Represents an approximate range of expected gross margin, taking into account hedges in place, between the 5th and 95th percent confidence levels assuming all unhedged supply is sold into the spot market; approximate gross margin ranges are based upon an internal simulation model and are subject to change based upon market inputs, future transactions and potential modeling changes; these ranges of approximate gross margin in 2020 and 2021 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 June 30, 2019. Gross Margin Upside/Risk based on commodity exposure which includes open generation and all committed transactions. Reflects TMI retirement in September 2019.

Illustrative Example of Modeling Exelon Generation 2020 Total Gross Margin*

Row	Item	Midwest	Mid-Atlantic	ERCOT	New York	South, West, NE & Canada
(A)	Start with fleet-wide open gross margin			$3.55 billion		
(B)	Capacity and ZEC			$1.9 billion		
(C)	Expected Generation (TWh)	96.5	48.0	25.1	15.7	
(D)	Hedge % (assuming mid-point of range)	75.5%	73.5%	63.5%	62.5%	
(E=C*D)	Hedged Volume (TWh)	72.9	35.3	15.9	9.8	
(F)	Effective Realized Energy Price ($/MWh)	$28.00	$38.00	$6.00	$35.50	
(G)	Reference Price ($/MWh)	$22.92	$27.63	$8.46	$29.32	
(H=F-G)	Difference ($/MWh)	$5.08	$10.37	($2.46)	$6.18	
(I=E*H)	Mark-to-Market value of hedges ($ million)[(1)]	$370	$365	($40)	$60	
(J=A+B+I)	Hedged Gross Margin ($ million)			$6,200		
(K)	Power New Business / To Go ($ million)			$600		
(L)	Non-Power Margins Executed ($ million)			$200		
(M)	Non-Power New Business / To Go ($ million)			$300		
(N=J+K+L+M)	**Total Gross Margin***			**$7,300 million**		

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

Exelon

Additional ExGen Modeling Data

Total Gross Margin Reconciliation (in $M)[1]	2019	2020	2021
Revenue Net of Purchased Power and Fuel Expense*[2,3]	**$8,075**	**$7,725**	**$7,300**
Other Revenues[4]	$(175)	$(175)	$(150)
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses	$(250)	$(250)	$(250)
Total Gross Margin* (Non-GAAP)	**$7,650**	**$7,300**	**$6,900**

Key ExGen Modeling Inputs (in $M)[1,5]	2019
Other[6]	$125
Adjusted O&M*[7]	$(4,325)
Taxes Other Than Income (TOTI)[8]	$(400)
Depreciation & Amortization*[9]	$(1,125)
Interest Expense	$(400)
Effective Tax Rate	21.0%

(1) All amounts rounded to the nearest $25M
(2) ExGen does not forecast the GAAP components of RNF separately, as to do so would be unduly burdensome. RNF also includes the RNF of our proportionate ownership share of CENG.
(3) Excludes the Mark-to-Market impact of economic hedging activities due to the volatility and unpredictability of the future changes to power prices
(4) Other Revenues primarily reflects revenues from variable interest entities, funds collected through revenues for decommissioning the former PECO nuclear plants through regulated rates, gross receipts tax revenues and JExel Nuclear JV
(5) ExGen amounts for O&M, TOTI, Depreciation & Amortization; excludes EDF's equity ownership share of the CENG Joint Venture
(6) Other reflects Other Revenues excluding gross receipts tax revenues, includes nuclear decommissioning trust fund earnings from unregulated sites, and includes the minority interest in ExGen Renewables JV and Bloom
(7) Adjusted O&M* includes $200M of non-cash expense related to the increase in the ARO liability due to the passage of time
(8) TOTI excludes gross receipts tax of $150M
(9) 2020 Depreciation & Amortization is favorable to 2019 by $50M, while 2021 Depreciation & Amortization is favorable to 2019 by $25M

Appendix

Reconciliation of Non-GAAP Measures

Q2 QTD GAAP EPS Reconciliation

Three Months Ended June 30, 2019	ComEd	PECO	BGE	PHI	ExGen	Other	Exelon
2019 GAAP Earnings (Loss) Per Share	**$0.19**	**$0.10**	**$0.05**	**$0.11**	**$0.11**	**($0.07)**	**$0.50**
Mark-to-market impact of economic hedging activities	-	-	-	-	0.07	-	0.07
Unrealized losses related to NDT funds	-	-	-	-	0.05	-	0.05
Plant retirements and divestitures	-	-	-	-	(0.02)	-	(0.02)
Cost management program	-	-	-	-	-	-	0.01
Litigation settlement gain	-	-	-	-	(0.02)	-	(0.02)
Noncontrolling interests	-	-	-	-	0.02	-	0.02
2019 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	**$0.19**	**$0.11**	**$0.05**	**$0.11**	**$0.21**	**($0.06)**	**$0.60**

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

Q2 QTD GAAP EPS Reconciliation (continued)

Three Months Ended June 30, 2018	ComEd	PECO	BGE	PHI	ExGen	Other	Exelon
2018 GAAP Earnings (Loss) Per Share	**$0.17**	**$0.10**	**$0.05**	**$0.09**	**$0.18**	**($0.04)**	**$0.56**
Mark-to-market impact of economic hedging activities	-	-	-	-	(0.07)	-	(0.07)
Unrealized losses related to NDT funds	-	-	-	-	0.08	-	0.08
Long-lived asset impairments	-	-	-	-	0.03	-	0.03
Plant retirements and divestitures	-	-	-	-	0.14	-	0.14
Cost management program	-	-	-	-	0.01	-	0.01
Change in environmental liabilities	-	-	-	-	0.01	-	0.01
Reassessment of deferred income taxes	-	-	-	-	-	(0.01)	(0.01)
Noncontrolling interests	-	-	-	-	(0.04)	-	(0.04)
2018 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	**$0.17**	**$0.10**	**$0.05**	**$0.09**	**$0.34**	**($0.05)**	**$0.71**

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

Exelon.

Q2 YTD GAAP EPS Reconciliation

Six Months Ended June 30, 2019	ComEd	PECO	BGE	PHI	ExGen	Other	Exelon
2019 GAAP Earnings (Loss) Per Share	**$0.35**	**$0.28**	**$0.21**	**$0.23**	**$0.48**	**($0.13)**	**$1.43**
Mark-to-market impact of economic hedging activities	-	-	-	-	0.09	0.01	0.10
Unrealized gains related to NDT funds	-	-	-	-	(0.14)	-	(0.14)
Long-lived asset impairments	-	-	-	-	0.01	-	0.01
Cost management program	-	-	-	-	0.01	-	0.02
Litigation settlement gain	-	-	-	-	(0.02)	-	(0.02)
Noncontrolling interests	-	-	-	-	0.08	-	0.08
2019 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	**$0.35**	**$0.28**	**$0.21**	**$0.23**	**$0.51**	**$(0.12)**	**$1.47**

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

Q2 YTD GAAP EPS Reconciliation (continued)

Six Months Ended June 30, 2018	ComEd	PECO	BGE	PHI	ExGen	Other	Exelon
2018 GAAP Earnings (Loss) Per Share	**$0.34**	**$0.22**	**$0.18**	**$0.15**	**$0.32**	**($0.06)**	**$1.16**
Mark-to-market impact of economic hedging activities	-	-	-	-	0.13	-	0.13
Unrealized losses related to NDT funds	-	-	-	-	0.15	-	0.15
Long-lived asset impairments	-	-	-	-	0.03	-	0.03
Plant retirements and divestitures	-	-	-	-	0.23	-	0.23
Cost management program	-	-	-	-	0.01	-	0.02
Change in environmental liabilities	-	-	-	-	0.01	-	0.01
Reassessment of deferred income taxes	-	-	-	-	-	(0.01)	(0.01)
Noncontrolling interests	-	-	-	-	(0.06)	-	(0.06)
2018 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	**$0.34**	**$0.22**	**$0.19**	**$0.16**	**$0.83**	**($0.07)**	**$1.66**

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

Projected GAAP to Operating Adjustments

- **Exelon's projected 2019 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 funds to the extent not offset by contractual accounting as described in the notes to the consolidated financial statements;
  - Asset impairments;
  - Impacts related to early plant retirements and divestitures;
  - Certain costs incurred to achieve cost management program savings;
  - Other unusual items; and
  - Generation's noncontrolling interest related to CENG exclusion items.

GAAP to Non-GAAP Reconciliations[1]

Exelon FFO/Debt[2] = $\frac{\text{FFO (a)}}{\text{Adjusted Debt (b)}}$

Exelon FFO Calculation[2]

GAAP Operating Income
+ Depreciation & Amortization
= EBITDA
- GAAP Interest Expense
+/- GAAP Current Income Tax (Expense)/Benefit
+ Nuclear Fuel Amortization
+/- GAAP to Operating Adjustments
+/- Other S&P Adjustments
= FFO (a)

Exelon Adjusted Debt Calculation[1]

Long-Term Debt (including current maturities)
+ Short-Term Debt
+ Purchase Power Agreement and Operating Lease Imputed Debt
+ Pension/OPEB Imputed Debt (after-tax)
- Off-Credit Treatment of Non-Recourse Debt
- Cash on Balance Sheet * 75%
+/- Other S&P Adjustments
= Adjusted Debt (b)

(1) 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; therefore, management is unable to reconcile these measures
(2) Calculated using S&P Methodology. Due to ring-fencing, S&P deconsolidates BGE from Exelon and analyzes solely as an equity investment

GAAP to Non-GAAP Reconciliations[1]

ExGen Debt/EBITDA = $\dfrac{\text{Net Debt (a)}}{\text{Operating EBITDA (b)}}$

ExGen Debt/EBITDA Excluding Non-Recourse = $\dfrac{\text{Net Debt (c)}}{\text{Operating EBITDA (d)}}$

ExGen Net Debt Calculation

Long-Term Debt (including current maturities)
+ Short-Term Debt
- Cash on Balance Sheet

= Net Debt (a)

ExGen Net Debt Calculation Excluding Non-Recourse

Long-Term Debt (including current maturities)
+ Short-Term Debt
- Cash on Balance Sheet
- Non-Recourse Debt

= Net Debt Excluding Non-Recourse (c)

ExGen Operating EBITDA Calculation

GAAP Operating Income
+ Depreciation & Amortization
= EBITDA
+/- GAAP to Operating Adjustments

= Operating EBITDA (b)

ExGen Operating EBITDA Calculation Excluding Non-Recourse

GAAP Operating Income
+ Depreciation & Amortization
= EBITDA
+/- GAAP to Operating Adjustments
- EBITDA from Projects Financed by Non-Recourse Debt

= Operating EBITDA Excluding Non-Recourse (d)

(1) 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; therefore, management is unable to reconcile these measures

GAAP to Non-GAAP Reconciliations

Q2 2019 Operating ROE Reconciliation ($M)	PHI Utilities	Legacy EXC Utilities	Consolidated EU
Net Income (GAAP)	$473	$1,539	$2,012
Operating Exclusions	$25	$6	$31
Adjusted Operating Earnings	$499	$1,545	$2,043
Average Equity	$5,457	$14,665	$20,122
Operating ROE (Adjusted Operating Earnings/Average Equity) (Non-GAAP)	**9.1%**	**10.5%**	**10.2%**

Q1 2019 Operating ROE Reconciliation ($M)	PHI Utilities	Legacy EXC Utilities	Consolidated EU
Net Income (GAAP)	$454	$1,516	$1,970
Operating Exclusions	$26	$7	$33
Adjusted Operating Earnings	$479	$1,523	$2,003
Average Equity	$5,171	$14,477	$19,648
Operating ROE (Adjusted Operating Earnings/Average Equity) (Non-GAAP)	**9.3%**	**10.5%**	**10.2%**

ExGen Adjusted O&M Reconciliation ($M)(1)	2019
GAAP O&M	**$4,950**
Decommissioning(2)	125
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses(3)	(250)
O&M for managed plants that are partially owned	(400)
Other	(100)
Adjusted O&M (Non-GAAP)	**$4,325**

Note: Items may not sum due to rounding
(1) All amounts rounded to the nearest $25M
(2) Reflects asset retirement obligation update for TMI and earnings neutral O&M
(3) Reflects the direct cost of sales of certain businesses, which are included in Total Gross Margin*

GAAP to Non-GAAP Reconciliations

2019 Adjusted Cash from Ops Calculation ($M)[1]	BGE	ComEd	PECO	PHI	ExGen	Other	Exelon
Net cash flows provided by operating activities (GAAP)	$675	$1,325	$750	$1,050	$4,000	($275)	$7,525
Other cash from investing activities	-	-	-	-	($275)	-	($275)
Counterparty collateral activity	-	-	-	-	$250	-	$250
Adjusted Cash Flow from Operations (Non-GAAP)	**$675**	**$1,325**	**$750**	**$1,050**	**$3,950**	**($275)**	**$7,500**

2019 Cash From Financing Calculation ($M)[1]	BGE	ComEd	PECO	PHI	ExGen	Other	Exelon
Net cash flow provided by financing activities (GAAP)	$525	$450	$150	$225	($1,750)	$150	($250)
Dividends paid on common stock	$225	$500	$350	$350	$900	($925)	$1,400
Financing Cash Flow (Non-GAAP)	**$750**	**$950**	**$500**	**$575**	**($850)**	**($775)**	**$1,150**

Exelon Total Cash Flow Reconciliation[1]	2019
GAAP Beginning Cash Balance	**$1,250**
Adjustment for Cash Collateral Posted	$575
Adjusted Beginning Cash Balance[3]	$1,825
Net Change in Cash (GAAP)[2]	($200)
Adjusted Ending Cash Balance[3]	$1,625
Adjustment for Cash Collateral Posted	($700)
GAAP Ending Cash Balance	**$925**

(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