

# Earnings Conference Call First Quarter 2020

May 8, 2020



# Cautionary Statements Regarding Forward-Looking Information

This presentation contains certain written and oral forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are subject to risks and uncertainties including among others those related to the expected or potential impact of the novel coronavirus (COVID-19) pandemic, and the related responses of various governments and regulatory bodies, our customers, and the company, on our business, financial condition and results of operations; any such forward-looking statements, whether concerning the COVID-19 pandemic or otherwise, involve risks, assumptions and uncertainties. Words such as “could,” “may,” “expects,” “anticipates,” “will,” “targets,” “goals,” “projects,” “intends,” “plans,” “believes,” “seeks,” “estimates,” “predicts,” and variations on such words, and similar expressions that reflect our current views with respect to future events and operational, economic and financial performance, are intended to identify such forward-looking statements.

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 2019 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 18, Commitments and Contingencies; (2) the Registrants’ First Quarter 2020 Quarterly Report on Form 10-Q (to be filed on May 8, 2020) in (a) Part II, ITEM 1A. Risk Factors; (b) Part I, ITEM 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, ITEM 1. Financial Statements: Note 14, Commitments and Contingencies; and (3) other factors discussed in filings with the SEC by the Registrants.

Investors are cautioned not to place undue reliance on these forward-looking statements, whether written or oral, 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

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

- **Adjusted operating earnings** exclude certain costs, expenses, gains and losses and other specified items, including mark-to-market adjustments from economic hedging activities, unrealized gains and losses from nuclear decommissioning trust fund investments, asset impairments, certain amounts associated with plant retirements and divestitures, costs related to cost management programs, asset retirement obligations 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

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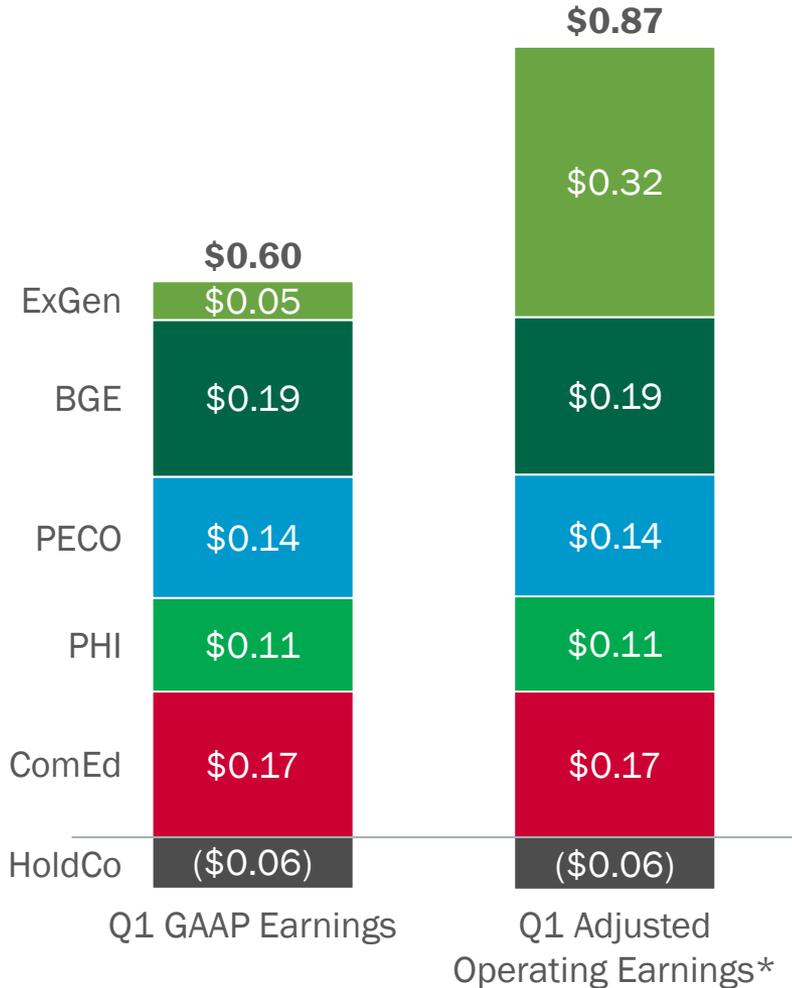
This information is intended to enhance an investor's overall understanding of period over period financial results and provide an indication of Exelon's baseline operating performance by excluding items that are considered by management to be not directly related to the ongoing operations of the business.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

These non-GAAP financial measures are not a presentation defined under GAAP and may not be comparable to other companies' presentations. 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 44 of this presentation.

# First Quarter Results

## Q1 2020 EPS Results<sup>(1)</sup>



## Q1 Highlights

- Offset earnings pressure from extremely warm winter
- All utilities had first quartile outage frequency and duration performance
- Top decile customer satisfaction for BGE, ComEd and PECO
- Record-setting nuclear refueling outages
- Prior to stay at home order in Illinois, subject matter hearings held in both chambers and Governor launched legislative working groups

<sup>(1)</sup> Amounts may not sum due to rounding

# COVID-19: Focusing on Safety and Well Being of Our Employees

## Ensuring Employee Safety

- As a provider of critical national infrastructure, Exelon routinely plans and drills for disruptive and catastrophic events
  - More than half our employees are working remotely, including call centers
  - Following CDC/state guidelines on health & safety
  - In-house nursing staff available to employees
  - Enhanced workplace cleaning and disinfecting
  - Portable wash and sanitizing stations and washrooms
  - Pre-entry screening at plants, utility control rooms
  - All appropriate Personal Protective Equipment (PPE) for field, plant and office employees
  - Manufacturing hand sanitizer in-house

## Providing Additional Benefits

- Cover all in-network medical expenses associated with COVID-19 testing and treatment for employees and covered dependents
- Full pay continuation for employees who contract COVID-19 or are required to quarantine
- Expanded access to back-up dependent care
- Offering medical concierge program for employees and dependents who are COVID-19 positive, telehealth benefits, employee assistance program, and other wellness resources

# COVID-19: Operational Excellence is Even More Critical

**Maintaining our infrastructure is critical to ensuring hospitals, health care providers, grocery stores and medical and food production facilities can provide their services and goods**



## Exelon Utilities:

- Sustained first quartile reliability performance through April at each utility
- Restored more than **350,000** customers after March and April storms
- Successful, first ever virtual activation for mutual assistance at ComEd to help Exelon's Mid-Atlantic utilities
- 2020 capital plans on track
- Service levels remain high even with customer representatives working from home



## Exelon Generation:

- Completed **7 of 8** spring nuclear outages, with 8<sup>th</sup> to be completed later this month; nearly all outages were shorter than planned
- Completed **26** planned outages at fossil and renewable sites
- **100%** capacity factor at non-outage nuclear plants in April
- Constellation and broader ExGen maintained continuity around critical control room and dispatch operations

# COVID-19: Supporting our Customers and Communities



## Suspending utility customer disconnections

- Extending our customer support policies, which include suspending service disconnections, waiving new late fees, and reconnecting customers who were previously disconnected
- Offering assistance programs and flexible payment arrangements to customers experiencing temporary or extended financial hardship



## Supporting communities through charitable contributions

- Exelon Foundation, Exelon Corporation and our family of companies have contributed more than \$5.9 million to national and local relief organizations for immediate relief to communities impacted by COVID-19, including support with food, health and financial needs
- Accelerating charitable contributions to other organizations as needed
- Connecting employees interested in volunteer opportunities, including those that can be done from home, meeting the need for blood donations, and supporting local food banks



## Using our unique skills and resources to help the community

- Each utility is inspecting circuits and equipment at hospitals, testing facilities, and medical manufacturing sites to ensure reliable service to these critical resources
- Helped repurpose local facilities into alternate care centers for COVID-19 patients and testing sites
- Provided ComEd's mobile bridge to help create a drive thru COVID-19 testing site for first responders in Illinois

# Actively Managing the Challenge of COVID-19

**\$250M in 2020 from Cost Savings**

**Reducing ExGen CapEx by \$125M**

**Seeking Recovery for COVID-19 Costs from Regulators**

**ExGen outlook is projected to be (\$0.10) per share from Q1 weather and from COVID-19 net of cost savings; Total ExGen free cash flow \$100M lower**

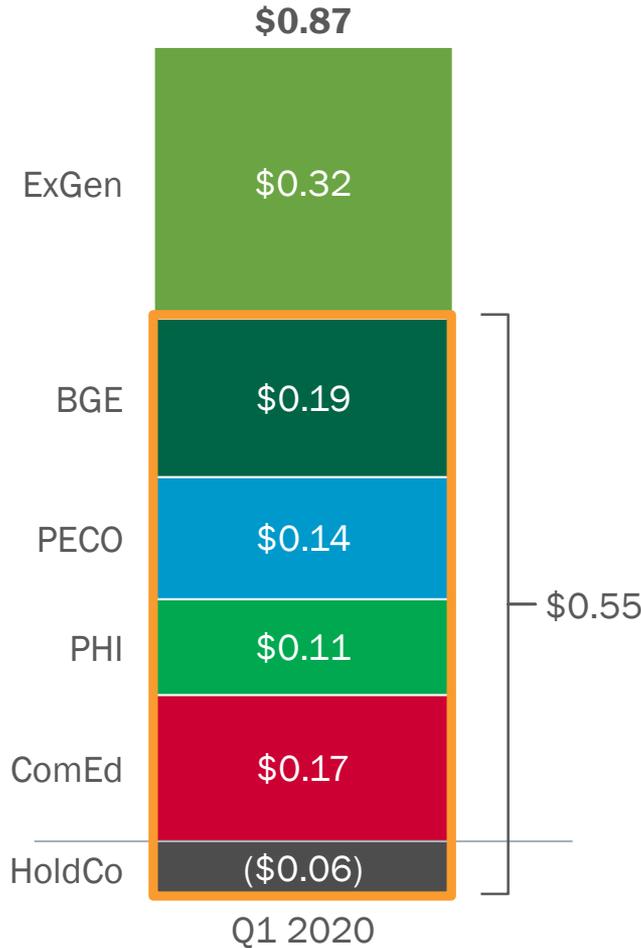
**Exelon Utilities outlook is projected to be (\$0.10) per share from ComEd ROE and Q1 weather and flat from COVID-19**

**Revising full year operating earnings guidance to \$2.80 - \$3.10 per share**

# First Quarter Adjusted Operating Earnings\* Drivers

Q1 2020 Adjusted Operating EPS\* Results

Q1 2020 vs. Guidance of \$0.85 - \$0.95



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

### Exelon Utilities

- ↓ Unfavorable weather
- ↑ Timing of O&M

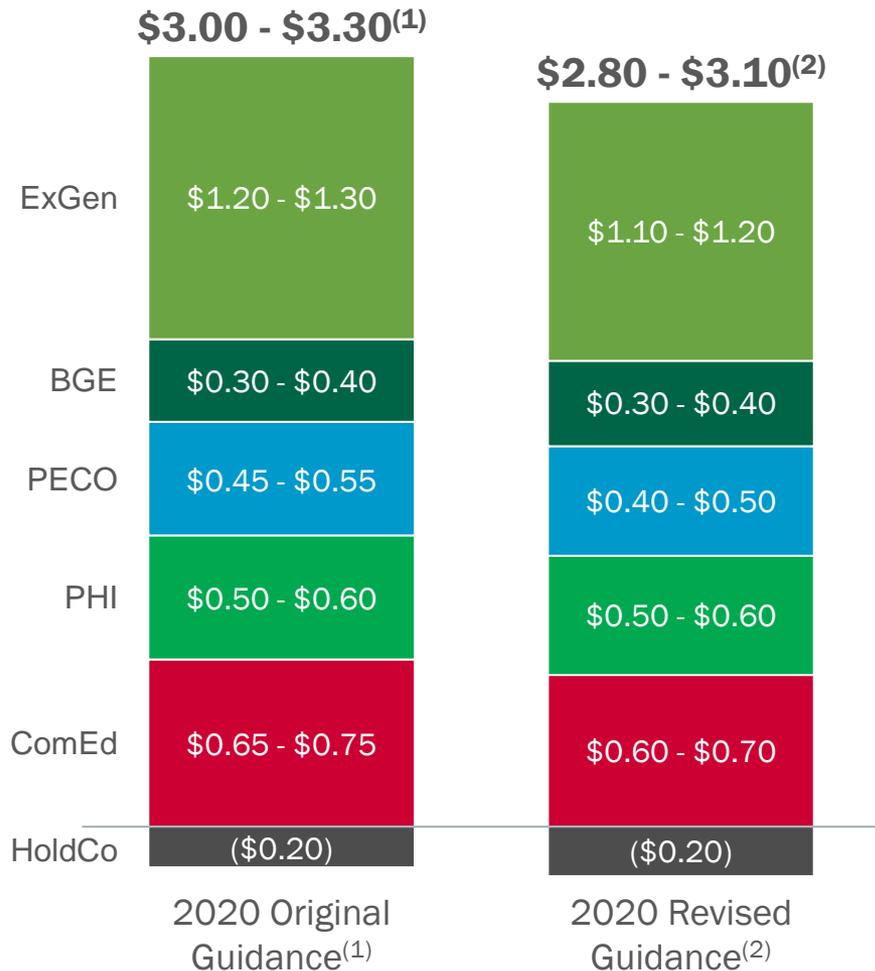
### Exelon Generation

- ↓ Unfavorable weather
- ↓ Salem and Fitzpatrick outages
- ↑ Favorable O&M
- ↑ NDT realized gains<sup>(1)</sup>

Note: Amounts may not sum due to rounding

(1) Gains related to unregulated sites

# Revising 2020 Adjusted Operating Earnings\* Guidance



## Guidance Assumptions

Stay-at-home orders and widespread business shut-downs from mid-March through mid-June. Load assumed to gradually recover over the subsequent months.

### Load

- In Q2, we assume C&I load to decrease by 9-15%, and Residential load to increase by 4-7%. By Q4, we assume C&I load to decrease by 2-6% and Residential load to be flat to down 2%.

### Bad Debt

- At Exelon Utilities (EU) we anticipate recovery of COVID-19 bad debt<sup>(3)</sup>
- At ExGen, bad debt expense is estimated based on impacts seen in '08-'09 recession and current analysis by customer class

### Other

- ComEd Distribution ROE based on the 30-Year U.S. Treasury yield, which was 1.35% as of 3/31/2020
- Reflects impact of very warm Q1 weather net of cost offsets

**Expect Q2 2020 Adjusted Operating Earnings\* of \$0.35 - \$0.45 per share**

Note: Amounts may not sum due to rounding

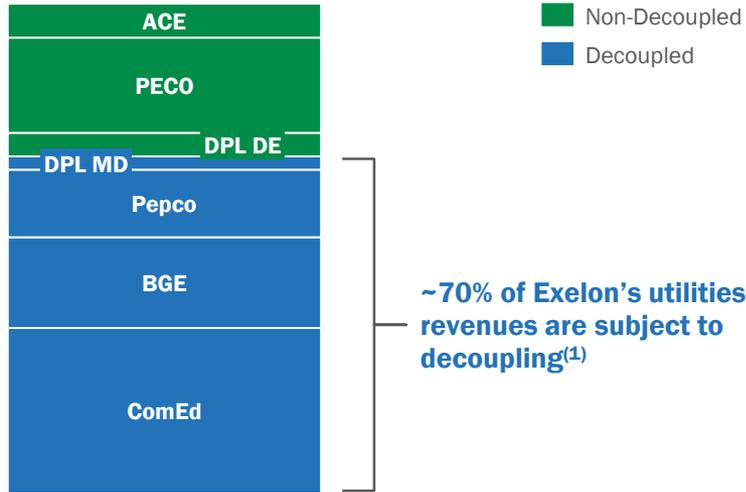
(1) 2020E original earnings guidance based on expected average outstanding shares of 978M

(2) 2020E revised earnings guidance based on expected average outstanding shares of 977M

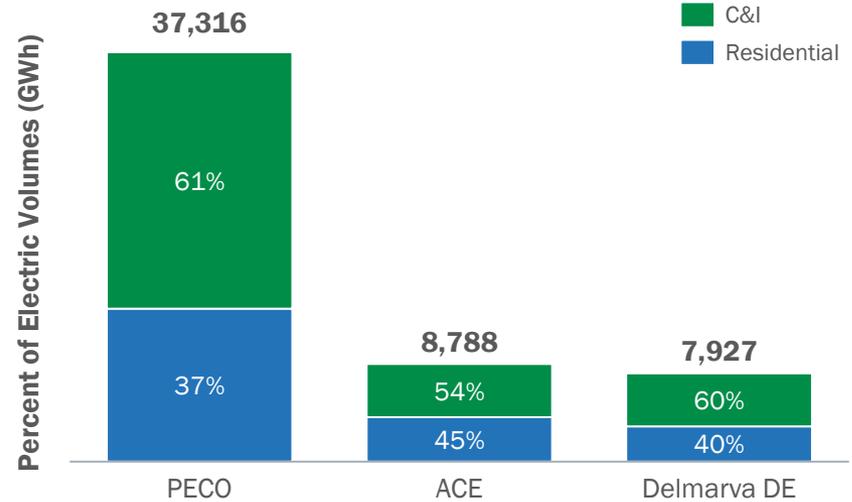
(3) More detail on COVID-19 cost recovery can be found on slides 26 and 27 in the appendix

# COVID-19 Impacts on Electric Utilities

## Revenue Decoupling Mitigates Load Fluctuations



## Customer Breakdown of 2019 Non-Decoupled Volumes<sup>(2)</sup>



## Load Impacts

- Preliminary April utility load data is down approximately 8% year-over-year across the utilities (weather-normalized)
  - C&I load is down ~10-15% as a full month of business closures weakened load growth
  - Residential load is up ~3-7% driven by stay-at-home orders

## Sensitivities

Balance of Year Sensitivities	Operating Net Income* (\$M)
C&I Load Volumes (+/- 1%)	+/- \$6M
Residential Load Volumes (+/- 1%)	+/- \$7M
ComEd Distribution ROE (+/-50 bps) <sup>(3)</sup>	+/- \$23M

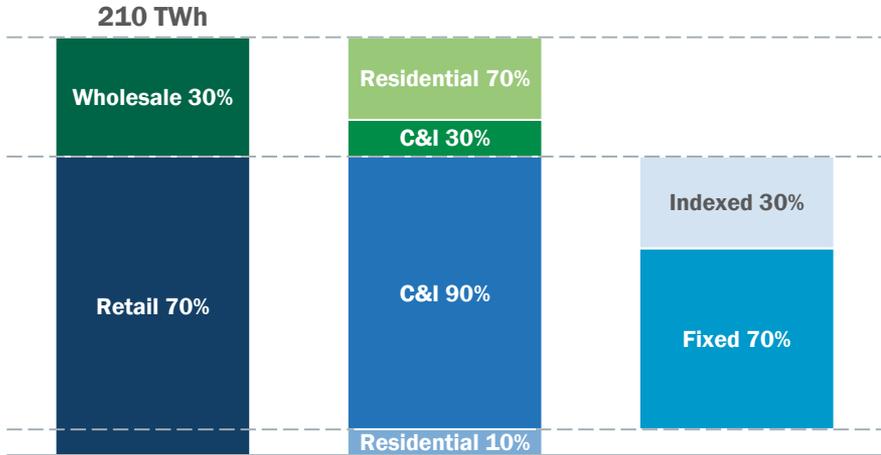
(1) Reflects both electric and gas revenues; ComEd's formula rate includes a mechanism that eliminates volumetric risk

(2) Remainder of volumes not captured in chart reflect public authorities or other customers

(3) ComEd distribution ROE reflects sensitivity to 50 basis point move based on 3/31/2020 30-year Treasury rates

# COVID-19 Impacts on Constellation

## Customer Breakdown of 2019 Load Served<sup>(1)</sup>

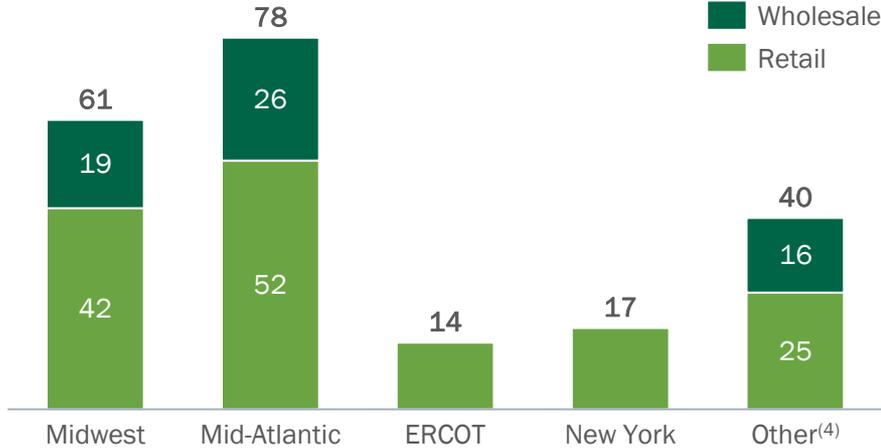


## Load Impacts and Sensitivities

- Preliminary April data<sup>(2)</sup> suggests 10-15% C&I load reductions in PJM, with slightly lower reductions in ERCOT. Residential load up ~5-7% across most regions.
- For the balance of 2020, approximately 125 TWh of Constellation load is fixed price

Balance of Year Sensitivities <sup>(3)</sup>	Operating Net Income* (\$M)
C&I Load Volumes (+/- 1%)	+/- \$15M
Residential Load Volumes (+/- 1%)	+/- \$7M

## 2019 Power Load Served by Region (TWh)<sup>(1)</sup>



## C&I Business Strategy Remains Intact

Despite the COVID-19 load shock, serving C&I customers remains integral to our strategy

- Constellation gross margin is driven primarily by our customer-facing businesses, which accounts for the majority of our gross margin
- Opportunity to serve full suite of innovative products, commodities, and clean energy solutions to highly rated counterparties in multiple locations
- Customer usage pattern aligns with our generation portfolio from a hedging perspective

(1) Includes Retail and Wholesale load auction volumes only  
 (2) Data based off initial ISO settlements and subject to future true-ups. Results shown may vary by sub-region.  
 (3) Load volumes sensitivities reflect C&I and residential fixed price only  
 (4) Other includes New England, South and West



# Exelon Generation: Gross Margin\* Update

Gross Margin Category (\$M) <sup>(1)</sup>	March 31, 2020		Change from December 31, 2019	
	2020	2021	2020	2021
Open Gross Margin* <sup>(2)</sup> (including South, West, New England, Canada hedged gross margin)	\$2,850	\$3,350	\$(750)	\$(100)
Capacity and ZEC Revenues <sup>(2)</sup>	\$1,900	\$1,850	-	-
Mark-to-Market of Hedges <sup>(2,3)</sup>	\$1,500	\$450	\$650	\$100
Power New Business / To Go	\$300	\$650	\$(150)	\$(100)
Non-Power Margins Executed	\$300	\$200	\$50	\$50
Non-Power New Business / To Go	\$150	\$300	\$(100)	\$(50)
<b>Total Gross Margin*<sup>(4)</sup></b>	<b>\$7,000</b>	<b>\$6,800</b>	<b>\$(300)</b>	<b>\$(100)</b>

## Recent Developments

- 2020 Total Gross Margin\* is projected to be down \$300M primarily due to COVID-19 impacts on load and Q1 unfavorable weather
- 2021 Total Gross Margin\* is projected to be down \$100M primarily due to declining power prices and modest continued impacts of COVID-19
- Executed a combined \$150M and \$100M of power and non-power new business in 2020 and 2021, respectively
- Behind ratable hedging position:
  - ~8-11% behind ratable in 2020 when considering cross commodity hedges
  - ~2-5% 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 March 31, 2020 market conditions

# 2020 Projected Sources and Uses of Cash

(\$M) <sup>(1)</sup>	BGE	ComEd	PECO	PHI	Total Utilities	ExGen	Corp <sup>(9)</sup>	Exelon	Cash Balance
<b>Beginning Cash Balance</b> * <sup>(2)</sup>									<b>1,500</b>
Adjusted Cash Flow from Operations <sup>(2)</sup>	625	1,325	750	975	3,675	3,525	(225)	6,975	
Base CapEx and Nuclear Fuel <sup>(3)</sup>	-	-	-	-	-	(1,550)	(100)	(1,650)	
<b>Free Cash Flow*</b>	<b>625</b>	<b>1,325</b>	<b>750</b>	<b>975</b>	<b>3,675</b>	<b>1,975</b>	<b>(325)</b>	<b>5,325</b>	
Debt Issuances	400	1,000	350	500	2,250	975	2,000	5,225	
Debt Retirements	-	(500)	-	-	(500)	(2,500)	(900)	(3,900)	
Project Financing	-	-	-	-	-	(100)	-	(100)	
Equity Issuance/Share Buyback	-	-	-	-	-	-	-	-	
AR Securitization <sup>(4)</sup>	-	-	-	-	-	500	-	500	
Contribution from Parent	425	500	225	300	1,450	-	(1,450)	-	
Other Financing <sup>(5)</sup>	75	450	125	100	750	200	(250)	700	
<b>Financing</b> * <sup>(6)</sup>	<b>875</b>	<b>1,450</b>	<b>700</b>	<b>900</b>	<b>3,950</b>	<b>(925)</b>	<b>(575)</b>	<b>2,425</b>	
<b>Total Free Cash Flow and Financing</b>	<b>1,525</b>	<b>2,775</b>	<b>1,450</b>	<b>1,850</b>	<b>7,600</b>	<b>1,050</b>	<b>(900)</b>	<b>7,750</b>	
Utility Investment	(1,275)	(2,325)	(1,125)	(1,625)	(6,350)	-	-	(6,350)	
ExGen Growth <sup>(3,7)</sup>	-	-	-	-	-	(125)	-	(125)	
Acquisitions and Divestitures	-	-	-	-	-	-	-	-	
Equity Investments	-	-	-	-	-	(25)	-	(25)	
Dividend <sup>(8)</sup>	-	-	-	-	-	-	-	(1,500)	
<b>Other CapEx and Dividend</b>	<b>(1,275)</b>	<b>(2,325)</b>	<b>(1,125)</b>	<b>(1,625)</b>	<b>(6,350)</b>	<b>(125)</b>	<b>-</b>	<b>(7,975)</b>	
<b>Total Cash Flow</b>	<b>250</b>	<b>450</b>	<b>350</b>	<b>225</b>	<b>1,250</b>	<b>925</b>	<b>(900)</b>	<b>(225)</b>	
<b>Ending Cash Balance</b> * <sup>(2)</sup>									<b>1,300</b>

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

## Key Variances to Q4 Update

- Total free cash is down **\$775M** from our last disclosure, largely related to timing issues
  - Utility operating cash flow is unfavorable **\$600M** primarily due to slowdown of customer collections, which is expected to reverse beginning in 2021
  - ExGen free cash flow is down **\$100M** reflecting lower gross margin offset by cost savings and lower capex
- Capex:
  - Utility capex is **\$125M** lower (less than 2% of total spend) with expected modest delays in activity
  - ExGen capex is down **\$125M** primarily due to nuclear capital savings

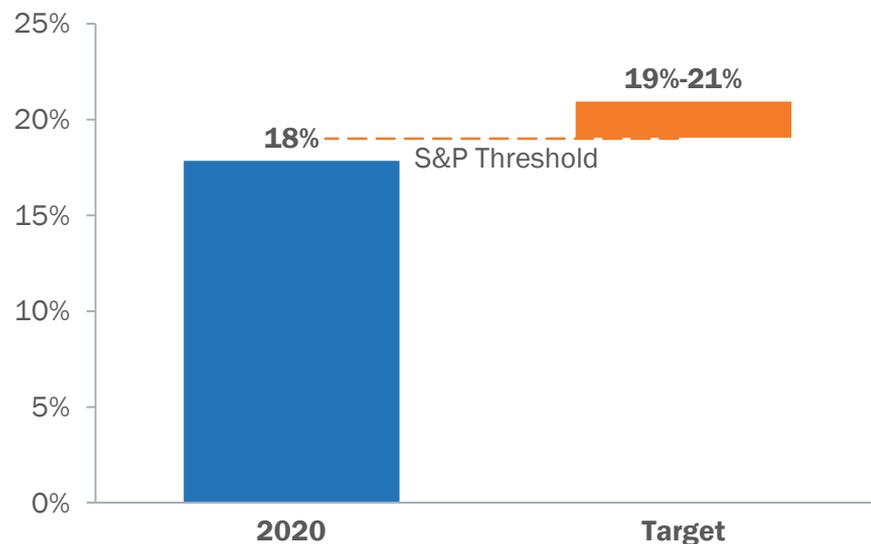
**~80% of free cash flow degradation is timing**

# Strong Liquidity Position and Investment Grade Credit Ratings

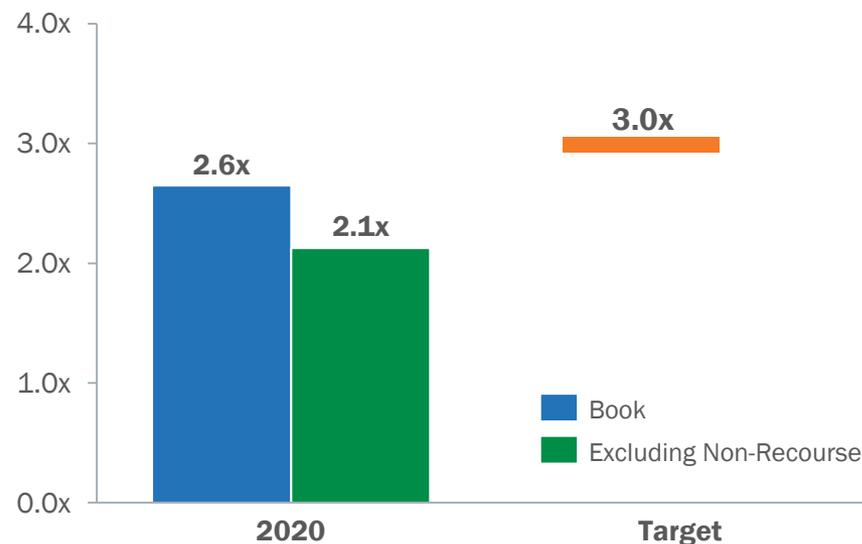
## Significant Capacity Under Exelon's Primary Revolving Credit Facility (RCF) (\$B)

As of 4/30/20	Corporate	ExGen	PECO	BGE	ComEd	PHI	Total
Primary Revolving Credit Facility <sup>(1)</sup>	0.6	5.3	0.6	0.6	1.0	0.9	9.0
Commercial Paper	-	-	-	(0.1)	-	(0.2)	(0.3)
Facility Draw	-	-	-	-	-	-	-
Posted Letters of Credit (LCs)	-	(0.8)	-	-	-	-	(0.8)
<b>Available Capacity</b>	<b>0.6</b>	<b>4.5</b>	<b>0.6</b>	<b>0.5</b>	<b>1.0</b>	<b>0.7</b>	<b>7.9</b>

### Exelon S&P FFO/Debt %<sup>\*(2)</sup>



### ExGen Debt/EBITDA Ratio<sup>\*(3)</sup>



Note: may not sum due to rounding

(1) Primary Revolving Credit Facility (RCF) excludes \$1.4B of bilateral agreements in place as well as an incremental \$550M RCF at Corporate (closed on April 24<sup>th</sup>)

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

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

# Delivering on our Business Strategy

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**Leading Rate Base Growth at the Utilities**

**Strong Operational Performance at the Utilities**

**Leader in Zero Carbon Electricity**

**Constellation is the Premier Retail Business**

# The Exelon Value Proposition

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- **Regulated Utility Growth** targeting utility EPS rising 6-8% annually from 2019-2023 and rate base growth of 7.3%, representing an expanding majority of earnings
- **ExGen's free cash generation** will support utility growth, ExGen debt reduction, and the external dividend
- **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 2023 planning horizon
- **Capital allocation priorities targeting:**
  - Organic utility growth;
  - Return of capital to shareholders with 5% annual dividend growth through 2020<sup>(1)</sup>; and,
  - Debt reduction

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

# Additional Disclosures

# Operating Highlights

Exelon Utilities Operational Metrics					
Operations	Metric	YTD 2020			
		BGE	ComEd	PECO	PHI
Electric Operations	OSHA Recordable Rate	Yellow	Green	Orange	Yellow
	2.5 Beta SAIFI (Outage Frequency) <sup>(1)</sup>	Green	Green	Green	Green
	2.5 Beta CAIDI (Outage Duration)	Green	Green	Green	Green
Customer Operations	Customer Satisfaction	Green	Green	Green	Yellow
	Abandon Rate	Green	Green	Green	Green
Gas Operations	Gas Odor Response	Green	No Gas Operations	Green	Green

- Reliability performance was strong across the utilities:
  - BGE, ComEd and PECO delivered top decile CAIDI performance, while ComEd scored in the top decile in SAIFI
- Each utility continued to deliver on key customer operations metrics:
  - BGE, ComEd and PECO recorded top decile performance in Customer Satisfaction
  - ComEd and PHI achieved top decile performance in Abandon Rate
  - BGE and PECO performed in top decile in Gas Odor Response

Quartile	
Q1	Q2
Q3	Q4

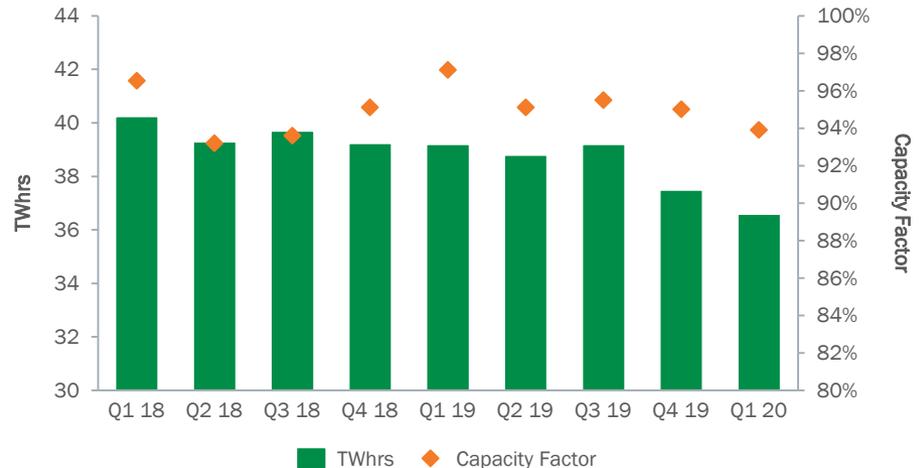
(1) 2.5 Beta SAIFI is YE projection

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

## Exelon Generation Operational Performance

### Exelon Nuclear Fleet<sup>(2)</sup>

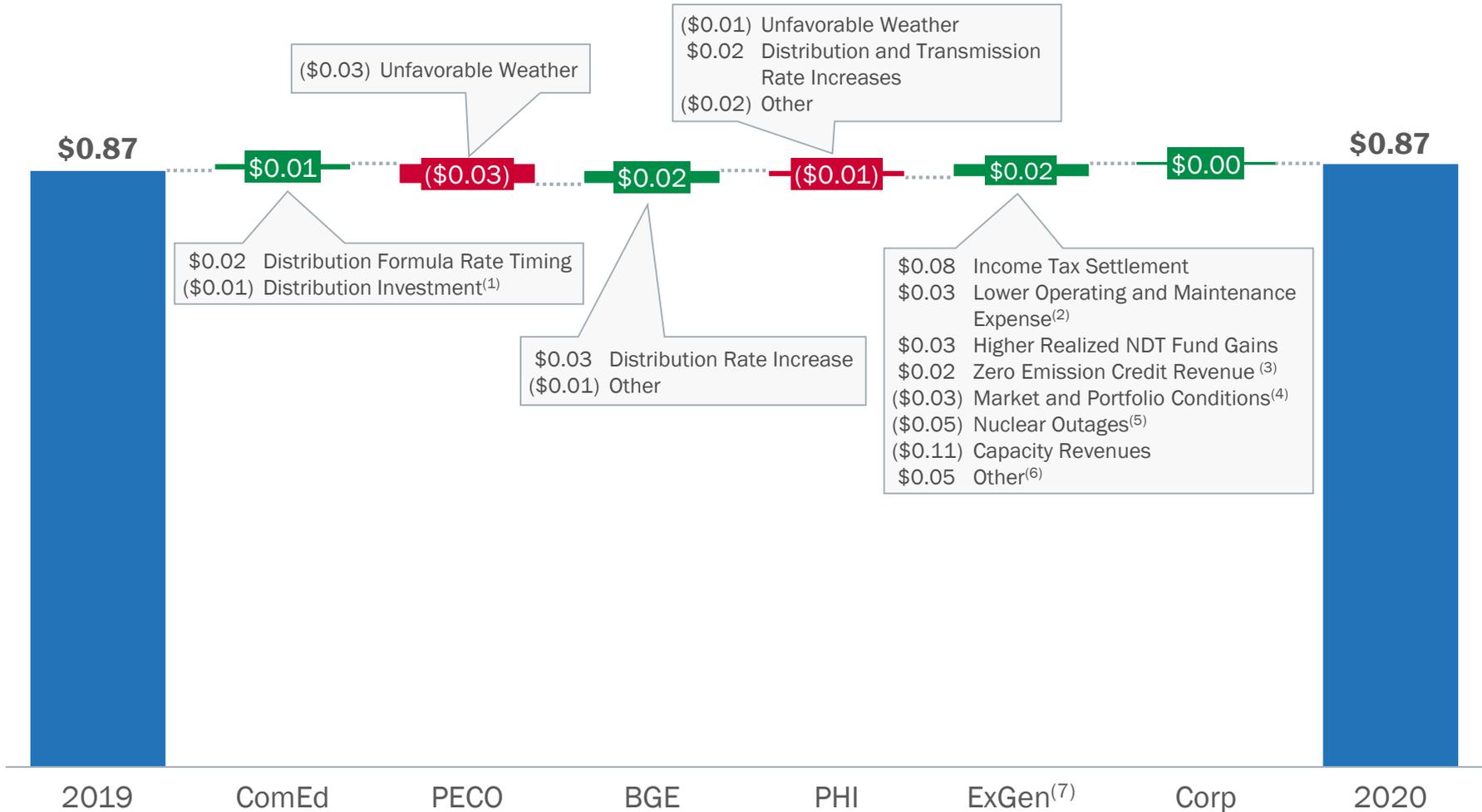
- Best in class performance across our Nuclear fleet:
  - Q1 2020 Nuclear Capacity Factor: 93.9%
  - Owned and operated Q1 2020 production of 36.6 TWh



### Fossil and Renewable Fleet

- Q1 2020 Power Dispatch Match: 98.2%
- Q1 2020 Renewables Energy Capture: 94.7%

# Q1 2020 Adjusted Operating Earnings\* Waterfall



Note: Amounts may not sum due to rounding

- (1) Reflects lower allowed electric distribution ROE due to a decrease in treasury rates, partially offset by higher rate base
- (2) Includes the impacts of previous cost management programs
- (3) Primarily reflects the approval of the New Jersey ZEC Program in the second quarter of 2019
- (4) Primarily reflects lower realized energy prices
- (5) Reflects the revenue and operating and maintenance expense impacts of higher nuclear outage days in 2020
- (6) Primarily reflects the elimination of activity attributable to noncontrolling interest, primarily for CENG
- (7) Drivers reflect CENG ownership at 100%

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

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PUBLIC

## Credit Ratings by Operating Company

Current Ratings <sup>(1)</sup>	ExCorp	ExGen	ComEd	PECO	BGE	ACE	DPL	Pepco
<b>Moody's</b>	Baa2	Baa2	A1	Aa3	A3	A2	A2	A2
<b>S&amp;P</b>	BBB	BBB+	A	A	A	A	A	A
<b>Fitch</b>	BBB+	BBB	A	A+	A	A-	A	A-

## Recent Actions to Support Liquidity

Date(s)	Action
<b>March 19<sup>th</sup></b>	Borrowed <b>\$1.5B</b> on ExGen's RCF
<b>March 19<sup>th</sup>/31<sup>st</sup></b>	Executed <b>\$500M</b> of ExGen term loans
<b>April 1<sup>st</sup></b>	Closed on <b>\$2B</b> Exelon Corporate long-term debt
<b>April 3<sup>rd</sup></b>	Repaid <b>\$1.5B</b> RCF borrowing
<b>April 8<sup>th</sup></b>	Raised <b>\$500M</b> from AR securitization facility
<b>April 24<sup>th</sup></b>	Closed on <b>\$550M</b> incremental 364-day RCF at Corporate

## 2020 Long-Term Financing Schedule (\$B)<sup>(2)</sup>

OpCo	Issuance	Retirements	Status
<b>ExGen</b>	0.5 <sup>(3)</sup>	(1.0)	<b>Complete</b>
<b>ComEd</b>	1.0	(0.5) <sup>(4)</sup>	<b>Complete</b>
<b>PHI</b>	0.5 <sup>(5)</sup>	-	<b>In Progress<sup>(5)</sup></b>
<b>Corporate</b>	2.0	(0.9) <sup>(4)</sup>	<b>Complete</b>
<b>ExGen</b>	1.0	(1.5)	<b>2020</b>
<b>PECO</b>	0.4	-	<b>2020</b>
<b>BGE</b>	0.4	-	<b>2020</b>

(1) Current senior unsecured ratings as of March 31, 2020, for Exelon, Exelon Generation and BGE and senior secured ratings for ComEd, PECO, ACE, DPL, and Pepco

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

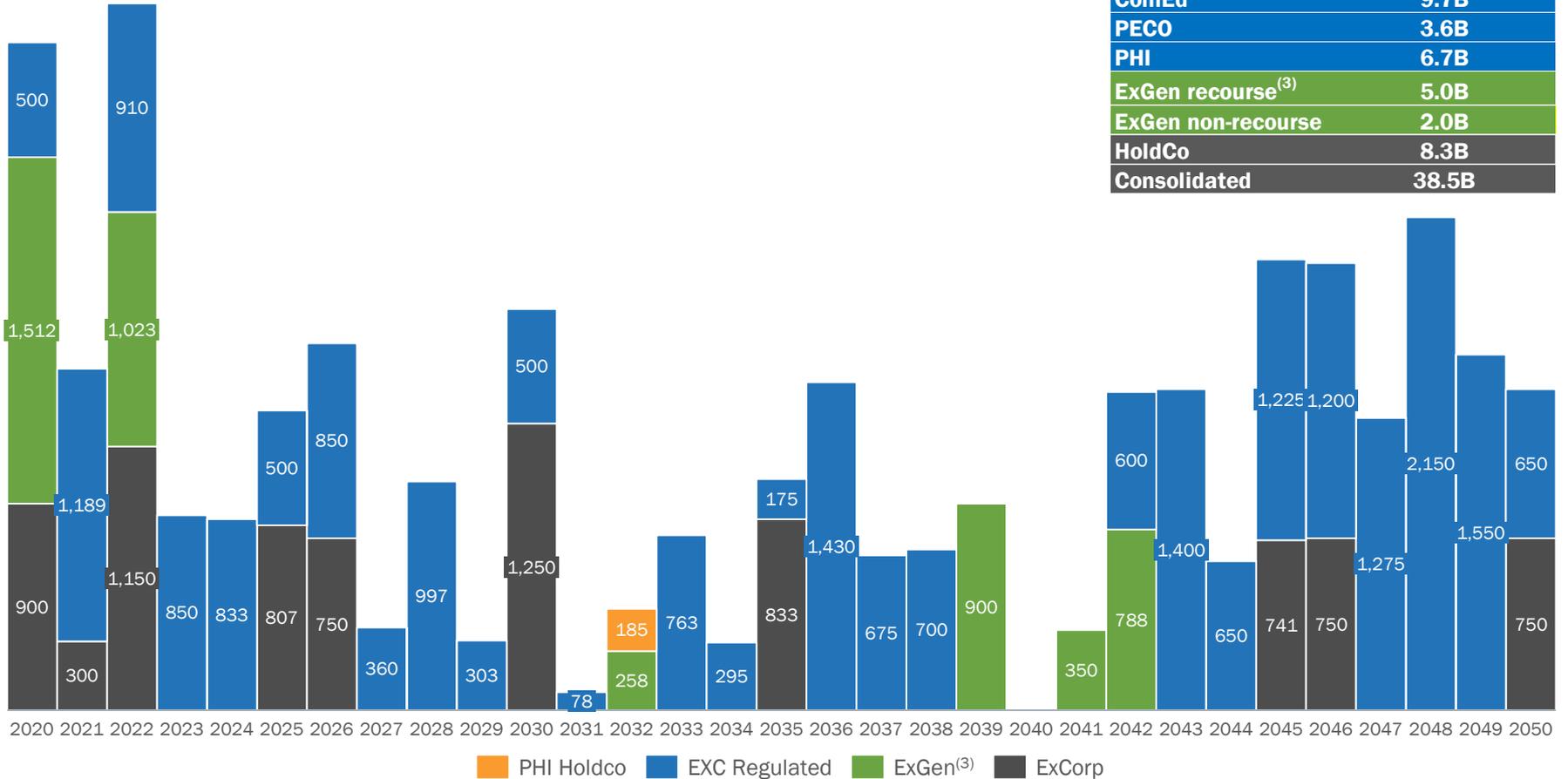
(3) ExGen received ~\$500M in the initial capital raise under the AR securitization facility. The facility has a maximum borrowing of \$750M.

(4) Corporate and ComEd maturities are due in June and August, respectively

(5) In February 2020, PHI successfully priced a \$500M private placement issuance that includes a delayed draw feature. To date, \$150M at Pepco has been drawn from investors and the balance across PHI will be drawn in Q2 and Q3 of 2020.

# Exelon Debt Maturity Profile<sup>(1,2)</sup>

As of 4/30/2020  
(\$M)

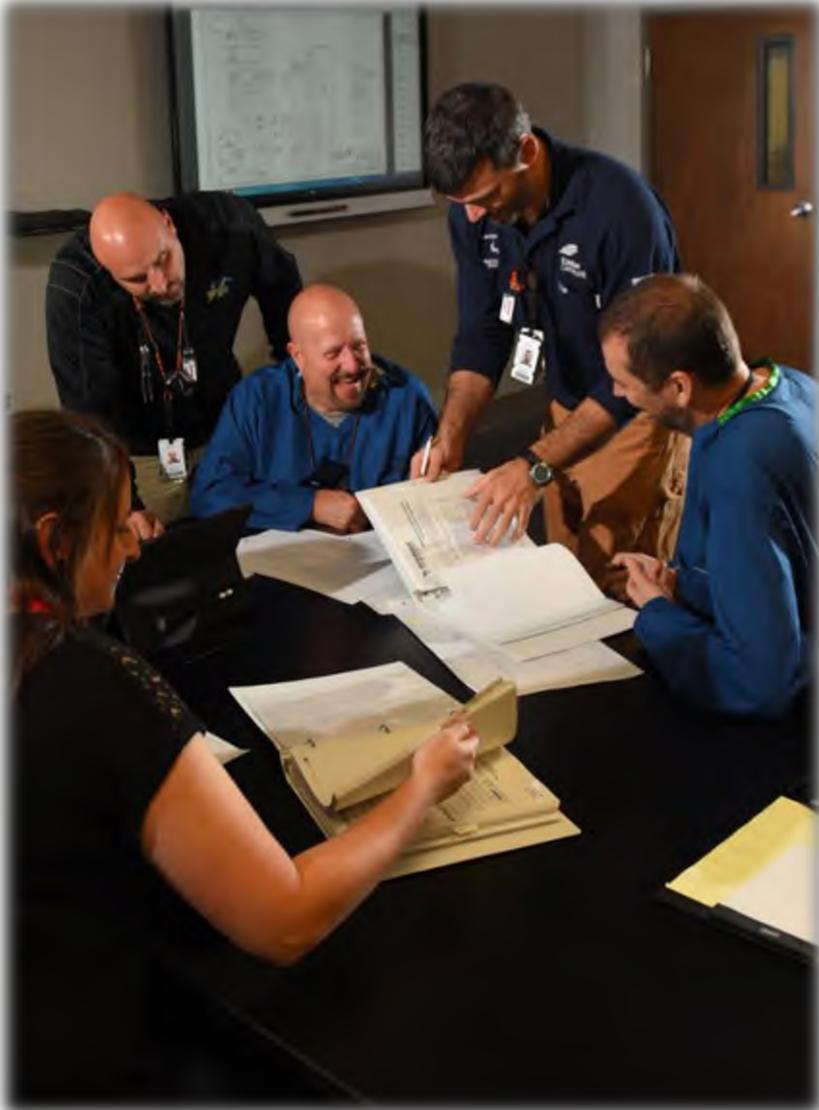


**Exelon's weighted average LTD maturity is approximately 15 years**

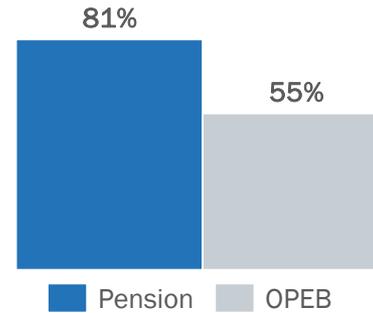
(1) Maturity profile is based on long-term debt outstanding as of 4/30/20 and excludes non-recourse debt, securitized debt, capital leases, fair value adjustments, unamortized debt issuance costs and unamortized discount/premium  
 (2) Long-term debt balances reflect Q1 2020 10Q GAAP financials, which include items listed in footnote 1 and the following adjustments: closing (4/1/20) of HoldCo's \$2B issuance in 10 YR (\$1.25B) and 30 YR (\$0.75B) maturities and repayment of ExGen's \$1.5B of borrowings (4/3/20) under its revolving credit facility  
 (3) Includes legacy CEG debt of \$550M and \$258M in 2020 and 2032; and tax-exempt bonds of \$412M in 2020



# Pension and OPEB Plans are Sufficiently Funded



- Annual \$500M contribution made in Q1; no additional funding is expected in 2020
- Rate of return on assets and changes to the discount rate is not expected to impact 2020 earnings
- Pension and OPEB costs re-measured at year-end
- Costs are recovered through the formula rate in IL and base rates in all other jurisdictions<sup>(1)</sup>
- Funded status of pension and OPEB plans<sup>(2)</sup>



- Conservative and diversified pension and OPEB asset allocations<sup>(2)</sup>

### Pension

33% Equity  
 44% Fixed Income  
 23% Alternative

### OPEB

46% Equity  
 32% Fixed Income  
 22% Alternative

(1) PECO does not recover pension costs, but recovers pension contributions

(2) Allocations and funding status as of YE 2019 with next re-measurement planned for YE 2020; Alternative investments include private equity, hedge funds, real estate and private credit

# Exelon Utilities

# Utility Highlights

						
<b>2019 Electric Customer Mix (Percent of Revenues)<sup>(1)</sup></b>						
Commercial & Industrial (C&I)	34%	25%	29%	44%	25%	28%
Residential	50%	64%	56%	45%	56%	53%
Public Authorities/Other	16%	11%	15%	12%	19%	19%
<b>2019 Electric Customer Mix (Percent of Volumes)<sup>(1)</sup></b>						
Commercial & Industrial (C&I)	68%	61%	56%	64%	56%	54%
Residential	31%	37%	43%	33%	44%	45%
Public Authorities/Other	1%	2%	1%	3%	0%	1%
<b>Decoupled<sup>(2)</sup></b>	✓		✓	✓	MD Only ✓	
<b>Bad Debt Tracker</b>	✓					✓
<b>Capital Recovery Mechanism</b>	✓	✓	✓	DC Only ✓	DE Only ✓	✓
<b>COVID Expense Regulatory Asset<sup>(3)</sup></b>	✓		✓	✓	MD Only ✓	
<b>Formula Rate or Multi-Year Rate Plan (Distribution)<sup>(4)</sup></b>	✓		✓	MD Only ✓	MD Only ✓	
<b>Forward-Looking Test Year</b>		✓				
<b>Formula Rate (Transmission)</b>	✓	✓	✓	✓	✓	✓

(1) Percent of revenues and volumes by customer class may not sum due to rounding

(2) ComEd's formula rate includes a mechanism that eliminates volumetric risk; certain classes for BGE, DPL MD and Pepco are not decoupled

(3) Under EIMA statute, ComEd is able record expenses greater than \$10 million resulting from a one-time event to a regulatory asset and amortize over 5 years

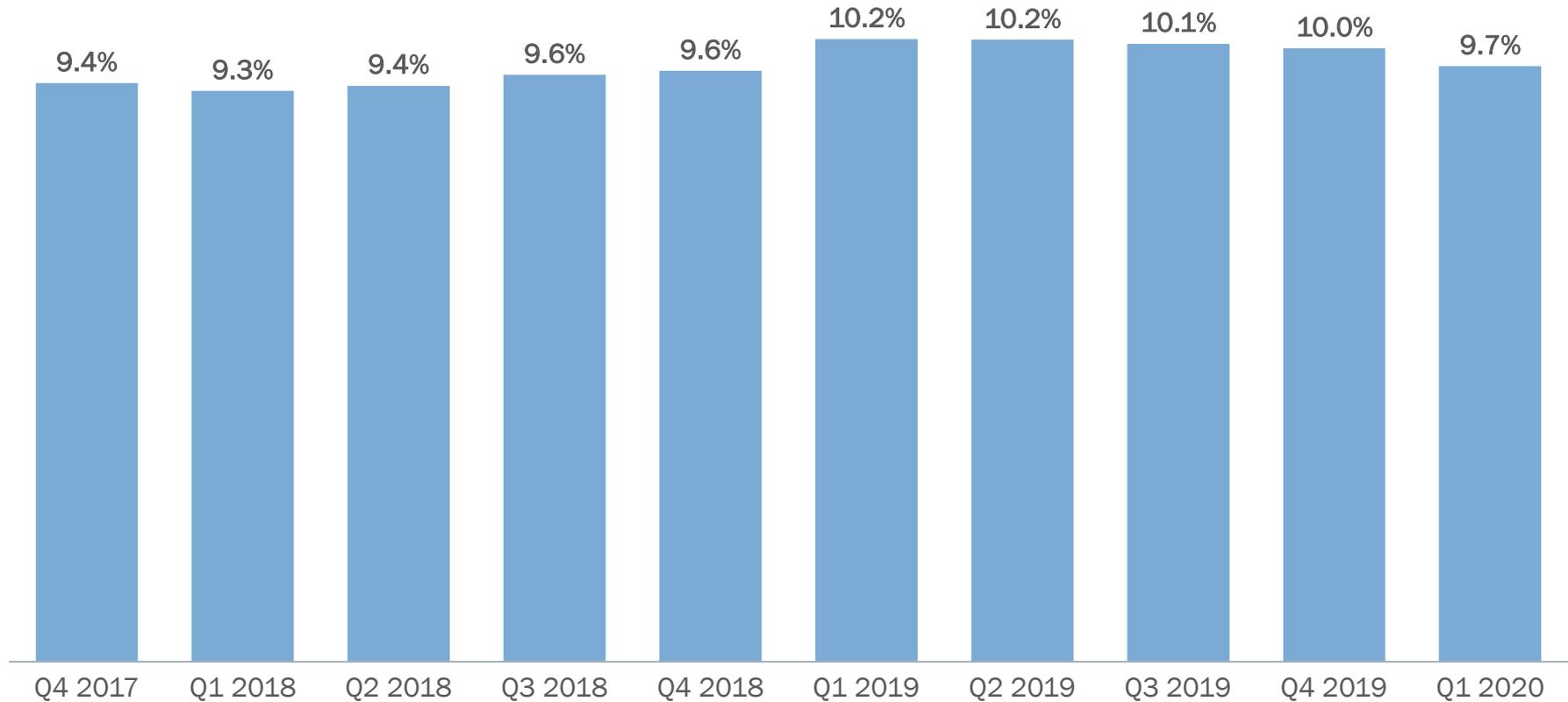
(4) Maryland PSC approved alternative rate making allowing for multi-year rate plans, but no filings to date. Pepco DC filed a Multi-Year Rate Plan in May 2019 and expects an order by Q4 2020.

# Bad Debt and COVID-19 Cost Recovery

	Existing Bad Debt Recovery	New COVID-19 Cost Recovery
<b>Illinois</b> ComEd	<ul style="list-style-type: none"> <li>Rider UF is an uncollectible rider which enables the recovery of current year actual bad debt costs resulting in no earnings impact; cash recovery of 2020 actual bad debt costs is expected in June 2021 – May 2022</li> </ul>	<ul style="list-style-type: none"> <li>The Commission has asked that all incremental COVID-19 expenses be tracked</li> <li>Due to the Formula rate, incremental O&amp;M costs will have no earnings impact; cash recovery expected in 2022. Under EIMA statute, ComEd is able record expenses greater than \$10 million resulting from a one-time event to a regulatory asset and amortize over 5 years.</li> </ul>
<b>Maryland</b> BGE Pepco MD DPL MD	<ul style="list-style-type: none"> <li>Recover through rate cases</li> </ul>	<ul style="list-style-type: none"> <li>On April 9, the MD PSC issued an order authorizing the creation of a regulatory asset to track the incremental COVID-19 costs that were prudently incurred beginning on March 16, 2020 (when the state of emergency was declared in MD)</li> <li>This will allow for assessment of recovery of incremental bad debt or atypical costs related to COVID-19</li> </ul>
<b>DC</b> Pepco DC	<ul style="list-style-type: none"> <li>Recover through rate cases</li> </ul>	<ul style="list-style-type: none"> <li>On April 15, the DC PSC issued an order authorizing the creation of a regulatory asset to track the incremental COVID-19 costs that were prudently incurred beginning March 11, 2020 (when the state of emergency was declared in DC) through 15 days after it ends</li> <li>This will allow for assessment of recovery of incremental bad debt or atypical costs related to COVID-19</li> </ul>
<b>New Jersey</b> ACE	<ul style="list-style-type: none"> <li>Societal Benefit Charge Rider enables deferral of bad debt expense to the balance sheet so there is no earning impact; cash recovery is expected starting in 2021</li> </ul>	<ul style="list-style-type: none"> <li>Currently engaged with the Commissions and other key stakeholders regarding potential recovery of costs, but no actions to date</li> </ul>
<b>Pennsylvania</b> PECO	<ul style="list-style-type: none"> <li>Recover through rate cases</li> </ul>	<ul style="list-style-type: none"> <li>Currently engaged with the Commission and other key stakeholders regarding potential recovery of costs, but no actions to date</li> </ul>
<b>Delaware</b> DPL DE	<ul style="list-style-type: none"> <li>Recover through rate cases</li> </ul>	<ul style="list-style-type: none"> <li>Currently engaged with the Commission and other key stakeholders regarding potential recovery of costs, but no actions to date</li> </ul>

# Exelon Utilities Trailing Twelve Month Earned ROEs\*

## Exelon Utilities' Consolidated Trailing Twelve Month Earned ROEs\*



**Exelon Utilities' Consolidated TTM Earned ROE\* has improved from the lower-end to the upper-end of our 9-10% target range despite pressures from declining interest rates**

Note: Represents the twelve-month periods ending March 31, 2018-2020, December 31, 2017-2019, September 30, 2018-2019 and June 30, 2018-2019. Earned ROEs\* represent weighted average across all lines of business (Electric Distribution, Gas Distribution, and Electric Transmission). Q3 2019, Q2 2019, Q1 2019, Q4 2018, Q3 2018, Q2 2018, Q1 2018 and Q4 2017 TTM ROEs\* for Consolidated EU were changed from 10.1%, 10.2%, 10.2%, 9.7%, 9.6%, 9.4%, 9.4% and 9.5%, respectively, to 10.1%, 10.2%, 10.2%, 9.6%, 9.6%, 9.4%, 9.3% and 9.4%, respectively, to reflect the correction of an error at PHI

# Exelon Utilities' Distribution Rate Case Updates

## Rate Case Schedule and Key Terms

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Revenue Requirement	Requested ROE / Equity Ratio	Expected Order
<b>Pepco DC Electric</b>			IT	RT			EH	IB	RB	FO			\$147.2M <sup>(1,2)</sup> 3-Year MYP	10.30% / 50.68%	Q4 2020
<b>DPL MD Electric</b>		IT	RT	EH	IB		FO						\$17.5M <sup>(1)</sup>	10.30% / 50.53%	Jul 16, 2020
<b>DPL DE Gas</b>		CF					IT	RT			EH	IB	\$9.1M <sup>(1,3)</sup>	10.30% / 50.37%	Q1 2021
<b>DPL DE Electric</b>			CF										\$23.7M <sup>(1,4)</sup>	10.30% / 50.37%	Q1 2021
<b>ComEd<sup>(5)</sup></b>				CF		IT	RT	EH	IB	RB			(\$11.5M) <sup>(1)</sup>	8.38% / 48.61%	Dec 2020

<b>CF</b> Rate case filed	<b>RT</b> Rebuttal testimony	<b>IB</b> Initial briefs	<b>FO</b> Final commission order
<b>IT</b> Intervenor direct testimony	<b>EH</b> Evidentiary hearings	<b>RB</b> Reply briefs	<b>SA</b> 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) Reflects 3-year cumulative multi-year plan. Company proposed incremental revenue requirement increases of \$77.3M, \$36.8M and \$33.1M with rates effective November 1, 2020, January 1, 2021 and January 1, 2022, respectively.
- (3) Requested revenue requirement excludes the transfer of \$4.2M of revenues from the Distribution System Improvement Charge (DSIC) capital tracker into base distribution rates. As permitted by Delaware law, Delmarva Power will implement full allowable rates on September 21, 2020, subject to refund.
- (4) Requested revenue requirement excludes the transfer of \$3.2M of revenues from the Distribution System Improvement Charge (DSIC) capital tracker into base distribution rates. As permitted by Delaware law, Delmarva Power will implement full allowable rates on October 6, 2020, subject to refund.
- (5) Anticipated schedule, actual dates will be determined by ALJ at status hearing

# Pepco DC (Electric) Distribution Rate Case Filing

Multi-Year Plan Case Filing Details		Notes
<b>Formal Case No.</b>	1156	<ul style="list-style-type: none"> <li>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</li> <li>Size of ask is driven by continued investments in electric distribution system to maintain and increase reliability and customer service</li> <li>MYP proposes five Performance Incentive Mechanisms (PIMs) focused on system reliability, customer service and interconnection Distributed Energy Resources (DER)</li> </ul>
<b>Test Year</b>	January 1 – December 31	
<b>Test Period</b>	2020, 2021, 2022	
<b>Proposed Common Equity Ratio</b>	50.68%	
<b>Proposed Rate of Return</b>	ROE: 10.30%; ROR: 7.69%	
<b>2020-2022 Proposed Rate Base (Adjusted)</b>	\$2.2B, \$2.4B, \$2.6B	
<b>2020-2022 Requested Revenue Requirement Increase<sup>(1,2)</sup></b>	\$77.3M, \$36.8M, \$33.1M	
<b>2020-2022 Residential Total Bill % Increase<sup>(2)</sup></b>	6.7%, 4.1%, 3.6%	

## Detailed Rate Case Schedule

	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Filed rate case	▲ 5/30/2019																			
Intervenor testimony	▲ 3/6/2020																			
Rebuttal testimony	▲ 4/8/2020																			
Evidentiary hearings	■ 6/29/2020 - 7/3/2020																			
Initial briefs	▲ 8/26/2020																			
Reply briefs	▲ 9/10/2020																			
Commission order expected	Q4 2020 																			

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

(2) Company proposed incremental revenue requirement increases with rates effective November 1, 2020, January 1, 2021 and January 1, 2022, respectively

# Delmarva MD (Electric) Distribution Rate Case Filing

Rate Case Filing Details		Notes
<b>Case No.</b>	9630	<ul style="list-style-type: none"> <li>December 5, 2019, Delmarva Power filed an application with the Maryland Public Service Commission (MDPSC) seeking an increase in electric distribution base rates</li> <li>Size of ask is driven by continued investments in electric distribution system to maintain and increase reliability and customer service</li> </ul>
<b>Test Year</b>	September 1, 2018 – August 31, 2019	
<b>Test Period</b>	12 months actual	
<b>Proposed Common Equity Ratio</b>	50.53%	
<b>Proposed Rate of Return</b>	ROE: 10.30%; ROR: 7.19%	
<b>Proposed Rate Base (Adjusted)</b>	\$852.6M	
<b>Requested Revenue Requirement Increase</b>	\$17.5M <sup>(1)</sup>	
<b>Residential Total Bill % Increase</b>	3.3%	

## Detailed Rate Case Schedule

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov
Filed rate case		▲ 12/5/2019											
Intervenor testimony				▲ 2/21/2020									
Rebuttal testimony					▲ 3/20/2020								
Evidentiary hearings							■ 4/27/2020 - 4/28/2020						
Initial briefs							▲ 5/22/2020						
Commission order expected										▲ 7/16/2020			

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

# Delmarva DE (Gas) Distribution Rate Case Filing

Rate Case Filing Details		Notes
<b>Docket No.</b>	20-0150	<ul style="list-style-type: none"> <li>February 21, 2020, Delmarva Power filed an application with the Delaware Public Service Commission (DPSC) seeking an increase in gas distribution base rates</li> <li>Size of ask is driven by continued investments in gas distribution system to maintain and increase reliability and customer service</li> </ul>
<b>Test Year</b>	April 1, 2019 – March 31, 2020	
<b>Test Period</b>	9 months actual + 3 months estimated	
<b>Proposed Common Equity Ratio</b>	50.37%	
<b>Proposed Rate of Return</b>	ROE: 10.30%; ROR: 7.15%	
<b>Proposed Rate Base (Adjusted)</b>	\$415.5M	
<b>Requested Revenue Requirement Increase</b>	\$9.1M <sup>(1,2)</sup>	
<b>Residential Total Bill % Increase</b>	5.7%	

## Detailed Rate Case Schedule

	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr
Filed rate case	▲ 2/21/2020														
Intervenor testimony	▲ 7/9/2020														
Rebuttal testimony	▲ 8/25/2020														
Evidentiary hearings	■ 11/19/2020 - 11/20/2020														
Initial briefs	▲ 12/18/2020														
Reply briefs	▲ 1/6/2021														
Commission order expected	Q1 2021 														

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

(2) Requested revenue requirement excludes the transfer of \$4.2M of revenues from the Distribution System Improvement Charge (DSIC) capital tracker into base distribution rates. As permitted by Delaware law, Delmarva Power will implement full allowable rates on September 21, 2020, subject to refund.

# Delmarva DE (Electric) Distribution Rate Case Filing

Rate Case Filing Details		Notes
<b>Docket No.</b>	20-0149	<ul style="list-style-type: none"> <li>March 6, 2020, Delmarva Power filed an application with the Delaware Public Service Commission (DPSC) seeking an increase in electric distribution base rates</li> <li>Size of ask is driven by continued investments in electric distribution system to maintain and increase reliability and customer service</li> </ul>
<b>Test Year</b>	April 1, 2019 – March 31, 2020	
<b>Test Period</b>	9 months actual + 3 months estimated	
<b>Proposed Common Equity Ratio</b>	50.37%	
<b>Proposed Rate of Return</b>	ROE: 10.30%; ROR: 7.15%	
<b>Proposed Rate Base (Adjusted)</b>	\$901.3M	
<b>Requested Revenue Requirement Increase</b>	\$23.7M <sup>(1,2)</sup>	
<b>Residential Total Bill % Increase</b>	3.4%	

## Detailed Rate Case Schedule

	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr
Filed rate case		▲ 3/6/2020													
Intervenor testimony															
Rebuttal testimony															
Evidentiary hearings															
Initial briefs															
Reply briefs															
Commission order expected												Q1 2021			

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

(2) Requested revenue requirement excludes the transfer of \$3.2M of revenues from the Distribution System Improvement Charge (DSIC) capital tracker into base distribution rates. As permitted by Delaware law, Delmarva Power will implement full allowable rates on October 6, 2020, subject to refund.

# ComEd Distribution Rate Case Filing

Rate Case Filing Details		Notes
<b>Docket No.</b>	20-0393	<ul style="list-style-type: none"> <li>April 16, 2020, ComEd filed its annual distribution formula rate update with the Illinois Commerce Commission seeking a decrease to distribution base rates</li> </ul>
<b>Test Year</b>	January 1, 2019 – December 31, 2019	
<b>Test Period</b>	2019 Actual Costs + 2020 Projected Plant Additions	
<b>Proposed Common Equity Ratio</b>	48.61%	
<b>Proposed Rate of Return</b>	ROE: 8.38%; ROR: 6.28%	
<b>Proposed Rate Base (Adjusted)</b>	\$12,051M	
<b>Requested Revenue Requirement Decrease</b>	(\$11.5M) <sup>(4)</sup>	
<b>Residential Total Bill % Decrease</b>	(3.1%)	

## Detailed Rate Case Schedule<sup>(2)</sup>

	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb
Filed rate case		▲ 4/16/2020										
Intervenor testimony				■ 6/2020								
Rebuttal testimony					■ 7/2020							
Evidentiary hearings						■ 8/2020						
Initial briefs							■ 9/2020					
Reply briefs							■ 9/2020					
Commission order expected										■ 12/2020		

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

(2) Anticipated schedule, actual dates will be determined by ALJ at status hearing

# **Exelon Generation Disclosures**

**March 31, 2020**

# Load Volume Impact on Constellation

## Key Drivers

Constellation is impacted in several ways when customer energy usage deviates from expectations

- 1. Unit Margin:** unitized margins can realize higher or lower than forecast as a result of actual load relative to expectations.
- 2. Commodity Value:** customer contracts can become “in” or “out-of-the-money” over time based on changes to underlying power prices. If a customer consumes less than forecast, that unconsumed generation must be sold into the market at prices that may be lower than the initial contract price.
- 3. Collection of Fixed Charges:** some load serving costs are fixed dollar amounts unitized over expected quantities and collected on a \$/MWh basis. When customers consume more or less than expected, Constellation over or under-collects revenue against these fixed costs.

Fixed charges vary significantly by region, but are often largest in markets with higher capacity costs such as PJM and New England

## Sample Price Buildup<sup>(1)</sup>

Sample Price Buildup (\$/MWh)	
	<u>\$/MWh</u>
<b>Energy<sup>(2)</sup></b>	<b>\$28.00</b>
<b>Fixed Charges (i.e. Capacity)</b>	<b>\$7.00</b>
<b>Ancillaries</b>	<b>\$5.00</b>
<b>Other</b>	<b>\$4.00</b>
<b>Total Cost to Serve</b>	<b>\$44.00</b>
<b>Unit Margin</b>	<b>\$2.00 - \$4.00</b>
<b>Contract Price</b>	<b>\$46.00 - \$48.00</b>

(1) Sample Price Buildup is for illustrative purposes only; does not reflect true customer rates and charges

(2) Energy is subject to market movements

# 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



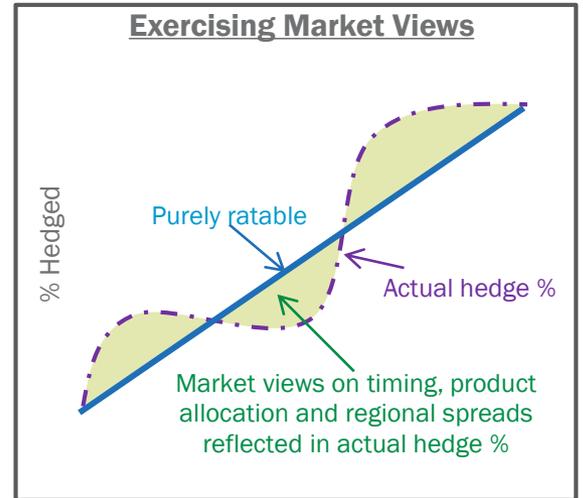
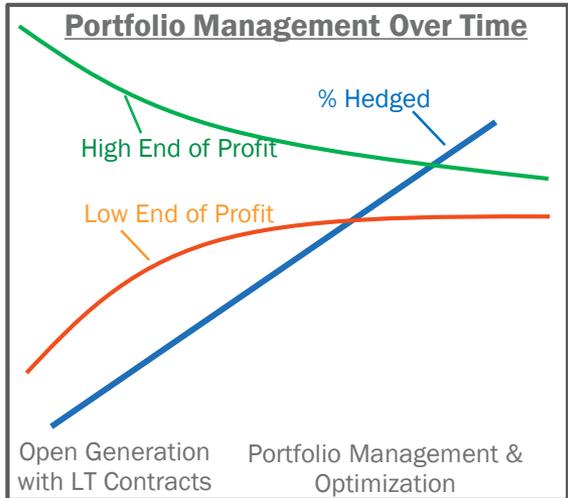
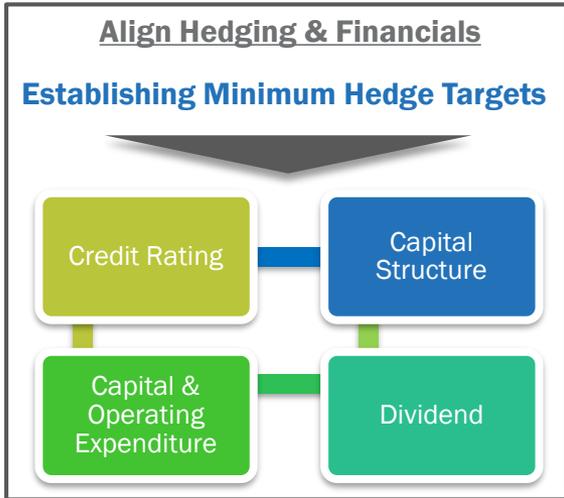
### Three-Year Ratable Hedging

- 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

## Gross margin\* linked to power production and sales

## Gross margin\* from other business activities

**Open Gross Margin\***

- 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<sup>(1)</sup>)

**Capacity and ZEC Revenues**

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

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

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

**“Power” New Business**

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

**“Non Power” Executed**

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

**“Non Power” New Business**

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

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

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

(1) Hedged gross margins\* for South, West, 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

<b>Gross Margin Category (\$M)<sup>(1)</sup></b>	<b>March 31, 2020</b>	
	<b>2020</b>	<b>2021</b>
Open Gross Margin (including South, West, New England & Canada hedged GM) <sup>(2)</sup>	\$2,850	\$3,350
Capacity and ZEC Revenues <sup>(2)</sup>	\$1,900	\$1,850
Mark-to-Market of Hedges <sup>(2,3)</sup>	\$1,500	\$450
Power New Business / To Go	\$300	\$650
Non-Power Margins Executed	\$300	\$200
Non-Power New Business / To Go	\$150	\$300
<b>Total Gross Margin*<sup>(4)</sup></b>	<b>\$7,000</b>	<b>\$6,800</b>
<b>Reference Prices<sup>(4)</sup></b>	<b>2020</b>	<b>2021</b>
Henry Hub Natural Gas (\$/MMBtu)	\$1.98	\$2.48
Midwest: NiHub ATC prices (\$/MWh)	\$18.89	\$22.08
Mid-Atlantic: PJM-W ATC prices (\$/MWh)	\$21.15	\$26.45
ERCOT-N ATC Spark Spread (\$/MWh) <i>HSC Gas, 7.2HR, \$2.50 VOM</i>	\$12.33	\$10.41
New York: NY Zone A (\$/MWh)	\$18.29	\$24.22

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

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

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

(4) Based on March 31, 2020 market conditions

# ExGen Disclosures

**March 31, 2020**

<b>Generation and Hedges</b>	<b>2020</b>	<b>2021</b>
<b>Expected Generation (GWh)<sup>(1)</sup></b>	<b>185,100</b>	<b>181,300</b>
Midwest	97,100	95,500
Mid-Atlantic <sup>(2)</sup>	47,400	48,000
ERCOT	25,100	21,200
New York <sup>(2)</sup>	15,500	16,600
<b>% of Expected Generation Hedged<sup>(3)</sup></b>	<b>89%-92%</b>	<b>70%-73%</b>
Midwest	91%-94%	72%-75%
Mid-Atlantic <sup>(2)</sup>	88%-91%	73%-76%
ERCOT	87%-90%	61%-64%
New York <sup>(2)</sup>	75%-78%	59%-62%
<b>Effective Realized Energy Price (\$/MWh)<sup>(4)</sup></b>		
Midwest	\$27.50	\$26.00
Mid-Atlantic <sup>(2)</sup>	\$36.00	\$31.50
ERCOT <sup>(5)</sup>	\$8.00	\$8.50
New York <sup>(2)</sup>	\$33.00	\$28.00

(1) Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Expected generation assumes 14 refueling outages in 2020 and 13 in 2021 at Exelon-operated nuclear plants and Salem. Expected generation assumes capacity factors of 94.0% and 94.2% in 2020 and 2021, respectively at Exelon-operated nuclear plants, at ownership. These estimates of expected generation in 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

# ExGen Hedged Gross Margin\* Sensitivities

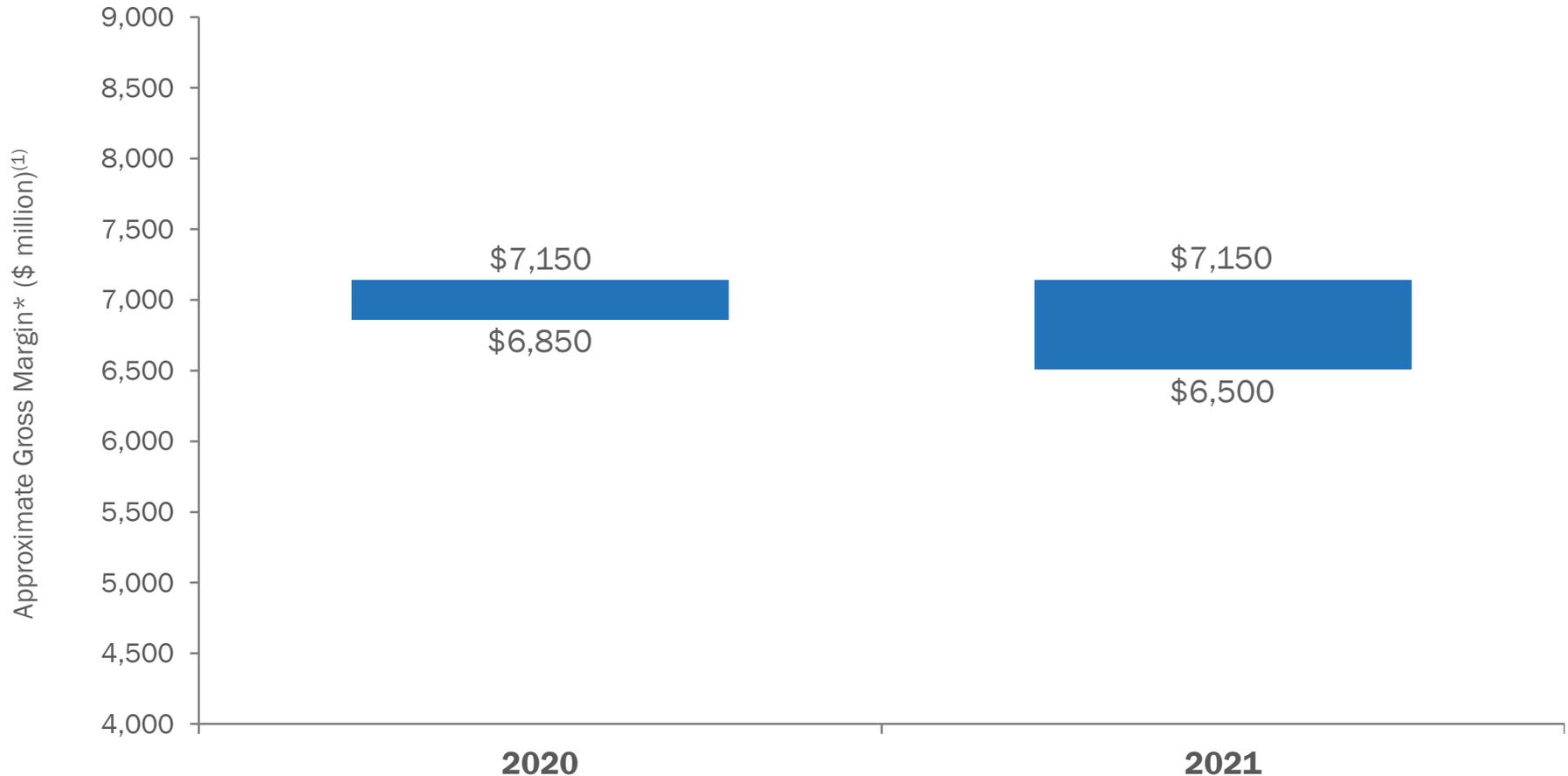
**March 31, 2020**

<b>Gross Margin* Sensitivities (with existing hedges)<sup>(1,2)</sup></b>	<b>2020</b>	<b>2021</b>
<b>Henry Hub Natural Gas (\$/MMBtu)</b>		
+ \$1/MMBtu	\$55	\$350
- \$1/MMBtu	\$(215)	\$(355)
<b>NiHub ATC Energy Price</b>		
+ \$5/MWh	\$30	\$110
- \$5/MWh	\$(30)	\$(110)
<b>PJM-W ATC Energy Price</b>		
+ \$5/MWh	\$5	\$50
- \$5/MWh	\$(10)	\$(70)
<b>NYPP Zone A ATC Energy Price</b>		
+ \$5/MWh	\$20	\$30
- \$5/MWh	\$(20)	\$(30)
<b>Nuclear Capacity Factor</b>		
+/- 1%	+/- \$15	+/- \$25

(1) Based on March 31, 2020 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

(2) These sensitivities do not capture changes to underlying assumptions for COVID-19

# 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 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 March 31, 2020. Gross Margin\* Upside/Risk based on commodity exposure which includes open generation and all committed transactions.

# Illustrative Example of Modeling Exelon Generation 2021 Total Gross Margin\*

ZECJ-FIN-21

PUBLIC

Row	Item	Midwest	Mid-Atlantic	ERCOT	New York
(A)	Start with fleet-wide open gross margin	←————— \$3.35 billion —————→			
(B)	Capacity and ZEC	←————— \$1.85 billion —————→			
(C)	Expected Generation (TWh)	95.5	48.0	21.2	16.6
(D)	Hedge % (assuming mid-point of range)	73.5%	74.5%	62.5%	60.5%
(E=C*D)	Hedged Volume (TWh)	70.2	35.8	13.3	10.0
(F)	Effective Realized Energy Price (\$/MWh)	\$26.00	\$31.50	\$8.50	\$28.00
(G)	Reference Price (\$/MWh)	\$22.08	\$26.45	\$10.41	\$24.22
(H=F-G)	Difference (\$/MWh)	\$3.92	\$5.05	(\$1.91)	\$3.78
(I=E*H)	Mark-to-Market value of hedges (\$ million) <sup>(1)</sup>	\$275	\$180	(\$25)	\$40
(J=A+B+I)	Hedged Gross Margin (\$ million)	\$5,650			
(K)	Power New Business / To Go (\$ million)	\$650			
(L)	Non-Power Margins Executed (\$ million)	\$200			
(M)	Non-Power New Business / To Go (\$ million)	\$300			
<b>(N=J+K+L+M)</b>	<b>Total Gross Margin *</b>	<b>\$6,800 million</b>			

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

# Additional ExGen Modeling Data

<b>Total Gross Margin Reconciliation (in \$M)<sup>(1)</sup></b>	<b>2020</b>	<b>2021</b>
<b>Revenue Net of Purchased Power and Fuel Expense<sup>*(2,3)</sup></b>	<b>\$7,375</b>	<b>\$7,225</b>
Other Revenues <sup>(4)</sup>	\$(150)	\$(150)
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses	\$(225)	\$(275)
<b>Total Gross Margin* (Non-GAAP)</b>	<b>\$7,000</b>	<b>\$6,800</b>

<b>Key ExGen Modeling Inputs (in \$M)<sup>(1,5)</sup></b>	<b>2020</b>	<b>2021</b>
Other <sup>(6)</sup>	\$200	\$125
Adjusted O&M <sup>*(7)</sup>	\$(4,100)	\$(4,150)
Taxes Other Than Income (TOTI) <sup>(8)</sup>	\$(375)	\$(375)
Depreciation & Amortization*	\$(1,025)	\$(1,075)
Interest Expense	\$(325)	\$(325)
<b>Effective Tax Rate</b>	<b>20.0%</b>	<b>23.0%</b>

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

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

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

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

(5) ExGen O&M, TOTI and 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

(7) 2020 and 2021 Adjusted O&M\* includes \$150M of non-cash expense related to the increase in the ARO liability due to the passage of time

(8) 2020 and 2021 TOTI excludes gross receipts tax of \$125M

# **Appendix**

# **Reconciliation of Non-GAAP Measures**

# Q1 GAAP EPS Reconciliation

Three Months Ended March 31, 2020	ComEd	PECO	BGE	PHI	ExGen	Other	Exelon
<b>2020 GAAP Earnings (Loss) Per Share</b>	<b>\$0.17</b>	<b>\$0.14</b>	<b>\$0.19</b>	<b>\$0.11</b>	<b>\$0.05</b>	<b>(\$0.06)</b>	<b>\$0.60</b>
Mark-to-market impact of economic hedging activities	-	-	-	-	(0.10)	-	(0.10)
Unrealized losses related to NDT funds	-	-	-	-	0.50	-	0.50
Plant retirements and divestitures	-	-	-	-	0.01	-	0.01
Cost management program	-	-	-	-	0.01	-	0.01
Noncontrolling interests	-	-	-	-	(0.15)	-	(0.15)
<b>2020 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share</b>	<b>\$0.17</b>	<b>\$0.14</b>	<b>\$0.19</b>	<b>\$0.11</b>	<b>\$0.32</b>	<b>(\$0.06)</b>	<b>\$0.87</b>

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

# Q1 GAAP EPS Reconciliation (continued)

Three Months Ended March 31, 2019	ComEd	PECO	BGE	PHI	ExGen	Other	Exelon
<b>2019 GAAP Earnings (Loss) Per Share</b>	<b>\$0.16</b>	<b>\$0.17</b>	<b>\$0.17</b>	<b>\$0.12</b>	<b>\$0.37</b>	<b>(\$0.06)</b>	<b>\$0.93</b>
Mark-to-market impact of economic hedging activities	-	-	-	-	0.03	-	0.03
Unrealized gains related to NDT funds	-	-	-	-	(0.20)	-	(0.20)
Plant retirements and divestitures	-	-	-	-	0.02	-	0.02
Cost management program	-	-	-	-	0.01	-	0.01
Noncontrolling interests	-	-	-	-	0.07	-	0.07
<b>2019 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share</b>	<b>\$0.16</b>	<b>\$0.17</b>	<b>\$0.17</b>	<b>\$0.12</b>	<b>\$0.30</b>	<b>(\$0.06)</b>	<b>\$0.87</b>

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

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- **Exelon's projected 2020 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;
  - Certain costs related to plant retirements;
  - Certain costs incurred to achieve cost management program savings;
  - Other items not directly related to the ongoing operations of the business; and
  - Generation's noncontrolling interest related to CENG exclusion items.

# GAAP to Non-GAAP Reconciliations<sup>(1)</sup>

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

## Exelon FFO Calculation<sup>(2)</sup>

GAAP Operating Income  
 + Depreciation & Amortization  
 = EBITDA  
 - Interest Expense  
 +/- Cash Taxes  
 + Nuclear Fuel Amortization  
 +/- Mark-to-Market Adjustments (Economic Hedges)  
 +/- Other S&P Adjustments  
 = **FFO (a)**

## Exelon Adjusted Debt Calculation<sup>(1)</sup>

Long-Term Debt (including current maturities)  
 + Short-Term Debt  
 + Purchase Power Agreement and Operating Lease Imputed Debt  
 + Pension/OPEB Imputed Debt (after-tax)  
 + AR Securitization Imputed Debt  
 - Off-Credit Treatment of Non-Recourse Debt  
 - Cash on Balance Sheet  
 +/- 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

# GAAP to Non-GAAP Reconciliations<sup>(1)</sup>

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

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

## 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

Consolidated EU Operating TTM ROE Reconciliation (\$M)	Q1 2020	Q4 2019	Q3 2019	Q2 2019	Q1 2019
Net Income (GAAP)	\$2,060	\$2,065	\$2,037	\$2,011	\$1,967
Operating Exclusions	\$31	\$30	\$33	\$31	\$33
Adjusted Operating Earnings	\$2,091	\$2,095	\$2,070	\$2,042	\$1,999
Average Equity	\$21,502	\$20,913	\$20,500	\$20,111	\$19,639
<b>Operating (Non-GAAP) TTM ROE (Adjusted Operating Earnings/Average Equity)</b>	<b>9.7%</b>	<b>10.0%</b>	<b>10.1%</b>	<b>10.2%</b>	<b>10.2%</b>

Consolidated EU Operating TTM ROE Reconciliation (\$M)	Q4 2018	Q3 2018	Q2 2018	Q1 2018	Q4 2017
Net Income (GAAP)	\$1,836	\$1,770	\$1,724	\$1,643	\$1,704
Operating Exclusions	\$32	\$40	\$13	\$32	(\$24)
Adjusted Operating Earnings	\$1,869	\$1,810	\$1,737	\$1,675	\$1,680
Average Equity	\$19,367	\$18,878	\$18,467	\$17,969	\$17,779
<b>Operating (Non-GAAP) TTM ROE (Adjusted Operating Earnings/Average Equity)</b>	<b>9.6%</b>	<b>9.6%</b>	<b>9.4%</b>	<b>9.3%</b>	<b>9.4%</b>

Note: Represents the twelve-month periods ending March 31, 2018-2020, December 31, 2017-2019, September 30, 2018-2019 and June 30, 2018-2019. Earned ROEs\* represent weighted average across all lines of business (Electric Distribution, Gas Distribution, and Electric Transmission). Q3 2019, Q2 2019, Q1 2019, Q4 2018, Q3 2018, Q2 2018, Q1 2018 and Q4 2017 TTM ROEs\* for Consolidated EU were changed from 10.1%, 10.2%, 10.2%, 9.7%, 9.6%, 9.4%, 9.4% and 9.5%, respectively, to 10.1%, 10.2%, 10.2%, 9.6%, 9.6%, 9.4%, 9.3% and 9.4%, respectively, to reflect the correction of an error at PHI

# GAAP to Non-GAAP Reconciliations

2020 Adjusted Cash from Ops Calculation (\$M) <sup>(1)</sup>	BGE	ComEd	PECO	PHI	ExGen	Other	Exelon
Net cash flows provided by operating activities (GAAP)	\$625	\$1,325	\$750	\$975	\$4,600	(\$225)	\$8,050
Other cash from investing activities	-	-	-	-	(\$275)	-	(\$275)
Counterparty collateral activity	-	-	-	-	(\$300)	-	(\$300)
A/R Securitization	-	-	-	-	(\$500)	-	(\$500)
<b>Adjusted Cash Flow from Operations (Non-GAAP)</b>	<b>\$625</b>	<b>\$1,325</b>	<b>\$750</b>	<b>\$975</b>	<b>\$3,525</b>	<b>(\$225)</b>	<b>\$6,975</b>

2020 Cash From Financing Calculation (\$M) <sup>(1)</sup>	BGE	ComEd	PECO	PHI	ExGen	Other	Exelon
Net cash flow provided by financing activities (GAAP)	\$650	\$950	\$375	\$550	(\$2,775)	\$725	\$450
Dividends paid on common stock	\$250	\$500	\$350	\$350	\$1,350	(\$1,300)	\$1,500
A/R Securitization	-	-	-	-	\$500	-	\$500
<b>Financing Cash Flow (Non-GAAP)</b>	<b>\$875</b>	<b>\$1,450</b>	<b>\$700</b>	<b>\$900</b>	<b>(\$925)</b>	<b>(\$575)</b>	<b>\$2,425</b>

Exelon Total Cash Flow Reconciliation <sup>(1)</sup>	2020
<b>GAAP Beginning Cash Balance</b>	<b>\$2,425</b>
Adjustment for Cash Collateral Posted	(\$925)
Adjusted Beginning Cash Balance <sup>(3)</sup>	\$1,500
Net Change in Cash (GAAP) <sup>(2)</sup>	(\$225)
Adjusted Ending Cash Balance <sup>(3)</sup>	\$1,300
Adjustment for Cash Collateral Posted	(\$650)
<b>GAAP Ending Cash Balance</b>	<b>\$650</b>

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

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

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

# GAAP to Non-GAAP Reconciliations

ExGen Adjusted O&M Reconciliation (\$M) <sup>(1)</sup>	2020	2021
<b>GAAP O&amp;M</b>	<b>\$4,700</b>	<b>\$4,750</b>
Decommissioning <sup>(2)</sup>	\$75	\$75
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses <sup>(3)</sup>	(\$225)	(\$275)
O&M for managed plants that are partially owned	(\$425)	(\$425)
Other	(\$50)	-
<b>Adjusted O&amp;M (Non-GAAP)</b>	<b>\$4,100</b>	<b>\$4,150</b>

Note: Items may not sum due to rounding

(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\*