UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

August 2, 2018

Date of Report (Date of earliest event reported)

Commission File Number	Exact Name of Registrant as Specified in Its Charter; State of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	**EXELON CORPORATION** **(a Pennsylvania corporation)** 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (800) 483-3220	23-2990190
333-85496	**EXELON GENERATION COMPANY, LLC** **(a Pennsylvania limited liability company)** 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219
1-1839	**COMMONWEALTH EDISON COMPANY** **(an Illinois corporation)** 440 South LaSalle Street Chicago, Illinois 60605-1028 (312) 394-4321	36-0938600
000-16844	**PECO ENERGY COMPANY** **(a Pennsylvania corporation)** P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
1-1910	**BALTIMORE GAS AND ELECTRIC COMPANY** **(a Maryland corporation)** 2 Center Plaza 110 West Fayette Street Baltimore, Maryland 21201 (410) 234-5000	52-0280210
001-31403	**PEPCO HOLDINGS LLC** **(a Delaware limited liability company)** 701 Ninth Street, N.W. Washington, District of Columbia 20068 (202) 872-2000	52-2297449
001-01072	**POTOMAC ELECTRIC POWER COMPANY** **(a District of Columbia and Virginia corporation)** 701 Ninth Street, N.W. Washington, District of Columbia 20068 (202) 872-2000	53-0127880

001-01405	**DELMARVA POWER & LIGHT COMPANY** **(a Delaware and Virginia corporation)** 500 North Wakefield Drive Newark, Delaware 19702 (202) 872-2000	51-0084283
001-03559	**ATLANTIC CITY ELECTRIC COMPANY** **(a New Jersey corporation)** 500 North Wakefield Drive Newark, Delaware 19702 (202) 872-2000	21-0398280

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether any of the registrants are emerging growth companies as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

Emerging growth company ☐

If an emerging growth company, indicate by check mark if any of the registrants have elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Section 2 - Financial Information
Item 2.02. Results of Operations and Financial Condition.
Section 7 - Regulation FD
Item 7.01. Regulation FD Disclosure.

On August 2, 2018, Exelon Corporation (Exelon) announced via press release its results for the second quarter ended June 30, 2018. A copy of the press release and related attachments is attached hereto as Exhibit 99.1. Also attached as Exhibits 99.2 and 99.3 to this Current Report on Form 8-K are the presentation slides to be used at the second quarter 2018 earnings conference call and the second quarter 2018 infographic. This Form 8-K and the attached exhibits are provided under Items 2.02, 7.01 and 9.01 of Form 8-K and are furnished to, but not filed with, the Securities and Exchange Commission.

Exelon has scheduled the conference call for 9:00 AM CT (10:00 AM ET) on August 2, 2018. The call-in number in the U.S. and Canada is 800-690-3108, and the international call-in number is 973-935-8753. If requested, the conference ID number is 2999525. Media representatives are invited to participate on a listen-only basis. The call will be web-cast and archived on Exelon's Web site: www.exeloncorp.com. (Please select the Investors page.)

Telephone replays will be available until August 16, 2018. The U.S. and Canada call-in number for replays is 855-859-2056, and the international call-in number is 404-537-3406. The conference ID number is 2999525.

Section 9 - Financial Statements and Exhibits
Item 9.01. Financial Statements and Exhibits

(d) Exhibits.

Exhibit No.	Description
99.1	Press release and earnings release attachments
99.2	Earnings conference call presentation slides
99.3	Infographic

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This combined Current Report on Form 8-K is being furnished separately by Exelon, 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). Information contained herein relating to any individual Registrant has been furnished by such Registrant on its own behalf. No Registrant makes any representation as to information relating to any other Registrant.

This report 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 the Registrants include those factors discussed herein, as well as the items discussed in (1) the Registrants' 2017 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 23, Commitments and Contingencies; (2) the Registrants' Second Quarter 2018 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 17, Commitments and Contingencies; 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 report. 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 report.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, each Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

EXELON CORPORATION

/s/ Joseph Nigro

Joseph Nigro
Senior Executive Vice President and Chief Financial Officer
Exelon Corporation

EXELON GENERATION COMPANY, LLC

/s/ Bryan P. Wright

Bryan P. Wright
Senior Vice President and Chief Financial Officer
Exelon Generation Company, LLC

COMMONWEALTH EDISON COMPANY

/s/ Jeanne M. Jones

Jeanne M. Jones
Senior Vice President, Chief Financial Officer and Treasurer
Commonwealth Edison Company

PECO ENERGY COMPANY

/s/ Phillip S. Barnett

Phillip S. Barnett
Senior Vice President, Chief Financial Officer and Treasurer
PECO Energy Company

BALTIMORE GAS AND ELECTRIC COMPANY

/s/ David M. Vahos

David M. Vahos
Senior Vice President, Chief Financial Officer and Treasurer
Baltimore Gas and Electric Company

PEPCO HOLDINGS LLC

/s/ Robert M. Aiken

Robert M. Aiken
Vice President and Controller
Pepco Holdings LLC

POTOMAC ELECTRIC POWER COMPANY

/s/ Robert M. Aiken

Robert M. Aiken
Vice President and Controller
Potomac Electric Power Company

DELMARVA POWER & LIGHT COMPANY

/s/ Robert M. Aiken

Robert M. Aiken
Vice President and Controller
Delmarva Power & Light Company

ATLANTIC CITY ELECTRIC COMPANY

/s/ Robert M. Aiken

Robert M. Aiken
Vice President and Controller
Atlantic City Electric Company

August 2, 2018

EXHIBIT INDEX

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99.3	Infographic

Exhibit 99.1
News Release

Contact: Dan Eggers
Investor Relations
312-394-2345

Paul Adams
Corporate Communications
410-470-4167

EXELON REPORTS SECOND QUARTER 2018 RESULTS

Earnings Release Highlights

- GAAP Net Income of $0.56 per share and Adjusted (non-GAAP) Operating Earnings of $0.71 per share for the second quarter of 2018
- Reaffirming full year 2018 Adjusted Operating Earnings guidance of $2.90 to $3.20 per share
- Strong utility operations with every utility achieving top decile CAIDI performance
- Legislation passed in Pennsylvania and Delaware will support investment in the Utility of the Future
- Customer savings from the Tax Cuts & Jobs Act (TCJA) are now projected to exceed $675 million annually across Exelon's electric and gas distribution and transmission customers
- New Jersey zero emissions certificate (ZEC) legislation signed by Gov. Phil Murphy on May 23, 2018

CHICAGO (August 2, 2018) — Exelon Corporation (NYSE: EXC) today reported its financial results for the second quarter of 2018.

“Exelon’s utility and power businesses performed well operationally and financially in the second quarter. Our strategy to accelerate investment in advanced technology and infrastructure to improve customer service gained momentum as lawmakers in Pennsylvania and Delaware passed legislation that will support our initiatives to create the utility of the future,” said Christopher M. Crane, Exelon’s President and CEO. “In May, New Jersey Gov. Phil Murphy signed legislation creating a zero emissions certificate program that will preserve the state’s emissions-free nuclear power plants and the economic and environmental benefits they provide. Our commitment to the communities we serve remains a core value, with our employees setting a new company record by volunteering more than 18,000 hours in 104 cities across the U.S. as part of National Volunteer Month.”

“Exelon again delivered solid financial results with non-GAAP operating earnings of $0.71 per share, which is above our guidance range of $0.55-$0.65 per share,” said Joseph Nigro, Exelon’s Senior Executive Vice President and CFO. “As we look ahead to the rest of the year, we are on solid footing and will continue to focus on delivering strong operational and financial results for our stakeholders. Exelon remains on track to meet our full-year guidance of $2.90-$3.20 per share and expects to earn $0.80-$0.90 per share in the third quarter.”

Second Quarter 2018

Exelon's GAAP Net Income for the second quarter of 2018 increased to $0.56 per share from $0.10 per share in the second quarter of 2017; Adjusted (non-GAAP) Operating Earnings increased to $0.71 per share in the second quarter of 2018 from $0.56 per share in the second quarter of 2017. For the reconciliations of GAAP Net Income to Adjusted (non-GAAP) Operating Earnings, refer to the tables beginning on page 7.

Adjusted (non-GAAP) Operating Earnings in the second quarter of 2018 primarily reflect higher electric distribution earnings at ComEd, regulatory rate increases at PHI, decreased nuclear outage days, increased capacity prices, the favorable impacts of the Illinois Zero Emission Standard (ZES), realized gains on nuclear decommissioning trust fund investments and tax savings related to the TCJA at Generation, partially offset by lower realized energy prices at Generation.

Operating Company Results[1]

ComEd

ComEd's second quarter of 2018 GAAP Net Income increased to $164 million from $118 million in the second quarter of 2017. ComEd’s Adjusted (non-GAAP) Operating Earnings increased to $164 million for the second quarter of 2018 from $141 million in the second quarter of 2017, primarily reflecting higher electric distribution earnings. Due to revenue decoupling, ComEd's distribution earnings are not affected by actual weather or customer usage patterns.

PECO

PECO’s second quarter of 2018 GAAP Net Income increased to $96 million from $88 million in the second quarter of 2017. PECO’s Adjusted (non-GAAP) Operating Earnings for the second quarter of 2018 increased to $97 million from $89 million in the second quarter of 2017, primarily due to favorable weather conditions and volumes.

Heating degree days were up 46.5 percent relative to the same period in 2017 and were 9.3 percent above normal. Total retail electric deliveries were up 1.4 percent compared with the second quarter of 2017. Natural gas deliveries (including both retail and transportation segments) in the second quarter of 2018 were up 15.7 percent compared with the same period in 2017.

BGE

BGE’s second quarter of 2018 GAAP Net Income increased to $51 million from $45 million in the second quarter of 2017. BGE’s Adjusted (non-GAAP) Operating Earnings for the second quarter of 2018 increased to $52 million from $46 million in the second quarter of 2017, primarily reflecting transmission rate increases. Due to revenue decoupling, BGE's distribution earnings are not affected by actual weather or customer usage patterns.

[1]Exelon’s five business units include ComEd, which consists of electricity transmission and distribution operations in northern Illinois; PECO, which consists of electricity transmission and distribution operations and retail natural gas distribution operations in southeastern Pennsylvania; BGE, which consists of electricity transmission and distribution operations and retail natural gas distribution operations in central Maryland; PHI, which consists of electricity transmission and distribution operations in the District of Columbia and portions of Maryland, Delaware, and New Jersey and retail natural gas distribution operations in northern Delaware; and Generation, which consists of owned and contracted electric generating facilities and wholesale and retail customer supply of electric and natural gas products and services, including renewable energy products and risk management services.

PHI

PHI’s second quarter of 2018 GAAP Net Income increased to $84 million from $66 million in the second quarter of 2017. PHI’s Adjusted (non-GAAP) Operating Earnings for the second quarter of 2018 increased to $86 million from $63 million in the second quarter of 2017, primarily reflecting regulatory rate increases. Due to revenue decoupling, PHI's distribution earnings related to Pepco and DPL Maryland are not affected by actual weather or customer usage patterns.

Generation

Generation's second quarter of 2018 GAAP Net Income increased to $178 million from a Net loss of $235 million in the second quarter of 2017. Generation’s Adjusted (non-GAAP) Operating Earnings for the second quarter of 2018 increased to $331 million from $217 million in the second quarter of 2017, primarily reflecting decreased nuclear outage days, increased capacity prices, the favorable impacts of the Illinois ZES, realized gains on nuclear decommissioning trust fund investments and tax savings related to the TCJA, partially offset by lower realized energy prices.

The proportion of expected generation hedged as of June 30, 2018, was 97 percent to 100 percent for 2018, 71 percent to 74 percent for 2019 and 41 percent to 44 percent for 2020.

Second Quarter and Recent Highlights

- **Tax Cuts and Jobs Act Tax Savings:** The Utility Registrants have made filings with their respective regulators to begin passing back to customers the ongoing annual tax savings resulting from the TCJA. In total, the Utility Registrants project total annual savings of over $675 million across their electric and gas distribution customers and electric transmission customers. There were the following developments related to these filings in the second quarter of 2018:
    - Pursuant to a Pennsylvania Public Utility Commission (PAPUC) order issued on May 17, 2018, to all Pennsylvania utilities without an existing base rate case, PECO began passing back annual tax savings of $4 million to its natural gas distribution customers through a negative surcharge mechanism beginning July 1, 2018.
    - On May 31, 2018, Pepco received an order from the Maryland Public Service Commission (MDPSC) approving a settlement agreement for its 2018 electric distribution rate case, which included the annual ongoing TCJA tax savings and provides a one-time bill credit to customers of approximately $10 million representing the TCJA tax savings from January 1, 2018, through the effective date of June 1, 2018.
    - On June 27, 2018, DPL entered into a settlement agreement with parties in Delaware for its pending electric distribution rate case, which includes the annual ongoing TCJA tax savings and provides a one-time bill credit to customers of approximately $3 million representing the TCJA tax savings from February 1, 2018, through March 17, 2018, when full interim rates were put into effect.
    - ComEd’s, PECO’s, BGE’s, Pepco’s, DPL’s and ACE’s electric transmission formula rate updates effective June 1, 2018, reflect the annual benefit of lower income tax rates from TCJA of $69 million, $20 million, $18 million, $13 million, $12 million and $11 million, respectively.
- **New Jersey Clean Energy Legislation:** On May 23, 2018, Governor Murphy of New Jersey signed new legislation, which became effective immediately, that will establish a ZEC program providing compensation for nuclear plants that demonstrate to the NJBPU that they meet certain requirements,

including that they make a significant contribution to air quality in the state and that their revenues are insufficient to cover their costs and risks. Under the new legislation, the NJBPU will issue ZECs to qualifying nuclear power plants, and the electric distribution utilities in New Jersey, including ACE, will be required to purchase those ZECs and will be allowed to recover the associated costs from their retail distribution customers. The NJBPU has 180 days from the effective date to establish procedures for implementation of the ZEC program and 330 days from the effective date to determine which nuclear power plants are selected to receive ZECs under the program. The quantity of ZECs issued will be determined based on the greater of 40 percent of the total number of MWh of electricity distributed by the public electric distribution utilities in New Jersey in the prior year, or the total number of MWh of electricity generated in the prior year by the selected nuclear power plants. The ZEC price is approximately $10 per MWh during the first 3-year eligibility period. For eligibility periods following the first 3-year eligibility period, the NJBPU has discretion to reduce the ZEC price. Assuming the successful implementation of the New Jersey ZEC program and the selection of Salem as one of the qualifying facilities, the New Jersey ZEC program has the potential to mitigate the heightened risk of earlier retirement for Salem. On the same day, the Governor of New Jersey signed new legislation, which also became effective immediately, that establishes and modifies New Jersey's clean energy and energy efficiency programs and solar and renewable energy portfolio standards.

- **DPL Delaware Electric Distribution Base Rates:** On June 27, 2018, DPL entered into a non-unanimous settlement agreement with the majority of the parties in the proceeding related to its pending electric distribution base rate case. The settlement agreement provides for a net decrease to annual electric distribution base rates of $7 million, which includes annual ongoing TCJA tax savings, and reflects a ROE of 9.7 percent. A decision is expected on the matter in the third quarter of 2018, with a rate refund expected to be issued in the fourth quarter of 2018 if the Delaware Public Service Commission (DPSC) approves the settlement agreement as filed.

- **BGE Maryland Natural Gas Distribution Base Rates:** On June 8, 2018, BGE filed an application with the MDPSC to increase its annual natural gas distribution base rates by $63 million, reflecting a requested ROE of 10.5 percent. BGE expects a decision in the first quarter of 2019 but cannot predict what increase the MDPSC will approve.

- **Delaware Distribution System Investment Charge Legislation:** On June 14, 2018, Governor Carney of Delaware signed new Distribution System Investment Charge (DSIC) legislation, which establishes a system improvement charge that provides a mechanism to recover infrastructure investments, allowing for gradual rate increases and limiting frequency of distribution base rate cases. DPL expects to make its first filing in Delaware in the fourth quarter of 2018, with the new charge effective in the first quarter of 2019. While this legislation is expected to support needed infrastructure investment and allow for more timely recovery of those investments, Exelon, PHI and DPL cannot predict the potential financial impact on Exelon, PHI or DPL.

- **Pennsylvania Alternative Ratemaking Legislation:** On June 28, 2018, Governor Wolf of Pennsylvania signed new legislation, which authorized the PAPUC to review and approve utility-proposed alternative rate designs, including options such as decoupling mechanisms, formula rates, multi-year rate plans, and performance based rates. Exelon and PECO cannot predict the outcome or the potential financial impact, if any, on Exelon or PECO.

- **PJM Transmission Order:** On June 15, 2016, a number of parties, including the Utility Registrants, filed a proposed settlement with FERC to resolve outstanding issues related to cost responsibility for charges to transmission customers for certain transmission facilities that operate at or above 500 kV.

The settlement included provisions for monthly credits or charges related to the periods prior to January 1, 2016, that are expected to be refunded or recovered through PJM wholesale transmission rates through June 2025. On May 31, 2018, FERC issued an order approving the settlement. Pursuant to the order, similar charges for the period January 1, 2016, through June 30, 2018, will also be refunded or recovered through PJM wholesale transmission rates over the subsequent 12-month period. PJM will commence billing the refunds and charges associated with this settlement in August 2018.

Pursuant to the FERC approval of the settlement in the second quarter of 2018, the Utility Registrants recorded gross payables to and receivables from PJM of $135 million and $197 million, respectively, which were offset by regulatory assets and liabilities, resulting in no earnings impact. In addition, Generation recorded a pre-tax charge and payable to PJM of $23 million in the second quarter of 2018.

- **FirstEnergy Solutions:** On July 9, 2018, Generation entered into an agreement to purchase FirstEnergy Solutions Corporation's retail electricity and wholesale load serving contracts and certain other related commodity contracts for an all cash purchase price of $140 million. The transaction is expected to close in the fourth quarter of 2018. The closing of the transaction is subject to certain conditions, including Generation being the winning bidder after a court-supervised Section 363 bankruptcy auction, the approval of the Purchase Agreement by the United States Bankruptcy Court for the Northern District of Ohio following the auction, and the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976. Either party may terminate the Purchase Agreement if the transaction has not been consummated by December 31, 2018.

- **Agreement for Sale and Decommissioning of Oyster Creek:** On July 31, 2018, Generation entered into an agreement with Holtec International (Holtec) and its indirect wholly owned subsidiary, Oyster Creek Environmental Protection, LLC (OCEP), for the sale and decommissioning of Oyster Creek. Generation will transfer to OCEP substantially all the assets associated with Oyster Creek, including assets held in nuclear decommissioning trust (NDT) funds valued at approximately $980 million as of June 30, 2018, along with the assumption of liability for all responsibility for the site, including full decommissioning and ongoing management of spent fuel until the spent fuel is moved offsite. In addition to the assumption of liability for the full decommissioning and ongoing management of spent fuel, other consideration to be received in the transaction is contingent on several factors, including a requirement that Generation deliver a minimum NDT fund balance at closing, subject to adjustment for specific terms that include income taxes that would be imposed on any net unrealized built-in gains and certain decommissioning activities to be performed during the pre-close period after the unit shuts down in the fall of 2018 and prior to the anticipated close of the transaction. Completion of the transaction contemplated by the sale agreement is subject to the satisfaction of several closing conditions, including approval of the license transfer from the NRC and other regulatory approvals, and the receipt of a private letter ruling from the IRS. Generation currently anticipates satisfaction of the closing conditions to occur in the second half of 2019.

- **Mystic Generating Station Early Retirement:** On March 29, 2018, Generation announced it had formally notified grid operator ISO-NE of its plans to early retire its Mystic Generating Station assets on June 1, 2022, absent any interim and long-term solutions for reliability and regional fuel security. On May 1, 2018, ISO-NE made a filing with FERC requesting waiver of certain tariff provisions to allow it to retain Mystic units 8 and 9 for fuel security for the 2022 - 2024 planning years. On May 16, 2018, Generation made a filing with FERC to establish cost-of-service compensation and terms and conditions of service for Mystic units 8 and 9 for the period between June 1, 2022 - May 31,

2024. On July 2, 2018, FERC issued an order denying ISO-NE's May 1, 2018, waiver request on procedural grounds but accepting ISO-NE's conclusions that retirement of Mystic units 8 and 9 could cause a violation of mandatory reliability standards as soon as 2022. Accordingly, FERC ordered ISO-NE to (i) make a filing within 60 days providing for the filing of a short-term cost-of-service agreement to address demonstrated fuel security concerns and (ii) make a filing by July 1, 2019, proposing permanent tariff revisions that would improve its market design to better address regional fuel security concerns. FERC also extended the deadline by which Generation must make a retirement decision for Mystic units 8 and 9 to January 4, 2019. On July 13, 2018, FERC issued an order accepting the cost-of-service agreement for filing, making findings on certain issues and establishing hearing procedures on an expedited schedule. Exelon and Generation cannot predict the final outcome of these proceedings or the potential financial impact, if any, on Exelon or Generation.

- **Nuclear Operations:** Generation's nuclear fleet, including its owned output from the Salem Generating Station and 100 percent of the CENG units, produced 45,723 gigawatt-hours (GWhs) in the second quarter of 2018, compared with 44,065 GWhs in the second quarter of 2017. Excluding Salem, the Exelon-operated nuclear plants at ownership achieved a 93.2 percent capacity factor for the second quarter of 2018, compared with 90.9 percent for the second quarter of 2017. The number of planned refueling outage days in the second quarter of 2018 totaled 94, compared with 125 in the second quarter of 2017. There were 2 non-refueling outage days in the second quarter of 2018, compared with 12 in the second quarter of 2017.

- **Fossil and Renewables Operations:** The Dispatch Match rate for Generation's gas and hydro fleet was 97.8 percent in the second quarter of 2018, compared with 99.0 percent in the second quarter of 2017. The lower performance in the quarter was primarily due to outages at gas cycle units in Massachusetts and Texas.

  Energy Capture for the wind and solar fleet was 95.1 percent in the second quarter of 2018, compared with 95.5 percent in the second quarter of 2017. The lower performance in the quarter was driven by equipment issues at wind farms in Texas.

- **Financing Activities:**

  - On May 23, 2018, ACE entered into two term loan agreements in the aggregate amount of $125 million, which expire on May 22, 2019. Pursuant to the term loan agreements, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.55 percent and all indebtedness thereunder is unsecured.

  - On June 21, 2018, Pepco issued $100 million aggregate principal amount of its First Mortgage Bonds, 4.27 percent due June 15, 2048. Pepco used the proceeds to repay existing indebtedness and for general corporate purposes.

  - On June 21, 2018, DPL issued $200 million in aggregate principal amount of its First Mortgage Bonds, 4.27 percent due June 15, 2048. DPL used the proceeds to repay indebtedness and for general corporate purposes.

GAAP/Adjusted (non-GAAP) Operating Earnings Reconciliation

Adjusted (non-GAAP) Operating Earnings for the second quarter of 2018 do not include the following items (after tax) that were included in reported GAAP Net Income:

(in millions)	Exelon Earnings per Diluted Share	Exelon	ComEd	PECO	BGE	PHI	Generation
2018 GAAP Net Income	**$ 0.56**	**$ 539**	**$ 164**	**$ 96**	**$ 51**	**$ 84**	**$ 178**
Mark-to-Market Impact of Economic Hedging Activities (net of taxes of $23)	(0.07)	(67)	—	—	—	—	(67)
Unrealized Losses Related to Nuclear Decommissioning Trust (NDT) Fund Investments (net of taxes of $77)	0.08	81	—	—	—	—	81
Merger and Integration Costs (net of taxes of $0)	—	1	—	—	—	—	1
Long-Lived Asset Impairments (net of taxes of $11)	0.03	30	—	—	—	—	30
Plant Retirements and Divestitures (net of taxes of $47)	0.14	127	—	—	—	—	127
Cost Management Program (net of taxes of $4, $0, $0, $0 and $4, respectively)	0.01	12	—	1	1	1	9
Change in Environmental Liabilities (net of taxes of $2)	0.01	5	—	—	—	—	5
Reassessment of Deferred Income Taxes (entire amount represents tax expense)	(0.01)	(8)	—	—	—	1	1
Noncontrolling Interests (net of taxes of $7)	(0.04)	(34)	—	—	—	—	(34)
2018 Adjusted (non-GAAP) Operating Earnings	**$ 0.71**	**$ 686**	**$ 164**	**$ 97**	**$ 52**	**$ 86**	**$ 331**

Adjusted (non-GAAP) Operating Earnings for the second quarter of 2017 do not include the following items (after tax) that were included in reported GAAP Net Income:

(in millions)	Exelon Earnings per Diluted Share	Exelon	ComEd	PECO	BGE	PHI	Generation
2017 GAAP Net Income[1]	**$ 0.10**	**$ 95**	**$ 118**	**$ 88**	**$ 45**	**$ 66**	**$ (235)**
Mark-to-Market Impact of Economic Hedging Activities (net of taxes of $72 and $71, respectively)	0.12	113	—	—	—	—	114
Unrealized Gains Related to NDT Fund Investments (net of taxes of $20)	(0.05)	(45)	—	—	—	—	(45)
Amortization of Commodity Contract Intangibles (net of taxes of $8)	0.01	12	—	—	—	—	12
Merger and Integrations Costs (net of taxes of $9, $1 and $7, respectively)	0.02	15	—	—	—	1	12
Merger Commitments (net of taxes of $3)	—	—	—	—	—	(4)	—
Long-Lived Asset Impairments (net of taxes of $172 and $171, respectively)	0.29	268	—	—	—	—	269
Plant Retirements and Divestitures (net of taxes of $42)	0.07	66	—	—	—	—	66
Cost Management Program (net of taxes of $4, $1, $1 and $3, respectively)	0.01	6	—	1	1	—	4
Like-Kind Exchange Tax Position (net of taxes of $66 and $9, respectively)	(0.03)	(26)	23	—	—	—	—
Noncontrolling Interests (net of taxes of $5)	0.02	20	—	—	—	—	20
2017 Adjusted (non-GAAP) Operating Earnings	**$ 0.56**	**$ 524**	**$ 141**	**$ 89**	**$ 46**	**$ 63**	**$ 217**

(1) Certain immaterial prior year amounts in the Registrants' Consolidated Statements of Operations and Comprehensive Income have been recasted to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018.

Note:
Unless otherwise noted, the income tax impact of each reconciling item between GAAP Net Income and Adjusted (non-GAAP) Operating Earnings is based on the marginal statutory federal and state income tax rates for each Registrant, taking into account whether the income or expense item is taxable or deductible, respectively, in whole or in part. For all items except the unrealized gains and losses related to NDT fund investments, the marginal statutory income tax rates for 2018 and 2017 ranged from 26.0 percent to 29.0 percent and 39.0 percent to 41.0 percent, respectively. Under IRS regulations, NDT fund investment returns are taxed at different rates for investments if they are in qualified or non-qualified funds. The effective tax rates for the unrealized gains and losses related to NDT fund investments were 48.9 percent and 31.4 percent for the three months ended June 30, 2018 and 2017, respectively.

Webcast Information

Exelon will discuss second quarter 2018 earnings in a one-hour conference call scheduled for today at 9 a.m. Central Time (10 a.m. Eastern Time). The webcast and associated materials can be accessed at www.exeloncorp.com/investor-relations.

About Exelon

Exelon Corporation (NYSE: EXC) is a Fortune 100 energy company with the largest number of utility customers in the U.S. Exelon does business in 48 states, the District of Columbia and Canada and had 2017 revenue of $33.5 billion. Exelon’s six utilities deliver electricity and natural gas to approximately 10 million customers in Delaware, the District of Columbia, Illinois, Maryland, New Jersey and Pennsylvania through its Atlantic City Electric, BGE, ComEd, Delmarva Power, PECO and Pepco subsidiaries. Exelon is one of the largest competitive U.S. power generators, with more than 32,700 megawatts of nuclear, gas, wind, solar and hydroelectric generating capacity comprising one of the nation’s cleanest and lowest-cost power generation fleets. The company’s Constellation business unit provides energy products and services to approximately 2 million residential, public sector and business customers, including more than two-thirds of the Fortune 100. Follow Exelon on Twitter @Exelon.

Non-GAAP Financial Measures

In addition to net income as determined under generally accepted accounting principles in the United States (GAAP), Exelon evaluates its operating performance using the measure of Adjusted (non-GAAP) Operating Earnings because management believes it represents earnings directly related to the ongoing operations of the business. Adjusted (non-GAAP) Operating Earnings exclude certain costs, expenses, gains and losses and other specified items. This measure is intended to enhance an investor’s overall understanding of period over period operating results and provide an indication of Exelon’s baseline operating performance excluding items that are considered by management to be not directly related to the ongoing operations of the business. In addition, this measure 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. Adjusted (non-GAAP) Operating Earnings is not a presentation defined under GAAP and may not be comparable to other companies’ presentation. The Company has provided the non-GAAP financial measure as supplemental information and in addition to the financial measures that are calculated and presented in accordance with GAAP. Adjusted (non-GAAP) Operating Earnings should not be deemed more useful than, a substitute for, or an alternative to the most comparable GAAP Net Income measures provided in this earnings release and attachments. This press release and earnings release attachments provide reconciliations of adjusted (non-GAAP) Operating Earnings to the most directly comparable financial measures calculated and presented in accordance with GAAP, are posted on Exelon’s website: www.exeloncorp.com, and have been furnished to the Securities and Exchange Commission on Form 8-K on August 2, 2018.

Cautionary Statements Regarding Forward-Looking Information

This press release 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 the Registrants include those factors discussed herein, as well as the items discussed in (1) the Registrants' 2017 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 23, Commitments and Contingencies; (2) the Registrants' Second Quarter 2018 Quarterly Report on Form 10-Q (to be filed on

August 2, 2018) in (a) Part II, Other Information, ITEM 1A. Risk Factors; (b) Part 1, Financial Information, ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 17, Commitments and Contingencies; 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 press release.

Earnings Release Attachments
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EXELON CORPORATION
Consolidating Statements of Operations
(unaudited)
(in millions)

	Three Months Ended June 30, 2018						
	Generation	ComEd	PECO	BGE	PHI (a)	Other (b)	Exelon Consolidated
Operating revenues	$ 4,579	$ 1,398	$ 653	$ 662	$ 1,076	$ (292)	$ 8,076
Operating expenses							
Purchased power and fuel	2,280	477	222	229	381	(274)	3,315
Operating and maintenance	1,418	324	191	176	255	(57)	2,307
Depreciation and amortization	466	231	74	114	180	23	1,088
Taxes other than income	134	79	39	59	107	10	428
Total operating expenses	4,298	1,111	526	578	923	(298)	7,138
Gain on sales of assets and businesses	1	1	—	1	—	1	4
Operating income	282	288	127	85	153	7	942
Other income and (deductions)							
Interest expense, net	(102)	(85)	(32)	(25)	(65)	(64)	(373)
Other, net	29	4	—	4	11	(4)	44
Total other income and (deductions)	(73)	(81)	(32)	(21)	(54)	(68)	(329)
Income (loss) before income taxes	209	207	95	64	99	(61)	613
Income taxes	23	43	(1)	13	15	(27)	66
Equity in losses of unconsolidated affiliates	(5)	—	—	—	—	—	(5)
Net income (loss)	181	164	96	51	84	(34)	542
Net income attributable to noncontrolling interests	3	—	—	—	—	—	3
Net income (loss) attributable to common shareholders	$ 178	$ 164	$ 96	$ 51	$ 84	$ (34)	$ 539

	Three Months Ended June 30, 2017 (c)						
	Generation	ComEd	PECO	BGE	PHI (a)	Other (b)	Exelon Consolidated
Operating revenues	$ 4,216	$ 1,357	$ 630	$ 674	$ 1,074	$ (286)	$ 7,665
Operating expenses							
Purchased power and fuel	2,157	378	197	234	383	(263)	3,086
Operating and maintenance	2,012	377	190	174	269	(77)	2,945
Depreciation and amortization	334	211	71	112	165	22	915
Taxes other than income	140	72	35	56	110	7	420
Total operating expenses	4,643	1,038	493	576	927	(311)	7,366
Gain on sales of assets and businesses	—	—	—	—	1	—	1
Operating (loss) income	(427)	319	137	98	148	25	300
Other income and (deductions)							
Interest expense, net	(129)	(101)	(31)	(26)	(59)	(90)	(436)
Other, net	181	4	2	4	13	(27)	177
Total other income and (deductions)	52	(97)	(29)	(22)	(46)	(117)	(259)
(Loss) income before income taxes	(375)	222	108	76	102	(92)	41
Income taxes	(148)	104	20	31	36	(105)	(62)
Equity in losses of unconsolidated affiliates	(9)	—	—	—	—	—	(9)
Net (loss) income	(236)	118	88	45	66	13	94
Net loss attributable to noncontrolling interests	(1)	—	—	—	—	—	(1)
Net (loss) income attributable to common shareholders	$ (235)	$ 118	$ 88	$ 45	$ 66	$ 13	$ 95

(a) PHI includes the consolidated results of Pepco, DPL and ACE.
(b) Other primarily includes eliminating and consolidating adjustments, Exelon’s corporate operations, shared service entities and other financing and investment activities.
(c) Certain immaterial prior year amounts in the Registrants' Consolidated Statements of Operations and Comprehensive Income have been recasted to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018.

EXELON CORPORATION
Consolidating Statements of Operations
(unaudited)
(in millions)

	Six Months Ended June 30, 2018						
	Generation	ComEd	PECO	BGE	PHI (a)	Other (b)	Exelon Consolidated
Operating revenues	$ 10,090	$ 2,910	$ 1,518	$ 1,639	$ 2,327	$ (715)	$ 17,769
Operating expenses							
Purchased power and fuel	5,573	1,082	555	609	901	(678)	8,042
Operating and maintenance	2,756	638	466	397	563	(129)	4,691
Depreciation and amortization	914	459	149	248	363	46	2,179
Taxes other than income	272	156	79	124	221	22	874
Total operating expenses	9,515	2,335	1,249	1,378	2,048	(739)	15,786
Gain on sales of assets and businesses	54	5	—	1	—	—	60
Operating income	629	580	269	262	279	24	2,043
Other income and (deductions)							
Interest expense, net	(202)	(175)	(64)	(51)	(128)	(125)	(745)
Other, net	(15)	12	2	9	22	(13)	17
Total other income and (deductions)	(217)	(163)	(62)	(42)	(106)	(138)	(728)
Income (loss) before income taxes	412	417	207	220	173	(114)	1,315
Income taxes	32	88	(3)	41	24	(57)	125
Equity in (losses) earnings of unconsolidated affiliates	(12)	—	—	—	—	1	(11)
Net income (loss)	368	329	210	179	149	(56)	1,179
Net income attributable to noncontrolling interests	54	—	—	—	—	—	54
Net income (loss) attributable to common shareholders	$ 314	$ 329	$ 210	$ 179	$ 149	$ (56)	$ 1,125

	Six Months Ended June 30, 2017 (c)						
	Generation	ComEd	PECO	BGE	PHI (a)	Other (b)	Exelon Consolidated
Operating revenues	$ 9,093	$ 2,656	$ 1,426	$ 1,625	$ 2,248	$ (635)	$ 16,413
Operating expenses							
Purchased power and fuel	4,955	713	484	584	845	(596)	6,985
Operating and maintenance	3,503	747	398	357	524	(146)	5,383
Depreciation and amortization	637	419	141	239	332	43	1,811
Taxes other than income	282	144	74	119	221	17	857
Total operating expenses	9,377	2,023	1,097	1,299	1,922	(682)	15,036
Gain on sales of assets and businesses	4	—	—	—	1	—	5
Bargain purchase gain	226	—	—	—	—	—	226
Operating (loss) income	(54)	633	329	326	327	47	1,608
Other income and (deductions)							
Interest expense, net	(228)	(185)	(62)	(54)	(122)	(158)	(809)
Other, net	440	8	3	8	26	(51)	434
Total other income and (deductions)	212	(177)	(59)	(46)	(96)	(209)	(375)
Income (loss) before income taxes	158	456	270	280	231	(162)	1,233
Income taxes	(25)	197	55	111	26	(215)	149
Equity in (losses) earnings of unconsolidated affiliates	(19)	—	—	—	—	1	(18)
Net income	164	259	215	169	205	54	1,066
Net loss attributable to noncontrolling interests	(20)	—	—	—	—	—	(20)
Net income attributable to common shareholders	$ 184	$ 259	$ 215	$ 169	$ 205	$ 54	$ 1,086

(a) PHI consolidated results includes Pepco, DPL and ACE.
(b) Other primarily includes eliminating and consolidating adjustments, Exelon's corporate operations, shared service entities and other financing and investment activities.
(c) Certain immaterial prior year amounts in the Registrants' Consolidated Statements of Operations and Comprehensive Income have been recast to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018.

EXELON CORPORATION
Business Segment Comparative Statements of Operations
(unaudited)
(in millions)

Generation

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	**2017 (a)**	**Variance**	**2018**	**2017 (a)**	**Variance**
Operating revenues	$ 4,579	$ 4,216	$ 363	$ 10,090	$ 9,093	$ 997
Operating expenses						
Purchased power and fuel	2,280	2,157	123	5,573	4,955	618
Operating and maintenance	1,418	2,012	(594)	2,756	3,503	(747)
Depreciation and amortization	466	334	132	914	637	277
Taxes other than income	134	140	(6)	272	282	(10)
Total operating expenses	4,298	4,643	(345)	9,515	9,377	138
Gain on sales of assets and businesses	1	—	1	54	4	50
Bargain purchase gain	—	—	—	—	226	(226)
Operating income (loss)	282	(427)	709	629	(54)	683
Other income and (deductions)						
Interest expense, net	(102)	(129)	27	(202)	(228)	26
Other, net	29	181	(152)	(15)	440	(455)
Total other income and (deductions)	(73)	52	(125)	(217)	212	(429)
Income (loss) before income taxes	209	(375)	584	412	158	254
Income taxes	23	(148)	171	32	(25)	57
Equity in losses of unconsolidated affiliates	(5)	(9)	4	(12)	(19)	7
Net income (loss)	181	(236)	417	368	164	204
Net income (loss) attributable to noncontrolling interests	3	(1)	4	54	(20)	74
Net income (loss) attributable to membership interest	$ 178	$ (235)	$ 413	$ 314	$ 184	$ 130

ComEd

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	**2017 (a)**	**Variance**	**2018**	**2017 (a)**	**Variance**
Operating revenues	$ 1,398	$ 1,357	$ 41	$ 2,910	$ 2,656	$ 254
Operating expenses						
Purchased power	477	378	99	1,082	713	369
Operating and maintenance	324	377	(53)	638	747	(109)
Depreciation and amortization	231	211	20	459	419	40
Taxes other than income	79	72	7	156	144	12
Total operating expenses	1,111	1,038	73	2,335	2,023	312
Gain on sales of assets	1	—	1	5	—	5
Operating income	288	319	(31)	580	633	(53)
Other income and (deductions)						
Interest expense, net	(85)	(101)	16	(175)	(185)	10
Other, net	4	4	—	12	8	4
Total other income and (deductions)	(81)	(97)	16	(163)	(177)	14
Income before income taxes	207	222	(15)	417	456	(39)
Income taxes	43	104	(61)	88	197	(109)
Net income	$ 164	$ 118	$ 46	$ 329	$ 259	$ 70

(a) Certain immaterial prior year amounts in the Registrants' Consolidated Statements of Operations and Comprehensive Income have been recasted to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018.

EXELON CORPORATION
Business Segment Comparative Statements of Operations
(unaudited)
(in millions)

PECO

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017	Variance	2018	2017	Variance
Operating revenues	$ 653	$ 630	$ 23	$ 1,518	$ 1,426	$ 92
Operating expenses						
Purchased power and fuel	222	197	25	555	484	71
Operating and maintenance	191	190	1	466	398	68
Depreciation and amortization	74	71	3	149	141	8
Taxes other than income	39	35	4	79	74	5
Total operating expenses	526	493	33	1,249	1,097	152
Operating income	127	137	(10)	269	329	(60)
Other income and (deductions)						
Interest expense, net	(32)	(31)	(1)	(64)	(62)	(2)
Other, net	—	2	(2)	2	3	(1)
Total other income and (deductions)	(32)	(29)	(3)	(62)	(59)	(3)
Income before income taxes	95	108	(13)	207	270	(63)
Income taxes	(1)	20	(21)	(3)	55	(58)
Net income	$ 96	$ 88	$ 8	$ 210	$ 215	$ (5)

BGE

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017 (a)	Variance	2018	2017 (a)	Variance
Operating revenues	$ 662	$ 674	$ (12)	$ 1,639	$ 1,625	$ 14
Operating expenses						
Purchased power and fuel	229	234	(5)	609	584	25
Operating and maintenance	176	174	2	397	357	40
Depreciation and amortization	114	112	2	248	239	9
Taxes other than income	59	56	3	124	119	5
Total operating expenses	578	576	2	1,378	1,299	79
Gain on sales of assets	1	—	1	1	—	1
Operating income	85	98	(13)	262	326	(64)
Other income and (deductions)						
Interest expense, net	(25)	(26)	1	(51)	(54)	3
Other, net	4	4	—	9	8	1
Total other income and (deductions)	(21)	(22)	1	(42)	(46)	4
Income before income taxes	64	76	(12)	220	280	(60)
Income taxes	13	31	(18)	41	111	(70)
Net income	51	45	6	$ 179	$ 169	$ 10

(a) Certain immaterial prior year amounts in the Registrants' Consolidated Statements of Operations and Comprehensive Income have been recasted to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018.

EXELON CORPORATION
Business Segment Comparative Statements of Operations
(unaudited)
(in millions)

	PHI (b)					
	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017 (a)	Variance	2018	2017 (a)	Variance
Operating revenues	$ 1,076	$ 1,074	$ 2	$ 2,327	$ 2,248	$ 79
Operating expenses						
Purchased power and fuel	381	383	(2)	901	845	56
Operating and maintenance	255	269	(14)	563	524	39
Depreciation and amortization	180	165	15	363	332	31
Taxes other than income	107	110	(3)	221	221	—
Total operating expenses	923	927	(4)	2,048	1,922	126
Gain on sales of assets	—	1	(1)	—	1	(1)
Operating income	153	148	5	279	327	(48)
Other income and (deductions)						
Interest expense, net	(65)	(59)	(6)	(128)	(122)	(6)
Other, net	11	13	(2)	22	26	(4)
Total other income and (deductions)	(54)	(46)	(8)	(106)	(96)	(10)
Income before income taxes	99	102	(3)	173	231	(58)
Income taxes	15	36	(21)	24	26	(2)
Net income	$ 84	$ 66	$ 18	$ 149	$ 205	$ (56)

	Other (c)					
	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017 (a)	Variance	2018	2017 (a)	Variance
Operating revenues	$ (292)	$ (286)	$ (6)	$ (715)	$ (635)	$ (80)
Operating expenses						
Purchased power and fuel	(274)	(263)	(11)	(678)	(596)	(82)
Operating and maintenance	(57)	(77)	20	(129)	(146)	17
Depreciation and amortization	23	22	1	46	43	3
Taxes other than income	10	7	3	22	17	5
Total operating expenses	(298)	(311)	13	(739)	(682)	(57)
Gain on sales of assets	1	—	1	—	—	—
Operating income	7	25	(18)	24	47	(23)
Other income and (deductions)						
Interest expense, net	(64)	(90)	26	(125)	(158)	33
Other, net	(4)	(27)	23	(13)	(51)	38
Total other income and (deductions)	(68)	(117)	49	(138)	(209)	71
Loss before income taxes	(61)	(92)	31	(114)	(162)	48
Income taxes	(27)	(105)	78	(57)	(215)	158
Equity in earnings of unconsolidated affiliates	—	—	—	1	1	—
Net (loss) income	$ (34)	$ 13	$ (47)	$ (56)	$ 54	$ (110)

(a) Certain immaterial prior year amounts in the Registrants' Consolidated Statements of Operations and Comprehensive Income have been recast to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018.
(b) PHI consolidated results includes Pepco, DPL and ACE.
(c) Other primarily includes eliminating and consolidating adjustments, Exelon’s corporate operations, shared service entities and other financing and investment activities.

EXELON CORPORATION
Consolidated Balance Sheets
(unaudited) (in millions)

	June 30, 2018	December 31, 2017 (a)
Assets		
Current assets		
Cash and cash equivalents	$ 694	$ 898
Restricted cash and cash equivalents	206	207
Accounts receivable, net		
Customer	4,094	4,445
Other	1,407	1,132
Mark-to-market derivative assets	799	976
Unamortized energy contract assets	46	60
Inventories, net		
Fossil fuel and emission allowances	270	340
Materials and supplies	1,320	1,311
Regulatory assets	1,293	1,267
Other	1,360	1,260
Total current assets	11,489	11,896
Property, plant and equipment, net	75,284	74,202
Deferred debits and other assets		
Regulatory assets	8,023	8,021
Nuclear decommissioning trust funds	13,110	13,272
Investments	636	640
Goodwill	6,677	6,677
Mark-to-market derivative assets	457	337
Unamortized energy contract assets	379	395
Other	1,194	1,330
Total deferred debits and other assets	30,476	30,672
Total assets	$ 117,249	$ 116,770

	June 30, 2018	December 31, 2017 (a)
Liabilities and shareholders' equity		
Current liabilities		
Short-term borrowings	$ 1,252	$ 929
Long-term debt due within one year	1,158	2,088
Accounts payable	3,113	3,532
Accrued expenses	1,665	1,837
Payables to affiliates	5	5
Regulatory liabilities	701	523
Mark-to-market derivative liabilities	268	232
Unamortized energy contract liabilities	171	231
Renewable energy credit obligation	257	352
PHI merger related obligation	63	87
Other	973	982
Total current liabilities	9,626	10,798
Long-term debt	33,179	32,176
Long-term debt to financing trusts	389	389
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	11,484	11,235
Asset retirement obligations	10,222	10,029
Pension obligations	3,412	3,736
Non-pension postretirement benefit obligations	2,132	2,093
Spent nuclear fuel obligation	1,157	1,147
Regulatory liabilities	9,677	9,865
Mark-to-market derivative liabilities	507	409
Unamortized energy contract liabilities	538	609
Other	2,087	2,097
Total deferred credits and other liabilities	41,216	41,220
Total liabilities	84,410	84,583
Commitments and contingencies		
Shareholders' equity		
Common stock	19,008	18,964
Treasury stock, at cost	(123)	(123)
Retained earnings	14,551	14,081
Accumulated other comprehensive loss, net	(2,921)	(3,026)
Total shareholders' equity	30,515	29,896
Noncontrolling interests	2,324	2,291
Total equity	32,839	32,187
Total liabilities and shareholders' equity	$ 117,249	$ 116,770

(a) Certain immaterial prior year amounts in the Registrants' Consolidated Balance Sheets have been recasted to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018.

EXELON CORPORATION
Consolidated Statements of Cash Flows
(unaudited)
(in millions)

	Six Months Ended June 30,	
	2018	**2017 (a)**
Cash flows from operating activities		
Net income	$ 1,179	$ 1,066
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion, including nuclear fuel and energy contract amortization	3,000	2,591
Impairment of long-lived assets and losses on regulatory assets	41	445
Gain on sales of assets and businesses	(60)	(5)
Bargain purchase gain	—	(226)
Deferred income taxes and amortization of investment tax credits	(2)	113
Net fair value changes related to derivatives	151	230
Net realized and unrealized losses (gains) on nuclear decommissioning trust fund investments	80	(284)
Other non-cash operating activities	479	415
Changes in assets and liabilities:		
Accounts receivable	(105)	301
Inventories	60	(23)
Accounts payable and accrued expenses	(342)	(810)
Option premiums paid, net	(36)	(8)
Collateral received (posted), net	81	(173)
Income taxes	129	58
Pension and non-pension postretirement benefit contributions	(345)	(325)
Other assets and liabilities	(441)	(470)
Net cash flows provided by operating activities	3,869	2,895
Cash flows from investing activities		
Capital expenditures	(3,807)	(3,845)
Proceeds from nuclear decommissioning trust fund sales	3,822	5,213
Investment in nuclear decommissioning trust funds	(3,924)	(5,339)
Acquisition of assets and businesses, net	(57)	(212)
Proceeds from sales of assets and businesses	89	211
Other investing activities	31	(9)
Net cash flows used in investing activities	(3,846)	(3,981)
Cash flows from financing activities		
Changes in short-term borrowings	200	422
Proceeds from short-term borrowings with maturities greater than 90 days	126	576
Repayments on short-term borrowings with maturities greater than 90 days	(1)	(510)
Issuance of long-term debt	1,488	981
Retirement of long-term debt	(1,309)	(1,049)
Dividends paid on common stock	(666)	(607)
Common stock issued from treasury stock	—	1,150
Proceeds from employee stock plans	27	43
Other financing activities	(50)	(23)
Net cash flows (used in) provided by financing activities	(185)	983
Decrease in cash, cash equivalents and restricted cash	(162)	(103)
Cash, cash equivalents and restricted cash at beginning of period	1,190	914
Cash, cash equivalents and restricted cash at end of period	$ 1,028	$ 811

(a) Certain immaterial prior year amounts in the Registrants' Consolidated Statements of Cash Flows have been recasted to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018.

EXELON CORPORATION
GAAP Consolidated Statements of Operations and
Adjusted (non-GAAP) Operating Earnings Reconciling Adjustments
(unaudited)
(in millions, except per share data)

	Three Months Ended June 30, 2018			Three Months Ended June 30, 2017 (a)		
	GAAP (b)	Non-GAAP Adjustments		GAAP (b)	Non-GAAP Adjustments	
Operating revenues	$ 8,076	$ 5	(c)	$ 7,665	$ 158	(c),(e)
Operating expenses						
Purchased power and fuel	3,315	76	(c),(i)	3,086	(48)	(c),(e)
Operating and maintenance	2,307	(68)	(f),(h),(i),(j),(k)	2,945	(524)	(f),(g),(h),(i),(j)
Depreciation and amortization	1,088	(152)	(i)	915	(35)	(i)
Taxes other than income	428	—		420	—	
Total operating expenses	7,138			7,366		
Gain on sales of assets and businesses	4	(1)	(i)	1	—	
Operating income	942			300		
Other income and (deductions)						
Interest expense, net	(373)	—		(436)	63	(h),(m)
Other, net	44	158	(d)	177	(66)	(d),(m)
Total other income and (deductions)	(329)			(259)		
Income before income taxes	613			41		
Income taxes	66	126	(c),(d),(h),(i),(j),(k),(l)	(62)	353	(c),(d),(e),(f),(g),(h),(i),(j),(m)
Equity in losses of unconsolidated affiliates	(5)	—		(9)	—	
Net income	542			94		
Net income (loss) attributable to noncontrolling interests	3	33	(n)	(1)	(20)	(n)
Net income attributable to common shareholders	$ 539			$ 95		
Effective tax rate[(o)]	10.8%			(151.2)%		
Earnings per average common share						
Basic	$ 0.56			$ 0.10		
Diluted	$ 0.56			$ 0.10		
Average common shares outstanding						
Basic	967			934		
Diluted	969			936		
Effect of adjustments on earnings per average diluted common share recorded in accordance with GAAP:						
Mark-to-market impact of economic hedging activities (c)		$ (0.07)			$ 0.12	
Unrealized gains (losses) related to NDT fund investments (d)		0.08			(0.05)	
Amortization of commodity contract intangibles (e)		—			0.01	
Merger and integration costs (f)		—			0.02	
Merger commitments (g)		—			—	
Long-lived asset impairments (h)		0.03			0.29	
Plant retirements and divestitures (i)		0.14			0.07	
Cost management program (j)		0.01			0.01	
Change in environmental liabilities (k)		0.01			—	
Reassessment of deferred income taxes (l)		(0.01)			—	
Like-kind exchange tax position (m)		—			(0.03)	
Noncontrolling interests (n)		(0.04)			0.02	
Total adjustments		$ 0.15			$ 0.46	

(a) Certain immaterial prior year amounts in the Registrants' Consolidated Statements of Operations and Comprehensive Income have been recasted to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018.
(b) Results reported in accordance with accounting principles generally accepted in the United States (GAAP).
(c) Adjustment to exclude the mark-to-market impact of Exelon’s economic hedging activities, net of intercompany eliminations.
(d) Adjustment to exclude the impact of net unrealized gains and losses on Generation’s NDT fund investments for Non-Regulatory and Regulatory Agreement Units. The impacts of the Regulatory Agreement Units, including the associated income taxes, are contractually eliminated, resulting in no earnings impact.

(e) Adjustment to exclude the non-cash amortization of intangible assets, net, primarily related to commodity contracts recorded at fair value related to the ConEdison Solutions and FitzPatrick acquisitions.
(f) Adjustment to exclude certain costs associated with mergers and acquisitions, including, if and when applicable, professional fees, employee-related expenses and integration activities. In 2017, reflects costs related to the PHI and FitzPatrick acquisitions, and in 2018, reflects costs related to the PHI acquisition.
(g) Adjustment to exclude costs incurred as part of the settlement orders approving the PHI acquisition.
(h) Adjustment to exclude charges to earnings related to the impairment of the ExGen Texas Power, LLC (EGTP) assets held for sale in 2017, and in 2018 the impairment of certain wind projects at Generation.
(i) Adjustment to exclude, in 2017, primarily reflects accelerated depreciation and amortization expenses and one-time charges associated with Generation's decision to early retire the Three Mile Island nuclear facility. In 2018, primarily reflects accelerated depreciation and amortization expense associated with Generation's decision to early retire the Oyster Creek and Three Mile Island nuclear facilities and a loss associated with Generation's sale of Residential Solar Holding, LLC, partially offset by a gain associated with Generation's sale of its electrical contracting business.
(j) Adjustment to exclude severance and reorganization costs related to a cost management program.
(k) Adjustment to exclude charges to adjust the environmental reserve associated with Cotter.
(l) Adjustment to exclude an adjustment to the remeasurement of deferred income taxes as a result of the Tax Cuts and Jobs Act (TCJA).
(m) Adjustment to exclude adjustments to income tax, penalties and interest expenses in the second quarter of 2017 as a result of the finalization of the IRS tax computation related to Exelon's like-kind exchange tax position.
(n) Adjustment to exclude elimination from Generation's results of the noncontrolling interest related to certain exclusion items, primarily related to the impact of unrealized gains and losses on NDT fund investments at CENG.
(o) The effective tax rate related to Adjusted (non-GAAP) Operating Earnings is 20.9% and 36.2% for the three months ended June 30, 2018 and June 30, 2017, respectively.

EXELON CORPORATION
GAAP Consolidated Statements of Operations and
Adjusted (non-GAAP) Operating Earnings Reconciling Adjustments
(unaudited)
(in millions, except per share data)

	Six Months Ended June 30, 2018			Six Months Ended June 30, 2017 (a)		
	GAAP (b)	**Non-GAAP Adjustments**		**GAAP (b)**	**Non-GAAP Adjustments**	
Operating revenues	$ 17,769	$ 102	(c)	$ 16,413	$ 116	(c),(e)
Operating expenses						
Purchased power and fuel	8,042	(107)	(c),(i)	6,985	(141)	(c),(e),(i)
Operating and maintenance	4,691	(104)	(f),(h),(i),(j),(l)	5,383	(572)	(f),(g),(h),(i),(j)
Depreciation and amortization	2,179	(289)	(i)	1,811	(37)	(e),(i)
Taxes other than income	874	—		857	—	
Total operating expenses	15,786			15,036		
Gain on sales of assets and businesses	60	(54)	(i)	5	(1)	(i)
Bargain purchase gain	—	—		226	(226)	(k)
Operating income	2,043			1,608		
Other income and (deductions)						
Interest expense, net	(745)	—		(809)	59	(h),(o),(m)
Other, net	17	269	(d)	434	(274)	(d),(m)
Total other income and (deductions)	(728)			(375)		
Income before income taxes	1,315			1,233		
Income taxes	125	274	(c),(d),(f),(h),(i),(j),(l),(n)	149	441	(c),(d),(e),(f),(g),(h),(i),(j),(m),(n),(o)
Equity in losses of unconsolidated affiliates	(11)	—		(18)	—	
Net income	1,179			1,066		
Net income (loss) attributable to noncontrolling interests	54	57	(p)	(20)	(55)	(p)
Net income attributable to common shareholders	$ 1,125			$ 1,086		
Effective tax rate[q]	9.5%			12.1%		
Earnings per average common share						
Basic	$ 1.16			$ 1.17		
Diluted	$ 1.16			$ 1.17		
Average common shares outstanding						
Basic	967			931		
Diluted	968			932		
Effect of adjustments on earnings per average diluted common share recorded in accordance with GAAP:						
Mark-to-market impact of economic hedging activities (c)		$ 0.13			$ 0.15	
Unrealized gains (losses) related to NDT fund investments (d)		0.15			(0.15)	
Amortization of commodity contract intangibles (e)		—			0.02	
Merger and integration costs (f)		—			0.04	
Merger commitments (g)		—			(0.15)	
Long-lived asset impairments (h)		0.03			0.29	
Plant retirements and divestitures (i)		0.23			0.07	
Cost management program (j)		0.02			0.01	
Bargain purchase gain (k)		—			(0.24)	
Change in environmental liabilities (l)		0.01			—	
Like-kind exchange tax position (m)		—			(0.03)	
Reassessment of deferred income taxes (n)		(0.01)			(0.02)	
Tax settlements (o)		—			(0.01)	
Noncontrolling interests (p)		(0.06)			0.06	
Total adjustments		$ 0.50			$ 0.04	

(a) Certain immaterial prior year amounts in the Registrants' Consolidated Statements of Operations and Comprehensive Income have been recasted to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018.
(b) Results reported in accordance with accounting principles generally accepted in the United States (GAAP).
(c) Adjustment to exclude the mark-to-market impact of Exelon’s economic hedging activities, net of intercompany eliminations.
(d) Adjustment to exclude the impact of net unrealized gains and losses on Generation’s NDT fund investments for Non-Regulatory and Regulatory Agreement Units. The impacts of the Regulatory Agreement Units, including the associated income taxes, are contractually eliminated, resulting in no earnings impact.
(e) Adjustment to exclude the non-cash amortization of intangible assets, net, primarily related to commodity contracts recorded at fair value related to the ConEdison Solutions and FitzPatrick acquisitions.
(f) Adjustment to exclude certain costs associated with mergers and acquisitions, including, if and when applicable, professional fees, employee-related expenses and integration activities. In 2017, reflects costs related to the PHI and FitzPatrick acquisitions, offset at PHI by the anticipated recovery of previously incurred PHI acquisition costs, and in 2018, reflects costs related to the PHI acquisition.
(g) Adjustment to exclude a decrease in reserves for uncertain tax positions related to the deductibility of certain merger commitments associated with the 2012 CEG and 2016 PHI acquisitions.
(h) Adjustment to exclude charges to earnings related to the impairment of the ExGen Texas Power, LLC (EGTP) assets held for sale in 2017, and in 2018 the impairment of certain wind projects at Generation.
(i) Adjustment to exclude accelerated depreciation and amortization expenses and one-time charges associated with Generation's decision to early retire the Three Mile Island nuclear facility in 2017. In 2018, primarily reflects accelerated depreciation and amortization expenses and one-time charges associated with Generation's decision to early retire the Oyster Creek nuclear facility, as well as accelerated depreciation and amortization expenses associated with the 2017 decision to early retire the Three Mile Island nuclear facility and a loss associated with Generation's sale of Residential Solar Holding, LLC, partially offset by a gain associated with Generation's sale of its electrical contracting business.
(j) Adjustment to exclude severance and reorganization costs related to a cost management program.
(k) Adjustment to exclude the excess of the fair value of assets and liabilities acquired over the purchase price for the FitzPatrick acquisition.
(l) Adjustment to exclude charges to adjust the environmental reserve associated with Cotter.
(m) Adjustment to exclude adjustments to income tax, penalties and interest expenses in the second quarter of 2017 as a result of the finalization of the IRS tax computation related to Exelon’s like-kind exchange tax position.
(n) Adjustment to exclude the change in the District of Columbia statutory tax rate in 2017, and in 2018, an adjustment to the remeasurement of deferred income taxes as a result of the Tax Cuts and Jobs Act (TCJA).
(o) Adjustment to exclude benefits related to the favorable settlement in 2017 of certain income tax positions related to PHI's unregulated business interests.
(p) Adjustment to exclude elimination from Generation’s results of the noncontrolling interest related to certain exclusion items, primarily related to the impact of unrealized gains and losses on NDT fund investments at CENG.
(q) The effective tax rate related to Adjusted (non-GAAP) Operating Earnings is 18.7% and 35.6% for the six months ended June 30, 2018 and June 30, 2017, respectively.

EXELON CORPORATION
Reconciliation of Adjusted (non-GAAP) Operating
Earnings to GAAP Net Income (in millions)
Three Months Ended June 30, 2018 and 2017
(unaudited)

	Exelon Earnings per Diluted Share	Generation	ComEd	PECO	BGE	PHI (a)	Other (b)	Exelon
2017 GAAP Net Income (Loss) (c)	**$ 0.10**	**$ (235)**	**$ 118**	**$ 88**	**$ 45**	**$ 66**	**$ 13**	**$ 95**
2017 Adjusted (non-GAAP) Operating (Earnings) Loss Adjustments:								
Mark-to-Market Impact of Economic Hedging Activities (net of taxes of $71, $1 and $72, respectively)	0.12	114	—	—	—	—	(1)	113
Unrealized Gains Related to NDT Fund Investments (net of taxes of $20) (1)	(0.05)	(45)	—	—	—	—	—	(45)
Amortization of Commodity Contract Intangibles (net of taxes of $8) (2)	0.01	12	—	—	—	—	—	12
Merger and Integration Costs (net of taxes of $7, $1, $1 and $9, respectively) (3)	0.02	12	—	—	—	1	2	15
Merger Commitments (net of taxes of $3, $3 and $0, respectively) (4)	—	—	—	—	—	(4)	4	—
Long-Lived Asset Impairments (net of taxes of $171, $1 and $172) (5)	0.29	269	—	—	—	—	(1)	268
Plant Retirements and Divestitures (net of taxes of $42) (6)	0.07	66	—	—	—	—	—	66
Cost Management Program (net of taxes of $3, $1, $1 and $4, respectively) (7)	0.01	4	—	1	1	—	—	6
Like-Kind Exchange Tax Position (net of taxes of $9, $75 and $66, respectively) (8)	(0.03)	—	23	—	—	—	(49)	(26)
Noncontrolling Interests (net of taxes of $5) (9)	0.02	20	—	—	—	—	—	20
2017 Adjusted (non-GAAP) Operating Earnings (Loss)	**0.56**	**217**	**141**	**89**	**46**	**63**	**(32)**	**524**
Year Over Year Effects on Earnings:								
ComEd, PECO, BGE and PHI Margins:								
Weather	0.01	—	— (d)	6	— (d)	1 (d)	—	7
Load	0.01	—	— (d)	6	— (d)	4 (d)	—	10
Other Energy Delivery (12)	(0.06)	—	(41) (e)	(14) (e)	(5) (e)	(2) (e)	—	(62)
Generation Energy Margins, Excluding Mark-to-Market:								
Nuclear Volume (13)	0.04	37	—	—	—	—	—	37
Nuclear Fuel Cost (14)	—	1	—	—	—	—	—	1
Capacity Pricing (15)	0.05	52	—	—	—	—	—	52
Zero Emission Credit Revenue (16)	0.03	33	—	—	—	—	—	33
Market and Portfolio Conditions (17)	(0.16)	(151)	—	—	—	—	—	(151)
Operating and Maintenance Expense:								
Labor, Contracting and Materials (18)	0.05	45	8	(5)	(2)	3	—	49
Planned Nuclear Refueling Outages (19)	0.03	31	—	—	—	—	—	31
Pension and Non-Pension Postretirement Benefits	0.01	5	1	1	1	2	—	10
Other Operating and Maintenance (20)	0.06	23	29	2	(1)	9	(3)	59
Depreciation and Amortization Expense (21)	(0.04)	(12)	(14)	(2)	(1)	(11)	—	(40)
Interest Expense, Net	0.01	10	1	—	1	(4)	1	9
Tax Cuts and Jobs Act Tax Savings (22)	0.13	40	44	12	14	22	(9)	123
Income Taxes (23)	0.01	3	(1)	6	—	(1)	1	8
Equity in Losses of Unconsolidated Affiliates	—	3	—	—	—	—	—	3
Noncontrolling Interests (24)	(0.05)	(58)	—	—	—	—	—	(58)
Other (25)	0.04	52	(4)	(4)	(1)	—	(2)	41
Share Differential (26)	(0.02)	—	—	—	—	—	—	—
2018 Adjusted (non-GAAP) Operating Earnings (Loss)	**0.71**	**331**	**164**	**97**	**52**	**86**	**(44)**	**686**
2018 Adjusted (non-GAAP) Operating Earnings (Loss) Adjustments:								
Mark-to-Market Impact of Economic Hedging Activities (net of taxes of $23)	0.07	67	—	—	—	—	—	67
Unrealized Losses Related to NDT Fund Investments (net of taxes of $77) (1)	(0.08)	(81)	—	—	—	—	—	(81)
Merger and Integration Costs (net of taxes of $0) (3)	—	(1)	—	—	—	—	—	(1)
Long-Lived Asset Impairments (net of taxes of $11) (5)	(0.03)	(30)	—	—	—	—	—	(30)
Plant Retirements and Divestitures (net of taxes of $47) (6)	(0.14)	(127)	—	—	—	—	—	(127)
Cost Management Program (net of taxes of $4, $0, $0, $0 and $4, respectively) (7)	(0.01)	(9)	—	(1)	(1)	(1)	—	(12)
Change in Environment Liabilities (net of taxes of $2) (10)	(0.01)	(5)	—	—	—	—	—	(5)
Reassessment of Deferred Income Taxes (entire amount represents tax expense) (11)	0.01	(1)	—	—	—	(1)	10	8
Noncontrolling Interests (net of taxes of $7) (9)	0.04	34	—	—	—	—	—	34
2018 GAAP Net Income (Loss)	**$ 0.56**	**$ 178**	**$ 164**	**$ 96**	**$ 51**	**$ 84**	**$ (34)**	**$ 539**

Note:
Unless otherwise noted, the income tax impact of each reconciling item between GAAP Net Income and Adjusted (non-GAAP) Operating Earnings is based on the marginal statutory federal and state income tax rates for each Registrant, taking into account whether the income or expense item is taxable or deductible, respectively, in whole or in part. For all items except the unrealized gains and losses related to NDT fund investments, the marginal statutory income tax rates for 2018 and 2017 ranged from 26.0 percent to 29.0 percent and 39.0 percent to 41.0 percent, respectively. Under IRS regulations, NDT fund investment returns are taxed at different rates for investments if they are in qualified or non-qualified funds. The effective tax rates for the unrealized gains and losses related to NDT fund investments were 48.9 percent and 31.4 percent for the three months ended June 30, 2018 and 2017, respectively.

(a) PHI consolidated results includes Pepco, DPL and ACE.
(b) Other primarily includes eliminating and consolidating adjustments, Exelon's corporate operations, shared service entities and other financing and investment activities.
(c) Certain immaterial prior year amounts in the Registrants' Consolidated Statements of Operations and Comprehensive Income have been recasted to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018.
(d) For ComEd, BGE, Pepco and DPL Maryland, customer rates are adjusted to eliminate the impacts of weather and customer usage on distribution volumes.
(e) For regulatory recovery mechanisms, including ComEd's distribution formula rate, ComEd, PECO, BGE and PHI utilities transmission formula rates, and riders across all utilities, revenues increase and decrease i) as fully recoverable costs fluctuate (with no impact on net earnings), and ii) pursuant to changes in rate base, capital structure and ROE (which impact net earnings).
(1) Reflects the impact of net unrealized gains and losses on Generation's NDT fund investments for Non-Regulatory and Regulatory Agreement Units. The impacts of the Regulatory Agreement Units, including the associated income taxes, are contractually eliminated, resulting in no earnings impact.
(2) Represents the non-cash amortization of intangible assets, net, primarily related to commodity contracts recorded at fair value related to the ConEdison Solutions and FitzPatrick acquisitions.
(3) Reflects certain costs associated with mergers and acquisitions, including, if and when applicable, professional fees, employee-related expenses and integration activities. In 2017, reflects costs related to the PHI and FitzPatrick acquisitions, and in 2018, reflects costs related to the PHI acquisition.
(4) Represents costs incurred as part of the settlement orders approving the PHI acquisition.
(5) Primarily reflects charges to earnings related to the impairment of the ExGen Texas Power, LLC (EGTP) assets held for sale in 2017, and in 2018 the impairment of certain wind projects at Generation.
(6) In 2017, primarily reflects accelerated depreciation and amortization expenses and one-time charges associated with Generation's decision to early retire the Three Mile Island nuclear facility. In 2018, primarily reflects accelerated depreciation and amortization expense associated with Generation's decision to early retire the Oyster Creek and Three Mile Island nuclear facilities and a loss associated with Generation's sale of Residential Solar Holding, LLC, partially offset by a gain associated with Generation's sale of its electrical contracting business.
(7) Represents severance and reorganization costs related to a cost management program.
(8) Represents adjustments to income tax, penalties and interest expenses in the second quarter of 2017 as a result of the finalization of the IRS tax computation related to Exelon's like-kind exchange tax position.
(9) Represents elimination from Generation's results of the noncontrolling interest related to certain exclusion items, primarily related to the impact of unrealized gains and losses on NDT fund investments at CENG.
(10) Represents charges to adjust the environmental reserve associated with Cotter.
(11) Reflects an adjustment to the remeasurement of deferred income taxes as a result of the Tax Cuts and Jobs Act (TCJA).
(12) For all utilities, primarily reflects lower revenues resulting from the anticipated pass back of TCJA tax savings through customer rates. Additionally, for ComEd, reflects decreased revenues resulting from the change to defer and recover over time energy efficiency costs pursuant to the Illinois Future Energy Jobs Act (FEJA), partially offset by increased electric distribution revenues due to higher rate base. For BGE and PHI, reflects increased revenue as a result of rate increases.
(13) Primarily reflects a decrease in nuclear outage days.
(14) Primarily reflects a decrease in fuel prices, partially offset by increased nuclear output.
(15) Primarily reflects increased capacity prices in the New England, Mid-Atlantic and Midwest regions.
(16) Primarily reflects the impact of the Illinois Zero Emission Standard.
(17) Primarily reflects lower realized energy prices, lower energy efficiency revenues, partially offset by the impacts of Generation's natural gas portfolio.
(18) For Generation, primarily reflects decreased spending related to energy efficiency projects and decreased costs related to the sale of Generation's electrical contracting business.
(19) Primarily reflects a decrease in the number of nuclear outage days in 2018, excluding Salem.
(20) For Generation, primarily reflects fewer outages at Salem. For ComEd, primarily reflects the change to defer and recover over time energy efficiency costs pursuant to FEJA. For PHI, reflects a decrease in uncollectible accounts expense.
(21) Reflects ongoing capital expenditures across all operating companies. In addition, for ComEd, reflects the amortization of deferred energy efficiency costs pursuant to FEJA. For BGE, reflects an offset due to certain regulatory assets that became fully amortized as of December 31, 2017. For PHI, reflects increased amortization of Pepco's DC PLUG regulatory asset, which is offset in Other Energy and Delivery.
(22) Reflects the benefit of lower federal income tax rates and the settlement of a portion of the deferred income tax regulatory liabilities established upon enactment of the TCJA, which is predominantly offset at the utilities in Other Energy Delivery as these tax benefits are anticipated to be passed back through customer rates.
(23) For Generation, primarily reflects a one-time tax adjustment.
(24) Reflects elimination from Generation's results of activity attributable to noncontrolling interests, primarily for CENG and the Renewables Joint Venture.
(25) For Generation, primarily reflects higher realized NDT fund gains.
(26) Reflects the impact on earnings per share due to the increase in Exelon's average diluted common shares outstanding as a result of the June 2017 common stock issuance.

EXELON CORPORATION
Reconciliation of Adjusted (non-GAAP) Operating Earnings to GAAP Net Income (in millions)
Six Months Ended June 30, 2018 and 2017
(unaudited)

	Exelon Earnings per Diluted Share	Generation	ComEd	PECO	BGE	PHI (a)	Other (b)	Exelon
2017 GAAP Net Income (c)	**$ 1.17**	**$ 184**	**$ 259**	**$ 215**	**$ 169**	**$ 205**	**$ 54**	**$ 1,086**
2017 Adjusted (non-GAAP) Operating (Earnings) Loss Adjustments:								
Mark-to-Market Impact of Economic Hedging Activities (net of taxes of $90, $1 and $91, respectively)	0.15	143	—	—	—	—	(1)	142
Unrealized Gains Related to NDT Fund Investments (net of taxes of $130) (1)	(0.15)	(144)	—	—	—	—	—	(144)
Amortization of Commodity Contract Intangibles (net of taxes of $9) (2)	0.02	15	—	—	—	—	—	15
Merger and Integration Costs (net of taxes of $23, $1, $1, $1, $1 and $25, respectively) (3)	0.04	37	—	1	1	(1)	2	40
Merger Commitments (net of taxes of $18, $52, $67 and $137, respectively) (4)	(0.15)	(18)	—	—	—	(60)	(59)	(137)
Long-Lived Asset Impairments (net of taxes of $171, $1 and $172, respectively) (5)	0.29	269	—	—	—	—	(1)	268
Plant Retirements and Divestitures (net of taxes of $42) (6)	0.07	66	—	—	—	—	—	66
Cost Management Program (net of taxes of $4, $1, $1, $0 and $7, respectively) (7)	0.01	7	—	2	2	—	(1)	10
Bargain Purchase Gain (net of taxes of $0) (8)	(0.24)	(226)	—	—	—	—	—	(226)
Like-Kind Exchange Tax Position (net of taxes of $9, $75 and $66, respectively) (9)	(0.03)	—	23	—	—	—	(49)	(26)
Reassessment of Deferred Income Taxes (entire amount represents tax expense) (10)	(0.02)	—	—	—	—	—	(20)	(20)
Tax Settlements (net of taxes of $1) (11)	(0.01)	(5)	—	—	—	—	—	(5)
Noncontrolling Interests (net of taxes of $12) (12)	0.06	55	—	—	—	—	—	55
2017 Adjusted (non-GAAP) Operating Earnings (Loss)	**1.21**	**383**	**282**	**218**	**172**	**144**	**(75)**	**1,124**
Year Over Year Effects on Earnings:								
ComEd, PECO, BGE and PHI Margins:								
Weather	0.04	—	— (d)	26	— (d)	11 (d)	—	37
Load	0.02	—	— (d)	8	— (d)	12 (d)	—	20
Other Energy Delivery (14)	(0.12)	—	(82) (e)	(19) (e)	(8) (e)	(6) (e)	—	(115)
Generation Energy Margins, Excluding Mark-to-Market:								
Nuclear Volume (15)	0.10	98	—	—	—	—	—	98
Nuclear Fuel Cost (16)	—	(4)	—	—	—	—	—	(4)
Capacity Pricing (17)	0.11	111	—	—	—	—	—	111
Zero Emission Credit Revenue (18)	0.27	266	—	—	—	—	—	266
Market and Portfolio Conditions (19)	(0.23)	(223)	—	—	—	—	—	(223)
Operating and Maintenance Expense:								
Labor, Contracting and Materials (20)	0.07	85	1	(8)	(5)	(7)	—	66
Planned Nuclear Refueling Outages (21)	0.06	55	—	—	—	—	—	55
Pension and Non-Pension Postretirement Benefits	0.01	7	—	2	1	4	(1)	13
Other Operating and Maintenance (22)	0.06	65	77	(45)	(26)	(16)	7	62
Depreciation and Amortization Expense (23)	(0.09)	(19)	(29)	(6)	(7)	(22)	(1)	(84)
Interest Expense, Net	0.02	13	(2)	—	2	(5)	7	15
Tax Cuts and Jobs Act Tax Savings (24)	0.27	69	90	32	53	43	(21)	266
Income Taxes (25)	0.04	19	(5)	8	1	(3)	20	40
Equity in Losses of Unconsolidated Affiliates	0.01	5	—	—	—	—	—	5
Noncontrolling Interests (26)	(0.20)	(193)	—	—	—	—	—	(193)
Other (27)	0.05	68	(3)	(5)	(2)	(4)	(2)	52
Share Differential (28)	(0.04)	—	—	—	—	—	—	—
2018 Adjusted (non-GAAP) Operating Earnings (Loss)	**1.66**	**805**	**$ 329**	**211**	**181**	**151**	**(66)**	**1,611**
2018 Adjusted (non-GAAP) Operating Earnings (Loss) Adjustments:								
Mark-to-Market Impact of Economic Hedging Activities (net of taxes of $45, $1 and $46, respectively)	(0.13)	(130)	—	—	—	—	1	(129)
Unrealized Losses Related to NDT Fund Investments (net of taxes of $122) (1)	(0.15)	(147)	—	—	—	—	—	(147)
Merger and Integration Costs (net of taxes of $2) (3)	—	(4)	—	—	—	—	—	(4)
Long-Lived Asset Impairments (net of taxes of $11) (5)	(0.03)	(30)	—	—	—	—	—	(30)
Plant Retirements and Divestitures (net of taxes of $79, $1 and $78, respectively) (6)	(0.23)	(219)	—	—	—	—	(1)	(220)
Cost Management Program (net of taxes of $4, $1, $1, $0 and $6, respectively) (7)	(0.02)	(12)	—	(1)	(2)	(1)	—	(16)
Change in Environmental Liabilities (net of taxes of $2) (13)	(0.01)	(5)	—	—	—	—	—	(5)
Reassessment of Deferred Income Taxes (entire amount represents tax expense) (10)	0.01	(1)	—	—	—	(1)	10	8
Noncontrolling Interests (net of taxes of $13) (12)	0.06	57	—	—	—	—	—	57
2018 GAAP Net Income (Loss)	**$ 1.16**	**$ 314**	**$ 329**	**$ 210**	**$ 179**	**$ 149**	**$ (56)**	**$ 1,125**

Note:
Unless otherwise noted, the income tax impact of each reconciling item between GAAP Net Income and Adjusted (non-GAAP) Operating Earnings is based on the marginal statutory federal and state income tax rates for each Registrant, taking into account whether the income or expense item is taxable or deductible, respectively, in whole or in part. For all items except the unrealized gains and losses related to NDT fund investments, the marginal statutory income tax rates for 2018 and 2017 ranged from 26.0 percent to 29.0 percent and 39.0 percent to 41.0 percent, respectively. Under IRS regulations, NDT fund investment returns are taxed at different rates for investments if they are in qualified or non-qualified funds. The effective tax rates for the unrealized gains and losses related to NDT fund investments were 45.3 percent and 47.5 percent for the six months ended June 30, 2018 and 2017, respectively.

(a) PHI consolidated results includes Pepco, DPL and ACE.
(b) Other primarily includes eliminating and consolidating adjustments, Exelon's corporate operations, shared service entities and other financing and investment activities.
(c) Certain immaterial prior year amounts in the Registrants' Consolidated Statements of Operations and Comprehensive Income have been recasted to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018.
(d) For ComEd, BGE, Pepco and DPL Maryland, customer rates are adjusted to eliminate the impacts of weather and customer usage on distribution volumes.
(e) For regulatory recovery mechanisms, including ComEd's distribution formula rate, ComEd, PECO, BGE and PHI utilities transmission formula rates, and riders across all utilities, revenues increase and decrease i) as fully recoverable costs fluctuate (with no impact on net earnings), and ii) pursuant to changes in rate base, capital structure and ROE (which impact net earnings).
(1) Reflects the impact of net unrealized gains and losses on Generation's NDT fund investments for Non-Regulatory and Regulatory Agreement Units. The impacts of the Regulatory Agreement Units, including the associated income taxes, are contractually eliminated, resulting in no earnings impact.
(2) Represents the non-cash amortization of intangible assets, net, primarily related to commodity contracts recorded at fair value related to the ConEdison Solutions and FitzPatrick acquisitions.
(3) Reflects certain costs associated with mergers and acquisitions, including, if and when applicable, professional fees, employee-related expenses and integration activities. In 2017, reflects costs related to the PHI and FitzPatrick acquisitions, offset at PHI by the anticipated recovery of previously incurred PHI acquisition costs, and in 2018, reflects costs related to the PHI acquisition.
(4) Primarily reflects a decrease in reserves for uncertain tax positions related to the deductibility of certain merger commitments associated with the 2012 CEG and 2016 PHI acquisitions.
(5) Primarily reflects charges to earnings related to the impairment of the ExGen Texas Power, LLC (EGTP) assets held for sale in 2017, and in 2018 the impairment of certain wind projects at Generation.
(6) Primarily reflects accelerated depreciation and amortization expenses and one-time charges associated with Generation's previous decision to early retire the Three Mile Island nuclear facility in 2017. In 2018, primarily reflects accelerated depreciation and amortization expenses and one-time charges associated with Generation's decision to early retire the Oyster Creek nuclear facility, as well as accelerated depreciation and amortization expenses associated with the 2017 decision to early retire the Three Mile Island nuclear facility and a loss associated with Generation's sale of Residential Solar Holding, LLC, partially offset by a gain associated with Generation's sale of its electrical contracting business.
(7) Represents severance and reorganization costs related to a cost management program.
(8) Represents the excess of the fair value of assets and liabilities acquired over the purchase price for the FitzPatrick acquisition.
(9) Represents adjustments to income tax, penalties and interest expenses in the second quarter of 2017 as a result of the finalization of the IRS tax computation related to Exelon's like-kind exchange tax position.
(10) Reflects the change in the District of Columbia statutory tax rate in 2017, and in 2018, an adjustment to the remeasurement of deferred income taxes as a result of the Tax Cuts and Jobs Act (TCJA).
(11) Reflects benefits related to the favorable settlement in 2017 of certain income tax positions related to PHI's unregulated business interests.
(12) Represents elimination from Generation's results of the noncontrolling interest related to certain exclusion items, primarily related to the impact of unrealized gains and losses on NDT fund investments at CENG.
(13) Represents charges to adjust the environmental reserve associated with Cotter.
(14) For all utilities, primarily reflects lower revenues resulting from the anticipated pass back of TCJA savings through customer rates, partially offset by higher mutual assistance revenues. Additionally, for ComEd, reflects decreased revenues resulting from the change to defer and recover over time energy efficiency costs pursuant to the Illinois Future Energy Jobs Act (FEJA), partially offset by increased electric distribution revenues due to higher rate base. For BGE and PHI, reflects increased revenue as a result of rate increases.
(15) Primarily reflects the acquisition of the FitzPatrick nuclear facility and decreased nuclear outage days.
(16) Primarily reflects increased nuclear output as a result of the FitzPatrick acquisition, partially offset by a decrease in fuel prices.
(17) Primarily reflects increased capacity prices in the New England, Mid-Atlantic and Midwest regions.
(18) Reflects the impact of the New York Clean Energy and Illinois Zero Emission Standards, including the impact of zero emission credits generated in Illinois from June 1, 2017 through December 31, 2017.
(19) Primarily reflects lower realized energy prices, lower energy efficiency revenues, the impact of the deconsolidation of EGTP in 2017 and the conclusion of the Ginna Reliability Support Services Agreement, partially offset by the impacts of Generation's natural gas portfolio and the addition of two combined-cycle gas turbines in Texas.
(20) For Generation, primarily reflects decreased spending related to energy efficiency projects and decreased costs related to the sale of Generation's electrical contracting business. Additionally, for the utilities, primarily reflects increased mutual assistance expenses.
(21) Primarily reflects a decrease in the number of nuclear outage days in 2018, excluding Salem.
(22) For Generation, primarily reflects the impact of a supplemental NEIL insurance distribution and fewer outage days at Salem, partially offset by increased expenses related to the acquisition of FitzPatrick. For ComEd, primarily reflects the change to defer and recover over time energy efficiency costs pursuant to the FEJA. For PECO and BGE, primarily reflects increased storm costs related to the March 2018 winter storms. For PHI, primarily reflects an increase in uncollectible accounts expense. Additionally, for the utilities, reflects increased mutual assistance expenses.
(23) Reflects ongoing capital expenditures across all operating companies. In addition, for ComEd, reflects the amortization of deferred energy efficiency costs pursuant to FEJA. For BGE, reflects an offset due to certain regulatory assets that became fully amortized as of December 31, 2017. For PHI, reflects increased amortization of Pepco's DC PLUG regulatory asset, which is offset in Other Energy and Delivery.
(24) Reflects the benefit of lower federal income tax rates and the settlement of a portion of the deferred income tax regulatory liabilities established upon enactment of TCJA, which is predominantly offset at the utilities in Other Energy Delivery as these tax benefits are anticipated to be passed back through customer rates.
(25) For Generation, primarily reflects one-time tax adjustment and renewable tax credit benefits.
(26) Reflects elimination from Generation's results of activity attributable to noncontrolling interests, primarily for CENG and the Renewables Joint Venture.
(27) For Generation, primarily reflects higher realized NDT fund gains.
(28) Reflects the impact on earnings per share due to the increase in Exelon's average diluted common shares outstanding as a result of the June 2017 common stock issuance.

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Generation

	Three Months Ended June 30, 2018			Three Months Ended June 30, 2017 (b)		
	GAAP (a)	Non-GAAP Adjustments		GAAP (a)	Non-GAAP Adjustments	
Operating revenues	$ 4,579	$ 5	(c)	$ 4,216	$ 158	(c),(e)
Operating expenses						
Purchased power and fuel	2,280	76	(c),(i)	2,157	(48)	(c),(e),(i)
Operating and maintenance	1,418	(64)	(f),(h),(i),(j),(n)	2,012	(516)	(f),(h),(i),(j)
Depreciation and amortization	466	(152)	(i)	334	(35)	(i)
Taxes other than income	134	—		140	—	
Total operating expenses	4,298			4,643		
Gain on sales of assets and businesses	1	(1)	(i)	—	—	
Operating income (loss)	282			(427)		
Other income and (deductions)						
Interest expense, net	(102)	—		(129)	21	(h)
Other, net	29	158	(d)	181	(64)	(d)
Total other income and (deductions)	(73)			52		
Income (loss) before income taxes	209			(375)		
Income taxes	23	116	(c),(d),(h),(i),(j),(l),(n)	(148)	282	(c),(d),(e),(f),(h),(i),(j)
Equity in losses of unconsolidated affiliates	(5)	—		(9)	—	
Net income (loss)	181			(236)		
Net income (loss) attributable to noncontrolling interests	3	33	(o)	(1)	(20)	(o)
Net income (loss) attributable to membership interest	$ 178			$ (235)		

	Six Months Ended June 30, 2018			Six Months Ended June 30, 2017 (b)		
	GAAP (a)	Non-GAAP Adjustments		GAAP (a)	Non-GAAP Adjustments	
Operating revenues	$ 10,090	$ 102	(c)	$ 9,093	$ 116	(c),(e)
Operating expenses						
Purchased power and fuel	5,573	(107)	(c),(i)	4,955	(141)	(c),(e),(i)
Operating and maintenance	2,756	(98)	(f),(h),(i),(j),(n)	3,503	(562)	(f),(h),(i),(j)
Depreciation and amortization	914	(289)	(i)	637	(37)	(e),(i)
Taxes other than income	272	—		282	—	
Total operating expenses	9,515			9,377		
Gain on sales of assets and businesses	54	(54)	(i)	4	(1)	(i)
Bargain purchase gain	—	—		226	(226)	(k),(i)
Operating income (loss)	629			(54)		
Other income and (deductions)						
Interest expense, net	(202)	—		(228)	18	(h),(m)
Other, net	(15)	269	(d)	440	(273)	(d)
Total other income and (deductions)	(217)			212		
Income before income taxes	412			158		
Income taxes	32	263	(c),(d),(f),(h),(i),(j),(l),(n)	(25)	230	(c),(d),(e),(f),(g),(h),(i),(j),(m)
Equity in losses of unconsolidated affiliates	(12)	—		(19)	—	
Net income	368			164		
Net income (loss) attributable to noncontrolling interests	54	57	(o)	(20)	(55)	(o)
Net income attributable to membership interest	$ 314			$ 184		

(a) Results reported in accordance with GAAP.
(b) Certain immaterial prior year amounts in the Registrants' Consolidated Statements of Operations and Comprehensive Income have been recasted to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018.
(c) Adjustment to exclude the mark-to-market impact of Exelon’s economic hedging activities, net of intercompany eliminations.
(d) Adjustment to exclude the impact of net unrealized gains and losses on Generation’s NDT fund investments for Non-Regulatory and Regulatory Agreement Units. The impacts of the Regulatory Agreement Units, including the associated income taxes, are contractually eliminated, resulting in no earnings impact.
(e) Adjustment to exclude the non-cash amortization of intangible assets, net, primarily related to commodity contracts recorded at fair value related to the ConEdison Solutions and FitzPatrick acquisitions.
(f) Adjustment to exclude certain costs associated with mergers and acquisitions, including, if and when applicable, professional fees, employee-related expenses and integration activities. In 2017, reflects costs related to the PHI and FitzPatrick acquisitions.
(g) Adjustment to exclude a decrease in reserves for uncertain tax positions related to the deductibility of certain merger commitments associated with the 2012 CEG and 2016 PHI acquisitions.
(h) Adjustment to exclude charges to earnings related to the impairment of the ExGen Texas Power, LLC (EGTP) assets held for sale in 2017, and in 2018 the impairment of certain wind projects.
(i) Adjustment to exclude accelerated depreciation and amortization expenses and one-time charges associated with Generation's decision to early retire the Three Mile Island nuclear facility in 2017. In 2018, primarily reflects accelerated depreciation and amortization expenses and one-time charges associated with Generation's decision to early retire the Oyster Creek nuclear facility, as well as accelerated depreciation and amortization expenses associated with the 2017 decision to early retire the Three Mile Island nuclear facility and a loss associated with Generation's sale of Residential Solar Holding, LLC, partially offset by a gain associated with Generation's sale of its electrical contracting business.
(j) Adjustment to exclude severance and reorganization costs related to a cost management program.
(k) Adjustment to exclude the excess of the fair value of assets and liabilities acquired over the purchase price for the FitzPatrick acquisition.
(l) Adjustment to exclude the change in the District of Columbia statutory tax rate in 2017, and in 2018, an adjustment to the remeasurement of deferred income taxes as a result of the Tax Cuts and Jobs Act (TCJA).
(m) Adjustment to exclude benefits related to the favorable settlement in 2017 of certain income tax positions related to PHI's unregulated business interests.
(n) Adjustment to exclude charges to adjust the environmental reserve associated with Cotter.
(o) Adjustment to exclude the elimination from Generation’s results of the noncontrolling interest related to certain exclusion items, primarily related to the impact of unrealized gains and losses on NDT fund investments at CENG.

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ComEd

	Three Months Ended June 30, 2018			Three Months Ended June 30, 2017 (b)		
	GAAP (a)	Non-GAAP Adjustments		GAAP (a)	Non-GAAP Adjustments	
Operating revenues	$ 1,398	$ —		$ 1,357	$ —	
Operating expenses						
Purchased power and fuel	477	—		378	—	
Operating and maintenance	324	—		377	(1)	(c)
Depreciation and amortization	231	—		211	—	
Taxes other than income	79	—		72	—	
Total operating expenses	1,111			1,038		
Gain on sales of assets	1	—		—	—	
Operating income	288			319		
Other income and (deductions)						
Interest expense, net	(85)	—		(101)	14	(c)
Other, net	4	—		4	—	
Total other income and (deductions)	(81)			(97)		
Income before income taxes	207			222		
Income taxes	43	—		104	(8)	(c)
Net income	$ 164			$ 118	$ 8	

	Six Months Ended June 30, 2018			Six Months Ended June 30, 2017 (b)		
	GAAP (a)	Non-GAAP Adjustments		GAAP (a)	Non-GAAP Adjustments	
Operating revenues	$ 2,910	$ —		$ 2,656	$ —	
Operating expenses						
Purchased power and fuel	1,082	—		713	—	
Operating and maintenance	638	—		747	(1)	(c)
Depreciation and amortization	459	—		419	—	
Taxes other than income	156	—		144	—	
Total operating expenses	2,335			2,023		
Gain on sales of assets	5	—		—	—	
Operating income	580			633		
Other income and (deductions)						
Interest expense, net	(175)	—		(185)	14	(c)
Other, net	12	—		8	—	
Total other income and (deductions)	(163)			(177)		
Income before income taxes	417			456		
Income taxes	88	—		197	(8)	(c)
Net income	$ 329			$ 259		

(a) Results reported in accordance with GAAP.
(b) Certain immaterial prior year amounts in the Registrants' Consolidated Statements of Operations and Comprehensive Income have been recasted to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018.
(c) Adjustment to exclude adjustments to income tax, penalties and interest expenses in the second quarter of 2017 as a result of the finalization of the IRS tax computation related to Exelon’s like-kind exchange tax position.

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PECO

	Three Months Ended June 30, 2018			Three Months Ended June 30, 2017		
	GAAP (a)	Non-GAAP Adjustments		GAAP (a)	Non-GAAP Adjustments	
Operating revenues	$ 653	$ —		$ 630	$ —	
Operating expenses						
Purchased power and fuel	222	—		197	—	
Operating and maintenance	191	(1)	(b)	190	(2)	(b)
Depreciation and amortization	74	—		71	—	
Taxes other than income	39	—		35	—	
Total operating expenses	526			493		
Operating income	127			137		
Other income and (deductions)						
Interest expense, net	(32)	—		(31)	—	
Other, net	—	—		2	—	
Total other income and (deductions)	(32)			(29)		
Income before income taxes	95			108		
Income taxes	(1)	—		20	1	(b)
Net income	$ 96			$ 88		

	Six Months Ended June 30, 2018			Six Months Ended June 30, 2017		
	GAAP (a)	Non-GAAP Adjustments		GAAP (a)	Non-GAAP Adjustments	
Operating revenues	$ 1,518	$ —		$ 1,426	$ —	
Operating expenses						
Purchased power and fuel	555	—		484	—	
Operating and maintenance	466	(2)	(b)	398	(5)	(b),(c)
Depreciation and amortization	149	—		141	—	
Taxes other than income	79	—		74	—	
Total operating expenses	1,249			1,097		
Operating income	269			329		
Other income and (deductions)						
Interest expense, net	(64)	—		(62)	—	
Other, net	2	—		3	—	
Total other income and (deductions)	(62)			(59)		
Income before income taxes	207			270		
Income taxes	(3)	1	(b)	55	2	(b),(c)
Net income	$ 210			$ 215		

(a) Results reported in accordance with GAAP.
(b) Adjustment to exclude reorganization costs related to a cost management program.
(c) Adjustment to exclude certain costs associated with mergers and acquisitions, including, if and when applicable, professional fees, employee-related expenses and integration activities related to the PHI acquisition.

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BGE

	Three Months Ended June 30, 2018			Three Months Ended June 30, 2017 (b)		
	GAAP (a)	Non-GAAP Adjustments		GAAP (a)	Non-GAAP Adjustments	
Operating revenues	$ 662	$ —		$ 674	$ —	
Operating expenses						
Purchased power and fuel	229	—		234	—	
Operating and maintenance	176	(2)	(c),(d)	174	(2)	(c),(d)
Depreciation and amortization	114	—		112	—	
Taxes other than income	59	—		56	—	
Total operating expenses	578			576		
Gain on sales of assets	1	—		—	—	
Operating income	85			98		
Other income and (deductions)						
Interest expense, net	(25)	—		(26)	—	
Other, net	4	—		4	—	
Total other income and (deductions)	(21)			(22)		
Income before income taxes	64			76		
Income taxes	13	1	(c),(d)	31	1	(c),(d)
Net income	$ 51			$ 45		

	Six Months Ended June 30, 2018			Six Months Ended June 30, 2017 (b)		
	GAAP (a)	Non-GAAP Adjustments		GAAP (a)	Non-GAAP Adjustments	
Operating revenues	$ 1,639	$ —		$ 1,625	$ —	
Operating expenses						
Purchased power and fuel	609	—		584	—	
Operating and maintenance	397	(3)	(c),(d)	357	(5)	(c),(d)
Depreciation and amortization	248	—		239	—	
Taxes other than income	124	—		119	—	
Total operating expenses	1,378			1,299		
Gain on sales of assets	1	—		—	—	
Operating income	262			326		
Other income and (deductions)						
Interest expense, net	(51)	—		(54)	—	
Other, net	9	—		8	—	
Total other income and (deductions)	(42)			(46)		
Income before income taxes	220			280		
Income taxes	41	1	(c),(d)	111	2	(c),(d)
Net income	$ 179			$ 169		

(a) Results reported in accordance with GAAP.
(b) Certain immaterial prior year amounts in the Registrants' Consolidated Statements of Operations and Comprehensive Income have been recasted to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018.
(c) Adjustment to exclude reorganization costs related to a cost management program.
(d) Adjustment to exclude certain costs associated with mergers and acquisitions, including, if and when applicable, professional fees, employee-related expenses, integration activities, and upfront credit facilities fees related to the PHI acquisition.

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PHI (c)

	Three Months Ended June 30, 2018			Three Months Ended June 30, 2017 (b)		
	GAAP (a)	Non-GAAP Adjustments		GAAP (a)	Non-GAAP Adjustments	
Operating revenues	$ 1,076	$ —		$ 1,074	$ —	
Operating expenses						
Purchased power and fuel	381	—		383	—	
Operating and maintenance	255	(1)	(d)	269	4	(f),(g)
Depreciation and amortization	180	—		165	—	
Taxes other than income	107	—		110	—	
Total operating expenses	923			927		
Gain on sales of assets	—	—		1	—	
Operating income	153			148		
Other income and (deductions)						
Interest expense, net	(65)	—		(59)	—	
Other, net	11	—		13	—	
Total other income and (deductions)	(54)			(46)		
Income before income taxes	99			102		
Income taxes	15	(1)	(d),(e)	36	(1)	(f),(g)
Net income	$ 84			$ 66		

	Six Months Ended June 30, 2018 (b)			Six Months Ended June 30, 2017 (b)		
	GAAP (a)	Non-GAAP Adjustments		GAAP (a)	Non-GAAP Adjustments	
Operating revenues	$ 2,327	$ —		$ 2,248	$ —	
Operating expenses						
Purchased power and fuel	901	—		845	—	
Operating and maintenance	563	(1)	(d)	524	10	(f),(g)
Depreciation and amortization	363	—		332	—	
Taxes other than income	221	—		221	—	
Total operating expenses	2,048			1,922		
Gain on sales of assets	—	—		1	—	
Operating income	279			327		
Other income and (deductions)						
Interest expense, net	(128)	—		(122)	—	
Other, net	22	—		26	—	
Total other income and (deductions)	(106)			(96)		
Income before income taxes	173			231		
Income taxes	24	(1)	(d),(e)	26	51	(f),(g)
Net income	$ 149			$ 205		

(a) Results reported in accordance with GAAP.
(b) Certain immaterial prior year amounts in the Registrants' Consolidated Statements of Operations and Comprehensive Income have been recast to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018.
(c) PHI consolidated results includes Pepco, DPL and ACE.
(d) Adjustment to exclude severance and reorganization costs related to a cost management program.
(e) Adjustment to exclude the change in the District of Columbia statutory tax rate in 2017, and in 2018, an adjustment to the remeasurement of deferred income taxes as a result of the Tax Cuts and Jobs Act (TCJA).

(f) Adjustment to exclude certain costs associated with mergers and acquisitions, including, if and when applicable, professional fees, employee-related expenses and integration activities. In 2017, reflects costs related to the PHI acquisition, partially offset at PHI by the anticipated recovery of previously incurred PHI acquisition costs.

(g) Adjustment to exclude a decrease in reserves for uncertain tax positions related to the deductibility of certain merger commitments associated with the 2016 PHI acquisition.

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	Other (a)					
	Three Months Ended June 30, 2018			Three Months Ended June 30, 2017 (b)		
	GAAP (c)	Non-GAAP Adjustments		GAAP (c)	Non-GAAP Adjustments	
Operating revenues	$ (292)	$ —		$ (286)	$ —	
Operating expenses						
Purchased power and fuel	(274)	—		(263)	—	
Operating and maintenance	(57)	—		(77)	(7)	(d),(i)
Depreciation and amortization	23	—		22	—	
Taxes other than income	10	—		7	—	
Total operating expenses	(298)			(311)		
Gain on sales of assets and businesses	1	—		—	—	
Operating income	7			25		
Other income and (deductions)						
Interest expense, net	(64)	—		(90)	28	(h)
Other, net	(4)	—		(27)	(2)	(h)
Total other income and (deductions)	(68)			(117)		
Loss before income taxes	(61)			(92)		
Income taxes	(27)	10	(f),(g)	(105)	78	(d),(e),(h),(i)
Net (loss) income	(34)			13		

	Six Months Ended June 30, 2018			Six Months Ended June 30, 2017 (b)		
	GAAP (c)	Non-GAAP Adjustments		GAAP (c)	Non-GAAP Adjustments	
Operating revenues	$ (715)	$ —		$ (635)	$ —	
Operating expenses						
Purchased power and fuel	(678)	—		(596)	—	
Operating and maintenance	(129)	—		(146)	(9)	(d),(i)
Depreciation and amortization	46	—		43	—	
Taxes other than income	22	—		17	—	
Total operating expenses	(739)			(682)		
Operating income	24			47		
Other income and (deductions)						
Interest expense, net	(125)	—		(158)	27	(h)
Other, net	(13)	—		(51)	(1)	(h)
Total other income and (deductions)	(138)			(209)		
Loss before income taxes	(114)			(162)		
Income taxes	(57)	10	(f),(g)	(215)	164	(d),(e),(g),(h),(i)
Equity in earnings of unconsolidated affiliates	1	—		1	—	
Net (loss) income	(56)			54		

(a) Other primarily includes eliminating and consolidating adjustments, Exelon’s corporate operations, shared service entities and other financing and investment activities.
(b) Certain immaterial prior year amounts in the Registrants' Consolidated Statements of Operations and Comprehensive Income have been recasted to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018.
(c) Results reported in accordance with GAAP.
(d) Adjustment to exclude certain costs associated with mergers and acquisitions, including, if and when applicable, professional fees, employee-related expenses and integration activities related to the PHI acquisition.
(e) Adjustment to exclude charges to earnings related to the impairment of the ExGen Texas Power, LLC (EGTP) assets held for sale in 2017, and in 2018 the impairment of certain wind projects at Generation.
(f) Adjustment to exclude accelerated depreciation and amortization expenses and one-time charges associated with Generation's previous decision to early retire the Three Mile Island nuclear facility in 2017. In 2018, primarily reflects accelerated depreciation and amortization expenses and one-time charges associated with Generation's decision to early retire the Oyster Creek nuclear facility, as well as accelerated depreciation and

amortization expenses associated with the 2017 decision to early retire the Three Mile Island nuclear facility and a loss associated with Generation's sale of Residential Solar Holding, LLC, partially offset by a gain associated with Generation's sale of its electrical contracting business.

(g) Adjustment to exclude the change in the District of Columbia statutory tax rate in 2017, and in 2018, an adjustment to the remeasurement of deferred income taxes as a result of the Tax Cuts and Jobs Act (TCJA).
(h) Adjustment to exclude adjustments to income tax, penalties and interest expenses in the second quarter of 2017 as a result of the finalization of the IRS tax computation related to Exelon’s like-kind exchange tax position.
(i) Adjustment to exclude benefits related to the favorable settlement in 2017 of certain income tax positions related to PHI's unregulated business interests.

EXELON CORPORATION
Generation Statistics

	Three Months Ended				
	June 30, 2018	March 31, 2018	December 31, 2017	September 30, 2017	June 30, 2017
Supply (in GWhs)					
Nuclear Generation					
Mid-Atlantic[(a)]	16,498	16,229	16,196	16,480	15,246
Midwest	23,100	23,597	23,922	24,362	22,592
New York[(a)(e)]	6,125	7,115	7,410	6,905	6,227
Total Nuclear Generation	45,723	46,941	47,528	47,747	44,065
Fossil and Renewables					
Mid-Atlantic	907	900	459	596	899
Midwest	321	455	430	218	417
New England	816	2,035	1,258	1,919	1,925
New York	1	1	1	1	1
ERCOT	2,303	2,949	2,684	5,703	2,315
Other Power Regions[(b)]	2,221	1,993	1,213	2,149	2,084
Total Fossil and Renewables	6,569	8,333	6,045	10,586	7,641
Purchased Power					
Mid-Atlantic	557	766	961	2,541	2,901
Midwest	223	336	355	217	413
New England	5,953	5,436	4,596	4,513	4,343
New York	—	—	—	—	—
ERCOT	2,320	1,373	1,622	1,199	1,871
Other Power Regions[(b)]	4,502	4,134	4,173	3,982	3,507
Total Purchased Power	13,555	12,045	11,707	12,452	13,035
Total Supply/Sales by Region					
Mid-Atlantic[(c)]	17,962	17,895	17,616	19,617	19,046
Midwest[(c)]	23,644	24,388	24,707	24,797	23,422
New England	6,769	7,471	5,854	6,432	6,268
New York	6,126	7,116	7,411	6,906	6,228
ERCOT	4,623	4,322	4,306	6,902	4,186
Other Power Regions[(b)]	6,723	6,127	5,386	6,131	5,591
Total Supply/Sales by Region	65,847	67,319	65,280	70,785	64,741

	Three Months Ended				
	June 30, 2018	March 31, 2018	December 31, 2017	September 30, 2017	June 30, 2017
Outage Days[(d)]					
Refueling[(e)]	94	68	60	13	125
Non-refueling[(e)]	2	6	18	15	12
Total Outage Days	96	74	78	28	137

(a) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly-owned generating plants and includes the total output of plants that are fully consolidated (e.g. CENG).
(b) Other Power Regions includes, South, West and Canada.
(c) Includes affiliate sales to PECO, BGE, Pepco, DPL and ACE in the Mid-Atlantic region and affiliate sales to ComEd in the Midwest region.
(d) Outage days exclude Salem.
(e) Includes the ownership of the FitzPatrick nuclear facility from March 31, 2017.

EXELON CORPORATION
Exelon Generation Statistics
Six Months Ended June 30, 2018 and 2017

	June 30, 2018	June 30, 2017
Supply (in GWhs)		
Nuclear Generation		
Mid-Atlantic[a]	32,727	31,790
Midwest	46,698	45,061
New York[a][d]	13,239	10,718
Total Nuclear Generation	92,664	87,569
Fossil and Renewables		
Mid-Atlantic	1,807	1,734
Midwest	776	835
New England	2,851	4,002
New York	2	2
ERCOT	5,252	3,684
Other Power Regions	4,214	3,507
Total Fossil and Renewables	14,902	13,764
Purchased Power		
Mid-Atlantic	1,323	6,299
Midwest	559	801
New England	11,390	9,407
New York	—	28
ERCOT	3,692	4,525
Other Power Regions	8,635	6,375
Total Purchased Power	25,599	27,435
Total Supply/Sales by Region[b]		
Mid-Atlantic[c]	35,857	39,823
Midwest[c]	48,033	46,697
New England	14,241	13,409
New York	13,241	10,748
ERCOT	8,944	8,209
Other Power Regions	12,849	9,882
Total Supply/Sales by Region	133,165	128,768

(a) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly-owned generating plants and includes the total output of plants that are fully consolidated (e.g. CENG).
(b) Includes affiliate sales to PECO, BGE, Pepco, DPL and ACE in the Mid-Atlantic region and affiliate sales to ComEd in the Midwest region.
(c) Includes the ownership of the FitzPatrick nuclear facility from March 31, 2017.

EXELON CORPORATION
ComEd Statistics
Three Months Ended June 30, 2018 and 2017

	Electric Deliveries (in GWhs)				Revenue (in millions)		
	2018	2017	% Change	Weather-Normal % Change	2018	2017	% Change
Rate-Regulated Electric Deliveries and Sales[(a)]							
Residential	6,557	5,919	10.8%	1.5%	$ 699	$ 644	8.5 %
Small commercial & industrial	7,735	7,437	4.0%	1.7%	357	340	5.0 %
Large commercial & industrial	7,111	6,798	4.6%	3.2%	127	119	6.7 %
Public authorities & electric railroads	286	282	1.4%	1.2%	12	11	9.1 %
Other[(b)]	—	—	n/a	n/a	213	217	(1.8)%
Total rate-regulated electric revenues[(c)]	21,689	20,436	6.1%	2.1%	1,408	1,331	5.8 %
Other Rate-Regulated Revenue[(d)]					(10)	26	(138.5)%
Total Electric Revenue					$ 1,398	$ 1,357	3.0 %
Purchased Power					$ 477	$ 378	26.2 %

				% Change	
Heating and Cooling Degree-Days	2018	2017	Normal	From 2017	From Normal
Heating Degree-Days	820	577	734	42.1%	11.7%
Cooling Degree-Days	364	263	241	38.4%	51.0%

Six Months Ended June 30, 2018 and 2017

	Electric Deliveries (in GWhs)				Revenue (in millions)		
	2018	2017	% Change	Weather-Normal % Change	2018	2017	% Change
Rate-Regulated Electric Deliveries and Sales[(a)]							
Residential	13,173	12,160	8.3%	1.2%	$ 1,416	$ 1,255	12.8 %
Small commercial & industrial	15,578	15,146	2.9%	0.6%	741	668	10.9 %
Large commercial & industrial	13,948	13,480	3.5%	2.0%	280	226	23.9 %
Public authorities & electric railroads	646	625	3.4%	2.1%	25	22	13.6 %
Other[(b)]	—	—	n/a	n/a	444	437	1.6 %
Total rate-regulated electric revenues[(c)]	43,345	41,411	4.7%	1.2%	2,906	2,608	11.4 %
Other Rate-Regulated Revenue[(d)]					4	48	(91.7)%
Total Electric Revenue					$ 2,910	$ 2,656	9.6 %
Purchased Power					$ 1,082	$ 713	51.8 %

				% Change	
Heating and Cooling Degree-Days	2018	2017	Normal	From 2017	From Normal
Heating Degree-Days	3,937	3,227	3,875	22.0%	1.6%
Cooling Degree-Days	364	263	241	38.4%	51.0%

Number of Electric Customers	2018	2017
Residential	3,631,213	3,605,731
Small Commercial & Industrial	379,862	375,976
Large Commercial & Industrial	2,002	2,009
Public Authorities & Electric Railroads	4,776	4,785
Total	4,017,853	3,988,501

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from ComEd and customers purchasing electricity from a competitive electric generation supplier, as all customers are assessed delivery charges. For customers purchasing electricity from ComEd, revenue also reflects the cost of energy and transmission.
(b) Includes revenues from transmission revenue from PJM, wholesale electric revenue and revenue from other utilities for mutual assistance programs.
(c) Includes operating revenues from affiliates totaling $5 million and $3 million for the three months ended June 30, 2018 and 2017, respectively, and $19 million and $9 million for the six months ended June 30, 2018 and 2017, respectively.
(d) Includes alternative revenue programs and late payment charges.

EXELON CORPORATION
PECO Statistics
Three Months Ended June 30, 2018 and 2017

	Electric and Natural Gas Deliveries				Revenue (in millions)		
	2018	2017	% Change	Weather-Normal % Change	2018	2017	% Change
Electric (in GWhs)							
Rate-Regulated Deliveries and Sales[(a)]							
Residential	2,946	2,809	4.9 %	3.8 %	$ 338	$ 331	2.1 %
Small commercial & industrial	1,930	1,914	0.8 %	0.4 %	97	100	(3.0)%
Large commercial & industrial	3,811	3,830	(0.5)%	0.1 %	52	57	(8.8)%
Public authorities & electric railroads	182	196	(7.1)%	(5.6)%	6	8	(25.0)%
Other[(b)]	—	—	n/a	n/a	60	51	17.6 %
Total rate-regulated electric revenues[(c)]	8,869	8,749	1.4 %	1.2 %	553	547	1.1 %
Other Rate-Regulated Revenue[(d)]					7	3	133.3 %
Total Electric Revenue					560	550	1.8 %
Natural Gas (in mmcfs)							
Rate-Regulated Gas Deliveries and Sales[(e)]							
Residential	5,889	4,577	28.7 %	0.9 %	62	50	24.0 %
Small commercial & industrial	3,598	3,039	18.4 %	0.2 %	25	22	13.6 %
Large commercial & industrial	6	5	20.0 %	12.8 %	—	—	n/a
Transportation	5,981	5,759	3.9 %	3.2 %	5	5	— %
Other[(f)]	—	—	n/a	n/a	1	3	(66.7)%
Total rate-regulated natural gas revenues[(g)]	15,474	13,380	15.7 %	1.6 %	93	80	16.3 %
Other Rate-Regulated Revenue[(d)]					$ —	$ —	n/a
Total Natural Gas Revenues					$ 93	$ 80	16.3 %
Total Electric and Natural Gas Revenues					$ 653	$ 630	3.7 %
Purchased Power and Fuel					$ 222	$ 197	12.7 %

				% Change	
Heating and Cooling Degree-Days	2018	2017	Normal	From 2017	From Normal
Heating Degree-Days	482	329	441	46.5 %	9.3 %
Cooling Degree-Days	382	415	383	(8.0)%	(0.3)%

Six Months Ended June 30, 2018 and 2017

	Electric and Natural Gas Deliveries				Revenue (in millions)		
	2018	2017	% Change	Weather-Normal % Change	2018	2017	% Change
Electric (in GWhs)							
Rate-Regulated Deliveries and Sales[a]							
Residential	6,574	6,187	6.3 %	1.7 %	$ 741	$ 713	3.9 %
Small commercial & industrial	3,958	3,890	1.7 %	(0.4)%	198	197	0.5 %
Large commercial & industrial	7,514	7,456	0.8 %	1.1 %	110	109	0.9 %
Public authorities & electric railroads	379	420	(9.8)%	(9.1)%	14	16	(12.5)%
Other[b]	—	—	n/a	n/a	122	99	23.2 %
Total rate-regulated electric revenues[c]	18,425	17,953	2.6 %	0.8 %	1,185	1,134	4.5 %
Other Rate-Regulated Revenue[d]					8	6	33.3 %
Total Electric Revenue					1,193	1,140	4.6 %
Natural Gas (in mmcfs)							
Rate-Regulated Gas Deliveries and Sales[e]							
Residential	26,463	22,689	16.6 %	0.9 %	223	192	16.1 %
Small commercial & industrial	14,016	12,130	15.5 %	2.2 %	87	77	13.0 %
Large commercial & industrial	52	13	300.0 %	291.0 %	1	—	n/a
Transportation	13,549	13,448	0.8 %	(3.3)%	11	11	— %
Other[f]	—	—	n/a	n/a	3	6	(50.0)%
Total rate-regulated natural gas revenues[g]	54,080	48,280	12.0 %	0.2 %	325	286	13.6 %
Other Rate-Regulated Revenue[d]					$ —	$ —	n/a
Total Natural Gas Revenues					$ 325	$ 286	13.6 %
Total Electric and Natural Gas Revenues					$ 1,518	$ 1,426	6.5 %
Purchased Power and Fuel					$ 555	$ 484	14.7 %

				% Change	
Heating and Cooling Degree-Days	**2018**	**2017**	**Normal**	**From 2017**	**From Normal**
Heating Degree-Days	2,879	2,423	2,885	18.8 %	(0.2)%
Cooling Degree-Days	382	415	385	(8.0)%	(0.8)%

Number of Electric Customers	2018	2017
Residential	1,474,901	1,461,931
Small Commercial & Industrial	152,152	150,783
Large Commercial & Industrial	3,114	3,105
Public Authorities & Electric Railroads	9,544	9,795
Total	1,639,711	1,625,614

Number of Natural Gas Customers	2018	2017
Residential	478,954	474,360
Small Commercial & Industrial	43,748	43,400
Large Commercial & Industrial	1	4
Transportation	767	768
Total	523,470	518,532

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from PECO and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from PECO, revenue also reflects the cost of energy and transmission.
(b) Includes revenues from transmission revenue from PJM, wholesale electric revenue and revenue from other utilities for mutual assistance programs.
(c) Includes operating revenues from affiliates totaling $2 million for both the three months ended June 30, 2018 and 2017 and $3 million for both the six months ended June 30, 2018 and 2017.
(d) Includes alternative revenue programs and late payment charges.
(e) Reflects delivery volumes and revenues from customers purchasing natural gas directly from PECO and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. For customers purchasing natural gas from PECO, revenue also reflects the cost of natural gas.
(f) Includes revenues primarily from off-system sales.
(g) Includes operating revenues from affiliates totaling less than $1 million for both the three and six months ended June 30, 2018 and 2017.

EXELON CORPORATION
BGE Statistics
Three Months Ended June 30, 2018 and 2017

	Electric and Natural Gas Deliveries				Revenue (in millions)		
	2018	2017	% Change	Weather-Normal % Change	2018	2017	% Change
Electric (in GWhs)							
Rate-Regulated Deliveries and Sales[a]							
Residential	2,717	2,629	3.3 %	0.9 %	$ 295	$ 300	(1.7)%
Small commercial & industrial	700	677	3.4 %	(3.4)%	60	58	3.4 %
Large commercial & industrial	3,396	3,373	0.7 %	(1.9)%	101	107	(5.6)%
Public authorities & electric railroads	69	72	(4.2)%	(14.2)%	7	8	(12.5)%
Other[b]	—	—	n/a	n/a	78	71	9.9 %
Total rate-regulated electric revenues[c]	6,882	6,751	1.9 %	(1.1)%	541	544	(0.6)%
Other Rate-Regulated Revenue[d]					7	27	(74.1)%
Total Electric Revenue					548	571	(4.0)%
Natural Gas (in mmcfs)							
Rate-Regulated Gas Deliveries and Sales[e]							
Residential	5,271	3,613	45.9 %	15.1 %	74	60	23.3 %
Small commercial & industrial	1,433	1,075	33.3 %	13.3 %	13	12	8.3 %
Large commercial & industrial	10,167	8,340	21.9 %	18.2 %	23	19	21.1 %
Other[f]	2,661	116	2,194.0 %	n/a	12	4	200.0 %
Total rate-regulated natural gas revenues[g]	19,532	13,144	48.6 %	16.9 %	122	95	28.4 %
Other Rate-Regulated Revenue[d]					$ (8)	$ 8	(200.0)%
Total Natural Gas Revenues					$ 114	$ 103	10.7 %
Total Electric and Natural Gas Revenues					$ 662	$ 674	(1.8)%
Purchased Power and Fuel					$ 229	$ 234	(2.1)%

				% Change	
Heating and Cooling Degree-Days	2018	2017	Normal	From 2017	From Normal
Heating Degree-Days	498	397	507	25.4%	(1.8)%
Cooling Degree-Days	299	283	256	5.7%	16.8 %

Six Months Ended June 30, 2018 and 2017

	Electric and Natural Gas Deliveries				Revenue (in millions)		
	2018	2017	% Change	Weather-Normal % Change	2018	2017	% Change
Electric (in GWhs)							
Rate-Regulated Deliveries and Sales[a]							
Residential	6,297	5,756	9.4 %	2.2 %	$ 688	$ 686	0.3 %
Small commercial & industrial	1,485	1,425	4.2 %	(0.4)%	128	128	— %
Large commercial & industrial	6,752	6,641	1.7 %	(0.7)%	207	215	(3.7)%
Public authorities & electric railroads	136	140	(2.9)%	(3.1)%	14	15	(6.7)%
Other[b]	—	—	n/a	n/a	156	138	13.0 %
Total rate-regulated electric revenues[c]	14,670	13,962	5.1 %	0.5 %	1,193	1,182	0.9 %
Other Rate-Regulated Revenue[d]					13	55	(76.4)%
Total Electric Revenue					1,206	1,237	(2.5)%
Natural Gas (in mmcfs)							
Rate-Regulated Gas Deliveries and Sales[e]							
Residential	27,046	21,730	24.5 %	4.0 %	298	245	21.6 %
Small commercial & industrial	6,207	4,853	27.9 %	8.2 %	47	42	11.9 %
Large commercial & industrial	25,817	22,816	13.2 %	7.2 %	70	64	9.4 %
Other[f]	8,039	2,395	235.7 %	n/a	40	17	135.3 %
Total rate-regulated natural gas revenues[g]	67,109	51,794	29.6 %	5.8 %	455	368	23.6 %
Other Rate-Regulated Revenue[d]					$ (22)	$ 20	(210.0)%
Total Natural Gas Revenues					$ 433	$ 388	11.6 %
Total Electric and Natural Gas Revenues					$ 1,639	$ 1,625	0.9 %
Purchased Power and Fuel					$ 609	$ 584	4.3 %

Heating and Cooling Degree-Days	2018	2017	Normal	% Change From 2017	% Change From Normal
Heating Degree-Days	2,939	2,460	2,898	19.5%	1.4%
Cooling Degree-Days	299	283	256	5.7%	16.8%

Number of Electric Customers	2018	2017
Residential	1,163,789	1,154,330
Small Commercial & Industrial	113,745	113,329
Large Commercial & Industrial	12,183	12,113
Public Authorities & Electric Railroads	268	276
Total	1,289,985	1,280,048

Number of Natural Gas Customers	2018	2017
Residential	630,714	624,392
Small Commercial & Industrial	38,274	38,211
Large Commercial & Industrial	5,900	5,809
Total	674,888	668,412

(a) Reflects delivery volumes and revenue from customers purchasing electricity directly from BGE and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from BGE, revenue also reflects the cost of energy and transmission.
(b) Includes revenues from transmission revenue from PJM, wholesale electric revenue and revenue from other utilities for mutual assistance programs.
(c) Includes operating revenues from affiliates totaling $2 million and $1 million for the three months ended June 30, 2018 and 2017, respectively, and $3 million for both the six months ended June 30, 2018 and 2017.
(d) Includes alternative revenue programs and late payment charges.
(e) Reflects delivery volumes and revenues from customers purchasing natural gas directly from BGE and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. For customers purchasing natural gas from BGE, revenue also reflects the cost of natural gas.
(f) Includes revenues primarily from off-system sales.
(g) Includes operating revenues from affiliates totaling $4 million and $2 million for the three months ended June 30, 2018 and 2017, respectively, and $9 million and $5 million for the six months ended June 30, 2018 and 2017, respectively.

EXELON CORPORATION
PEPCO Statistics
Three Months Ended June 30, 2018 and 2017

	Electric Deliveries (in GWhs)				Revenue (in millions)		
	2018	2017	% Change	Weather - Normal % Change	2018	2017	% Change
Rate-Regulated Deliveries and Sales[a]							
Residential	1,799	1,757	2.4 %	(5.6)%	$ 228	$ 223	2.2 %
Small commercial & industrial	309	326	(5.2)%	(7.9)%	33	34	(2.9)%
Large commercial & industrial	3,693	3,675	0.5 %	(1.6)%	212	193	9.8 %
Public authorities & electric railroads	174	172	1.2 %	1.2 %	9	8	12.5 %
Other[b]	—	—	n/a	n/a	49	49	— %
Total rate-regulated electric revenues[c]	5,975	5,930	0.8 %	(3.1)%	531	507	4.7 %
Other Rate-Regulated Revenue[d]					(8)	7	(214.3)%
Total Electric Revenue					523	514	1.8 %
Purchased Power					$ 140	$ 143	(2.1)%

				% Change	
Heating and Cooling Degree-Days	2018	2017	Normal	From 2017	From Normal
Heating Degree-Days	327	207	307	58.0%	6.5%
Cooling Degree-Days	575	546	486	5.3%	18.3%

Six Months Ended June 30, 2018 and 2017

	Electric Deliveries (in GWhs)				Revenue (in millions)		
	2018	2017	% Change	Weather - Normal % Change	2018	2017	% Change
Rate-Regulated Deliveries and Sales[a]							
Residential	4,082	3,757	8.7 %	(0.6)%	$ 486	$ 460	5.7 %
Small commercial & industrial	655	652	0.5 %	(3.0)%	65	68	(4.4)%
Large commercial & industrial	7,363	7,160	2.8 %	0.8 %	402	382	5.2 %
Public authorities & electric railroads	350	362	(3.3)%	(3.6)%	16	16	— %
Other[b]	—	—	n/a	n/a	98	96	2.1 %
Total rate-regulated electric revenues[c]	12,450	11,931	4.4 %	— %	1,067	1,022	4.4 %
Other Rate-Regulated Revenue[d]					13	23	(43.5)%
Total Electric Revenue					1,080	1,045	3.3 %
Purchased Power					$ 322	$ 309	4.2 %

				% Change	
Heating and Cooling Degree-Days	2018	2017	Normal	From 2017	From Normal
Heating Degree-Days	2,456	1,955	2,436	25.6%	0.8%
Cooling Degree-Days	578	550	489	5.1%	18.2%

Number of Electric Customers	2018	2017
Residential	798,741	787,708
Small Commercial & Industrial	53,460	53,393
Large Commercial & Industrial	21,846	21,767
Public Authorities & Electric Railroads	147	139
Total	874,194	863,007

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from Pepco and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from Pepco, revenue also reflects the cost of energy and transmission.
(b) Includes revenues from transmission revenue from PJM, wholesale electric revenue and revenue from other utilities for mutual assistance programs.
(c) Includes operating revenues from affiliates totaling $2 million and $1 million for the three months ended June 30, 2018 and 2017, respectively, and $3 million for both six months ended June 30, 2018 and 2017.
(d) Includes alternative revenue programs and late payment charges.

EXELON CORPORATION
DPL Statistics
Three Months Ended June 30, 2018 and 2017

	Electric and Natural Gas Deliveries				Revenue (in millions)		
	2018	2017	% Change	Weather - Normal % Change	2018	2017	% Change
Electric (in GWhs)							
Rate-Regulated Deliveries and Sales[a]							
Residential	1,115	1,045	6.7 %	2.1 %	$ 142	$ 145	(2.1)%
Small Commercial & industrial	536	526	1.9 %	0.8 %	44	45	(2.2)%
Large Commercial & industrial	1,187	1,131	5.0 %	4.0 %	25	26	(3.8)%
Public authorities & electric railroads	10	12	(16.7)%	(16.7)%	3	4	(25.0)%
Other[b]	—	—	n/a	n/a	41	39	5.1 %
Total rate-regulated electric revenues[c]	2,848	2,714	4.9 %	2.6 %	255	259	(1.5)%
Other Rate-Regulated Revenue[d]					6	1	500.0 %
Total Electric Revenue					261	260	0.4 %
Natural Gas (in mmcfs)							
Rate-Regulated Gas Deliveries and Sales[e]							
Residential	957	713	34.2 %	5.6 %	13	10	30.0 %
Small commercial & industrial	644	513	25.5 %	5.8 %	8	5	60.0 %
Large commercial & industrial	466	453	2.9 %	2.9 %	1	2	(50.0)%
Transportation	1,420	1,324	7.3 %	4.9 %	4	2	100.0 %
Other[f]	—	—	n/a	n/a	2	3	(33.3)%
Total rate-regulated natural gas revenues	3,487	3,003	16.1 %	5.0 %	28	22	27.3 %
Other Rate-Regulated Revenue[d]					—	—	n/a
Total Natural Gas Revenues					28	22	27.3 %
Total Electric and Natural Gas Revenues					$ 289	$ 282	2.5 %
Purchased Power and Fuel					$ 114	$ 113	0.9 %

Electric Service Territory				% Change	
Heating and Cooling Degree-Days	2018	2017	Normal	From 2017	From Normal
Heating Degree-Days	460	358	468	28.5%	(1.7)%
Cooling Degree-Days	372	361	334	3.0%	11.4 %

Gas Service Territory				% Change	
Heating Degree-Days	2018	2017	Normal	From 2017	From Normal
Heating Degree-Days	481	372	498	29.3%	(3.4)%

Six Months Ended June 30, 2018 and 2017

	Electric and Natural Gas Deliveries				Revenue (in millions)		
	2018	2017	% Change	Weather - Normal % Change	2018	2017	% Change
Electric (in GWhs)							
Rate-Regulated Deliveries and Sales[a]							
Residential	2,666	2,404	10.9 %	2.9 %	$ 333	$ 321	3.7 %
Small Commercial & industrial	1,105	1,057	4.5 %	2.3 %	90	89	1.1 %
Large Commercial & industrial	2,266	2,195	3.2 %	1.9 %	48	50	(4.0)%
Public authorities & electric railroads	22	25	(12.0)%	(12.0)%	7	8	(12.5)%
Other[b]	—	—	n/a	n/a	82	78	5.1 %
Total rate-regulated electric revenues[c]	6,059	5,681	6.7 %	2.4 %	560	546	2.6 %
Other Rate-Regulated Revenue[d]					7	11	(36.4)%
Total Electric Revenue					567	557	1.8 %
Natural Gas (in mmcfs)							
Rate-Regulated Gas Deliveries and Sales[e]							
Residential	5,442	4,453	22.2 %	4.0 %	60	50	20.0 %
Small commercial & industrial	2,521	2,197	14.7 %	(2.4)%	26	22	18.2 %
Large commercial & industrial	984	960	2.5 %	2.5 %	5	4	25.0 %
Transportation	3,633	3,493	4.0 %	0.6 %	9	7	28.6 %
Other[f]	—	—	n/a	n/a	6	4	50.0 %
Total rate-regulated natural gas revenues	12,580	11,103	13.3 %	1.5 %	106	87	21.8 %
Other Rate-Regulated Revenue[d]					—	—	n/a
Total Natural Gas Revenues					106	87	21.8 %
Total Electric and Natural Gas Revenues					$ 673	$ 644	4.5 %
Purchased Power and Fuel					$ 291	$ 270	7.8 %

Electric Service Territory				% Change	
Heating and Cooling Degree-Days	2018	2017	Normal	From 2017	From Normal
Heating Degree-Days	2,875	2,452	2,875	17.3%	—%
Cooling Degree-Days	373	361	336	3.3%	11.0%

Gas Service Territory				% Change	
Heating Degree-Days	2018	2017	Normal	From 2017	From Normal
Heating Degree-Days	2,985	2,543	3,000	17.4%	(0.5)%

Number of Electric Customers	2018	2017	Number of Natural Gas Customers	2018	2017
Residential	461,596	458,361	Residential	122,754	121,166
Small Commercial & Industrial	61,189	60,499	Small Commercial & Industrial	9,810	9,725
Large Commercial & Industrial	1,362	1,410	Large Commercial & Industrial	18	18
Public Authorities & Electric Railroads	624	636	Transportation	154	155
Total	524,771	520,906	Total	132,736	131,064

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from DPL and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from DPL, revenue also reflects the cost of energy and transmission.
(b) Includes revenues from transmission revenue from PJM, wholesale electric revenue and revenue from other utilities for mutual assistance programs.
(c) Includes operating revenues from affiliates totaling $2 million for both three months ended June 30, 2018 and 2017 and $4 million for both six months ended June 30, 2018 and 2017.
(d) Includes alternative revenue programs and late payment charges.
(e) Reflects delivery volumes and revenues from customers purchasing natural gas directly from DPL and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. For customers purchasing natural gas from DPL, revenue also reflects the cost of natural gas.
(f) Includes revenues primarily from off-system sales.

EXELON CORPORATION
ACE Statistics
Three Months Ended June 30, 2018 and 2017

	Electric Deliveries (in GWhs)				Revenue (in millions)		
	2018	2017	% Change	Weather - Normal % Change	2018	2017	% Change
Rate-Regulated Deliveries and Sales[(a)]							
Residential	825	814	1.4%	(2.2)%	$ 135	$ 130	3.8 %
Small Commercial & industrial	309	302	2.3%	0.3 %	38	40	(5.0)%
Large Commercial & industrial	872	853	2.2%	1.4 %	45	49	(8.2)%
Public Authorities & Electric Railroads	11	11	—%	— %	4	4	— %
Other[(b)]	—	—	n/a	n/a	44	44	— %
Total rate-regulated electric revenues[(c)]	2,017	1,980	1.9%	(0.3)%	266	267	(0.4)%
Other Rate-Regulated Revenue[(d)]					(1)	3	(133.3)%
Total Electric Revenue					265	270	(1.9)%
Purchased Power					$ 128	$ 128	— %

				% Change	
Heating and Cooling Degree-Days	2018	2017	Normal	From 2017	From Normal
Heating Degree-Days	515	435	554	18.4%	(7.0)%
Cooling Degree-Days	354	324	292	9.3%	21.2 %

Six Months Ended June 30, 2018 and 2017

	Electric Deliveries (in GWhs)				Revenue (in millions)		
	2018	2017	% Change	Weather - Normal % Change	2018	2017	% Change
Rate-Regulated Deliveries and Sales[(a)]							
Residential	1,815	1,693	7.2%	2.9%	$ 295	$ 272	8.5 %
Small Commercial & industrial	623	585	6.5%	4.6%	75	76	(1.3)%
Large Commercial & industrial	1,696	1,618	4.8%	4.0%	91	94	(3.2)%
Public Authorities & Electric Railroads	26	24	8.3%	8.3%	7	7	— %
Other[(b)]	—	—	n/a	n/a	110	86	27.9 %
Total rate-regulated electric revenues[(c)]	4,160	3,920	6.1%	3.6%	578	535	8.0 %
Other Rate-Regulated Revenue[(d)]					(3)	9	(133.3)%
Total Electric Revenue					575	544	5.7 %
Purchased Power					$ 289	$ 266	8.6 %

				% Change	
Heating and Cooling Degree-Days	2018	2017	Normal	From 2017	From Normal
Heating Degree-Days	2,927	2,585	3,028	13.2%	(3.3)%
Cooling Degree-Days	354	324	293	9.3%	20.8 %

Number of Electric Customers	2018	2017
Residential	489,050	486,173
Small Commercial & Industrial	61,134	61,013
Large Commercial & Industrial	3,590	3,744
Public Authorities & Electric Railroads	654	629
Total	554,428	551,559

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from ACE and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from ACE, revenue also reflects the cost of energy and transmission.
(b) Includes revenues from transmission revenue from PJM, wholesale electric revenue and revenue from other utilities for mutual assistance programs.
(c) Includes operating revenues from affiliates totaling $1 million both the three months ended June 30, 2018 and 2017 and $2 million and $1 million for the six months ended June 30, 2018 and 2017 respectively.
(d) Includes alternative revenue programs and late payment charges.

Earnings Conference Call
2nd Quarter 2018

August 2, 2018

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 2017 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 23, Commitments and Contingencies; (2) Exelon's Second Quarter 2018 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 17; and (2) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this press release. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this presentation.

Non-GAAP Financial Measures

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

- ***Adjusted operating earnings*** exclude certain costs, expenses, gains and losses and other specified items, including mark-to-market adjustments from economic hedging activities, unrealized gains and losses from nuclear decommissioning trust fund investments, merger and integration related costs, impairments of certain long-lived assets, certain amounts associated with plant retirements and divestitures, costs related to a cost management program and other items as set forth in the reconciliation in the Appendix
- ***Adjusted operating and maintenance expense*** excludes regulatory operating and maintenance costs for the utility businesses and direct cost of sales for certain Constellation and Power businesses, decommissioning costs that do not affect profit and loss, the impact from operating and maintenance expense related to variable interest entities at Generation, EDF's ownership of O&M expenses, and other items as set forth in the reconciliation in the Appendix
- ***Total gross margin*** is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, 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

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Non-GAAP Financial Measures Continued

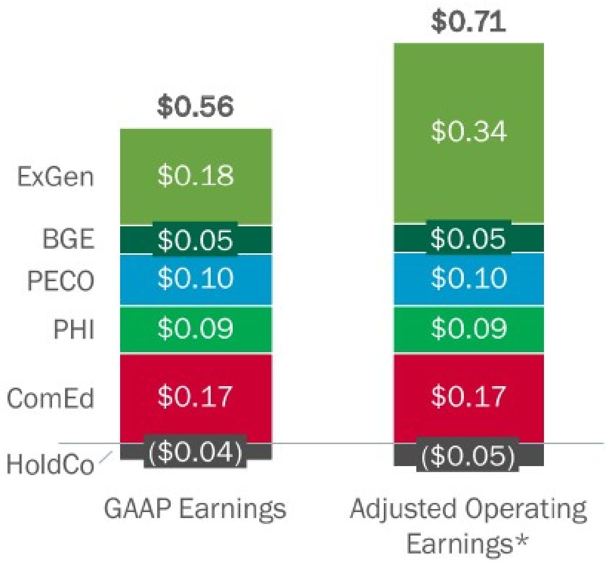
This information is intended to enhance an investor's overall understanding of period over period financial results and provide an indication of Exelon's baseline operating performance by excluding items that are considered by management to be not directly related to the ongoing operations of the business. 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 42 of this presentation.

2nd Quarter Results

Q2 2018 EPS Results(1,2)



- GAAP earnings were $0.56/share in Q2 2018 vs. $0.10/share in Q2 2017
- Adjusted operating earnings* were $0.71/share in Q2 2018 vs. $0.56/share in Q2 2017, exceeding our guidance range of $0.55-$0.65/share

(1) Amounts may not add due to rounding
(2) Certain immaterial prior year amounts in the Registrants' Consolidated Statements of Operations and Comprehensive Income have been recast to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018

Operating Highlights

Exelon Utilities Operational Metrics

Operations	Metric	Q2 2018 BGE	Q2 2018 ComEd	Q2 2018 PECO	Q2 2018 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	Percent of Calls Responded to in <1 Hour		No Gas Operations		

- Continued top tier reliability performance, with top decile performance in CAIDI and gas odor
- Customer performance metrics continue to be strong across all utilities

Q1	Q2
Q3	Q4

Exelon Generation Operational Performance

Exelon Nuclear Fleet[2]

- Continued best in class performance across our Nuclear fleet:
  - Q2 2018 Nuclear Capacity Factor: 93.2%
  - 96 outage days in Q2 2018 compared to 137 in Q2 2017

Fossil and Renewable Fleet

- Strong performance across our Fossil and Renewable fleet:
  - Q2 2018 Renewables energy capture: 95.1%
  - Q2 2018 Power dispatch match: 97.8%

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

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Tax Reform Producing Significant Customer Bill Savings

DPL

- DPL has filed to provide over **$40M** in annual distribution tax savings to customers
- DPL has also filed to provide **$12M** in annual transmission tax savings, in addition to another **$4M** pending approval from FERC

ACE

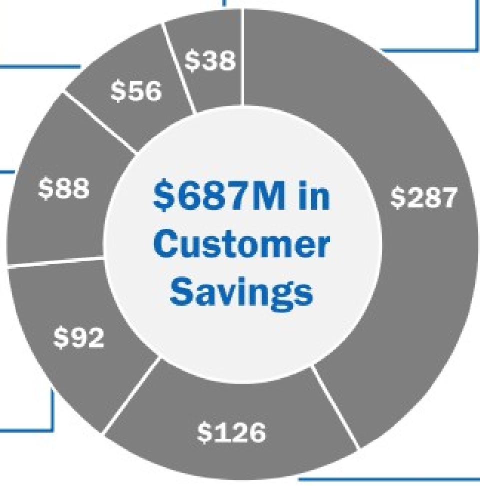
- ACE has filed to provide **$23M** in annual distribution tax savings to customers
- ACE has also filed to provide **$11M** in annual transmission tax savings, in addition to another **$4M** pending approval from FERC

ComEd

- ComEd has filed to provide **$201M** in annual distribution tax savings to customers
- ComEd has also filed to provide **$69M** in annual transmission tax savings, in addition to another **$17M** pending approval from FERC

Pepco

- Pepco has filed to provide over **$70M** in annual distribution tax savings to customers
- Pepco has also filed to provide **$13M** in annual transmission tax savings, in addition to another **$5M** pending approval from FERC



BGE

- BGE has filed to provide **$103M** in annual distribution tax savings to customers
- BGE has also filed to provide **$18M** in annual transmission tax savings, in addition to another **$5M** pending approval from FERC

PECO

- PECO has filed to provide **$72M** in annual distribution tax savings to customers
- PECO has also filed to provide **$20M** in annual transmission tax savings

Utility customers across our jurisdictions will benefit from tax reform, saving over $675M annually through planned and approved transmission and distribution bill adjustments

Constructive Legislation for Our Utilities

Delaware

- On June 14, Governor Carney signed Senate Bill 80, which enacted the Distribution System Investment Charge (DSIC) legislation
- The DSIC tracker establishes a system improvement charge that provides a mechanism to recover infrastructure investments, allowing for:
  - Gradual rate increases; and
  - Limiting frequency of rate cases
- DPL DE expects to make its first filing under the DSIC rules in Q4 2018, with the new charge appearing on customer bills by Q1 2019

Pennsylvania

- On June 28, Governor Wolf signed House Bill (HB) 1782
- HB 1782 authorizes the PA PUC to review and approve utility-proposed alternative rate mechanisms
  - Alternative methods include options such as decoupling mechanisms, formula rates, multi-year rate plans, and performance based rates
- HB 1782 will ensure that our utilities and state regulators have a full range of options to consider to meet PA's future infrastructure needs

Recent passage of legislation in DE and PA will support needed infrastructure investment that includes utility of the future initiatives to the benefit of our customers, while also allowing for timely recovery on those investments

ZEC & Energy Policy Updates

ZEC Updates

New Jersey:

- Governor Murphy signed the NJ ZEC bill into law on May 23rd
- Implementation of the program is scheduled to be completed around the end of Q1 2019

Illinois:

- Oral arguments for the 7th Circuit occurred on January 3, 2018, with requests for supplemental briefings
- Supplemental briefings were filed on January 26, 2018
- Court issued order on February 21, 2018, inviting the U.S. Government to provide its views
- U.S. Solicitor General responded in support of the case on May 29th
- Currently awaiting court decision

New York:

- Oral arguments for the 2nd Circuit occurred on March 12, 2018
- No outstanding items following oral arguments
- Currently awaiting court decision

FERC Capacity Order

- On June 29, 2018, FERC issued an order rejecting both capacity repricing and MOPREx, but finding that the existing tariff is not just and reasonable
- FERC established a paper hearing proceeding to develop a new, two-part approach:
  - **Alternative FRR**: enables states to establish asset specific FRR arrangements that would allow them to compensate those assets directly and remove the associated load from the RPM auction
  - **MOPR**: if FRR is not elected, an expanded MOPR would apply to all existing and new resources with out-of-market support, with no or few exceptions
- FERC has required comments within 60 days, with replies 30 days later
- FERC aims to reach a final decision by January 4, 2019

PJM Price Formation

- PJM fast start proceeding was initiated by FERC (Docket No. EL18-34) and has now been fully briefed
- FERC has committed to providing a decision in September 2018
  - If FERC approves in September, without changes, then PJM could implement the changes in winter 2018/2019
- After assessing FERC's fast start decision, PJM will determine path forward for full integer relaxation
  - PJM has not set a definitive timeline for stakeholder deliberations
- Deliberations regarding scarcity pricing and reserves reforms are ongoing in Q3 and Q4 for early 2019 action

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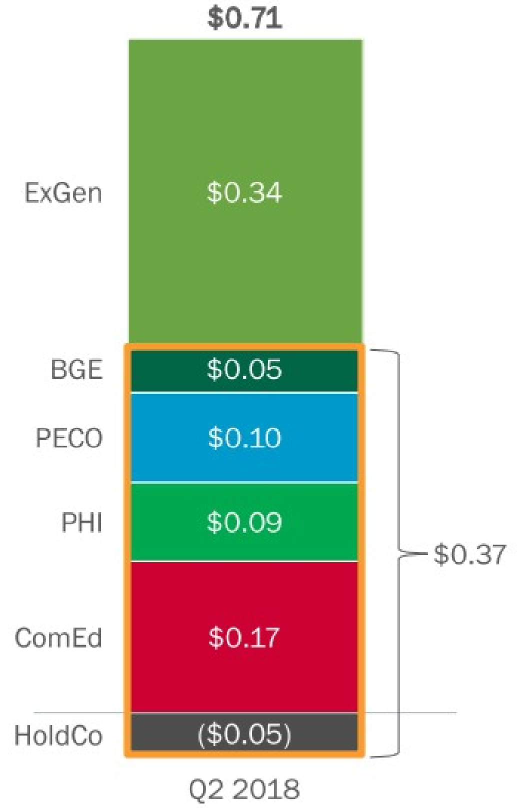
2nd Quarter Adjusted Operating Earnings* Drivers

Q2 2018 Adjusted Operating EPS* Results



Q2 2018 vs. Guidance of $0.55 - $0.65

Exelon Utilities

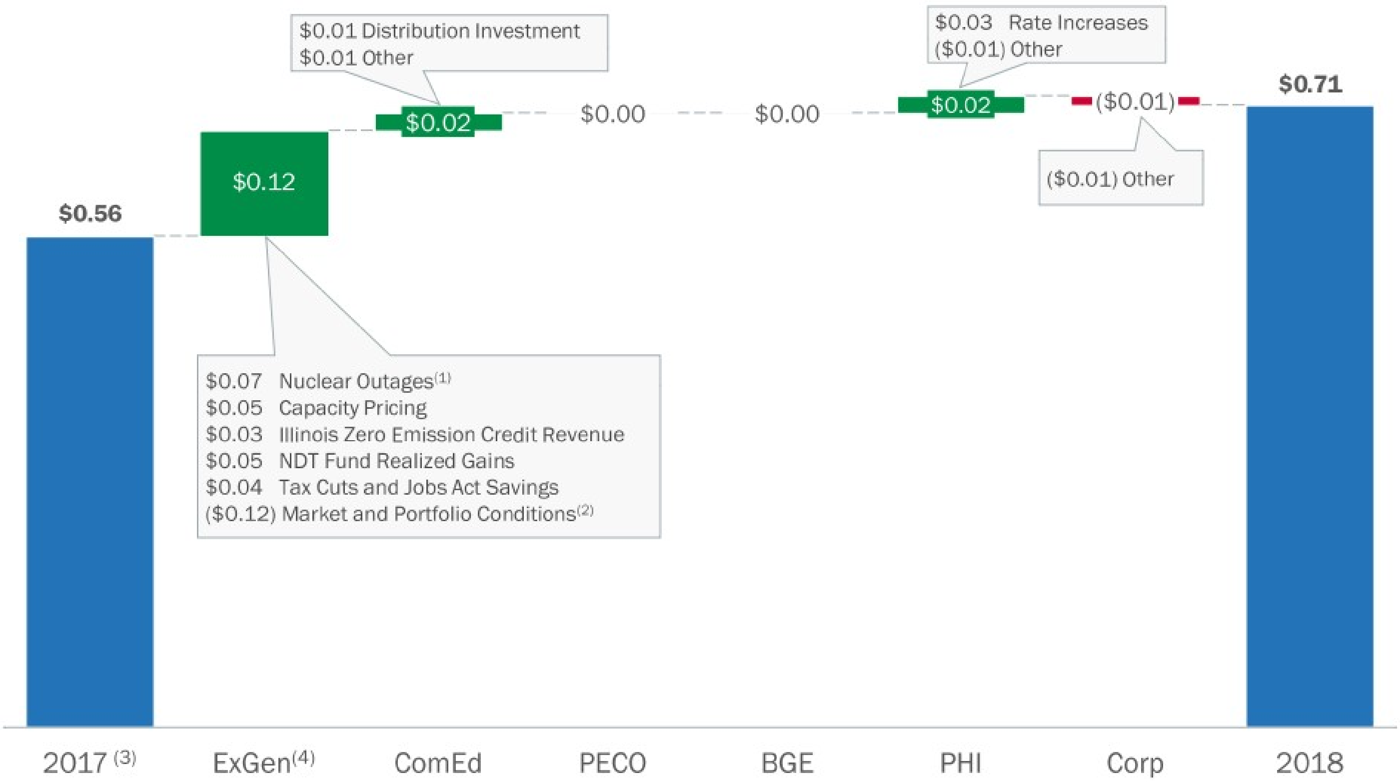
- ↑ Higher distribution and transmission revenue
- ↑ Favorable weather

Exelon Generation

- ↑ NDT realized gains(1)
- ↑ Generation performance
- ↑ Favorable market conditions
- ↓ Higher transmission costs
- ↓ Other

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

QTD Adjusted Operating Earnings* Waterfall



Note: Amounts may not sum due to rounding

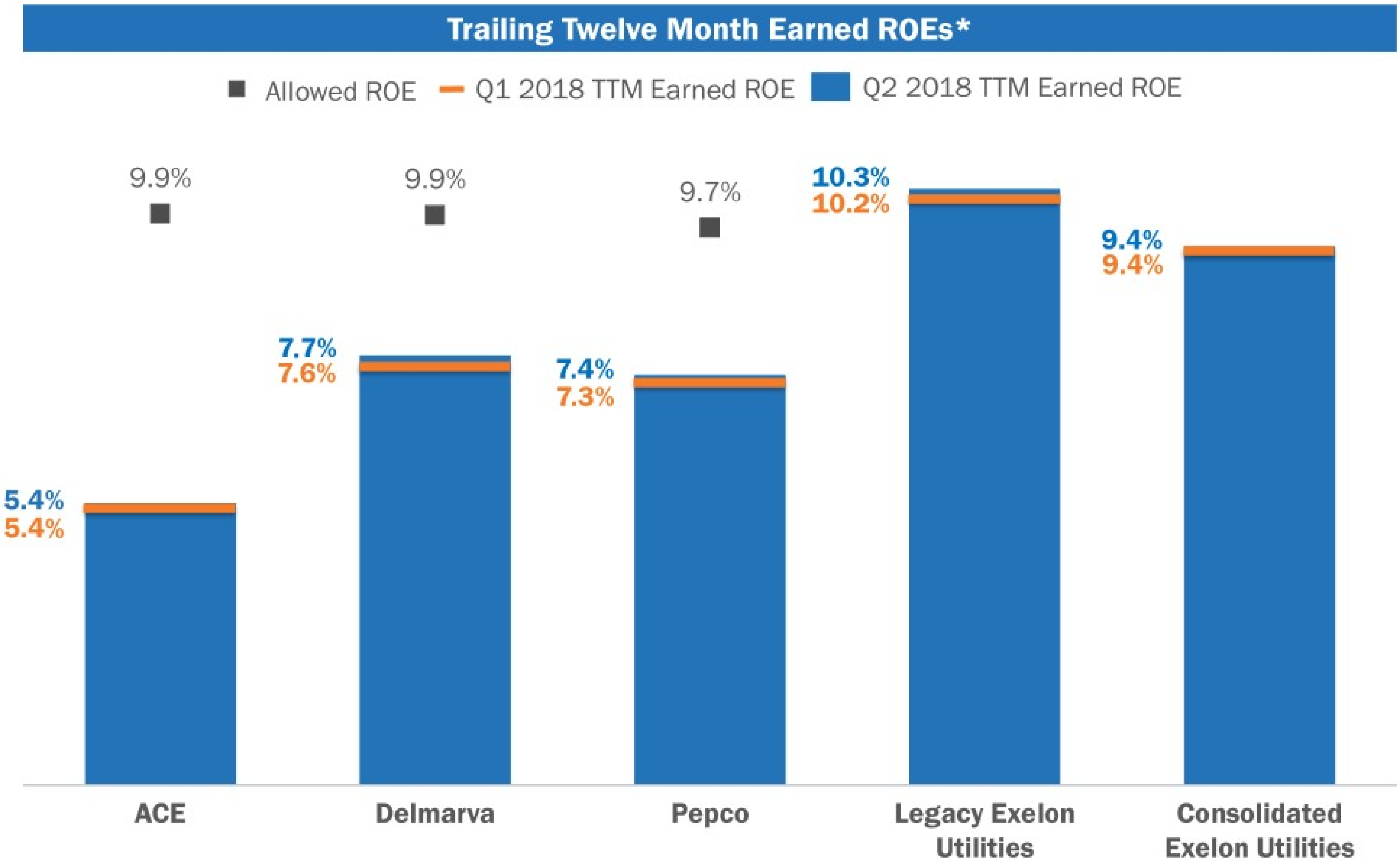
(1) Increase in volume due to a decrease in outage days in 2018; additionally operating and maintenance expense decreased due to a decrease in outage days in 2018, excluding Salem

(2) Primarily lower realized energy prices, partially offset by the favorable impact of Generation's natural gas portfolio

(3) Certain immaterial prior year amounts in the Registrants' Consolidated Statements of Operations and Comprehensive Income have been recast to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018

(4) Reflects CENG ownership at 100%

Trailing 12 Month Earned ROEs* vs Allowed ROE



Note: Represents the 12-month periods ending 3/31/2018 and 6/30/2018, respectively. Earned ROEs* represent weighted average across all lines of business (Electric Distribution, Gas Distribution and Electric Transmission).

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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
ComEd	CF		IT	RT	EH	IB RB			FO				($22.9M)[1]	8.69% / 47.11%	Dec 2018
Delmarva Electric (DE)		RT	SA EH			FO							($6.9M)[1,3]	9.70% / 50.52%	Q3 2018
Delmarva Gas (DE)		IT		RT		EH	IB RB		FO				$3.8M[1,4]	10.10% / 50.52%	Q4 2018
Pepco Electric (DC)	SA		IB			FO							($24.1M)[1,5]	9.525% / 50.44%	Q3 2018
Pepco Electric (MD)	SA	EH FO											($15.0M)[1,5]	9.50% / 50.44%	May 31, 2018
PECO Electric			IT	RT	EH	IB RB			FO				$82M[1]	10.95% / 53.39%	Dec 2018
BGE[2] Gas			CF			IT	RT	EH IB	RB	FO			$85M[6]	10.50% / 53.40%	Jan 2019

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: Based on current schedules of Illinois Commerce Commission, Maryland Public Service Commission, Delaware Public Service Commission, Public Service Commission of the District of Columbia, New Jersey Board of Public Utilities, and Pennsylvania Public Utility Commission and 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) BGE briefing schedule will be determined during or at the end of the evidentiary hearing
(3) As permitted by Delaware law, Delmarva Power implemented interim rate increases of $2.5M on October 16, 2017, and implemented $5.8M full allowable rates on March 17, 2018, subject to refund. Per non-unanimous Settlement Agreement filed on June 27, 2018. Includes tax benefits from Tax Cuts and Jobs Act.
(4) As permitted by Delaware law, Delmarva Power implemented interim rate increases of $2.5M on November 1, 2017, and implemented $3.9M full allowable rates on March 17, 2018, subject to refund. Includes tax benefits from Tax Cuts and Jobs Act.
(5) Per non-unanimous Settlement Agreement filed on April 17, 2018, for Pepco DC and April 20, 2018, for Pepco MD. Includes tax benefits from Tax Cuts and Jobs Act.
(6) Reflects $63M increase and $22M STRIDE reset

Utility CapEx Update

PECO's Gas Main and Service Replacement Program

- **Forecasted project cost:**
  - $2.3 billion of spend remaining
- **In service date:**
  - Multiple in service dates based on work plans with local townships
- **Project scope:**
  - Replace remaining 289 miles of gas services lines by end of 2022 and remaining 967 miles of main by end of 2035
  - Approximately 520 miles of mains and gas services lines have been replaced since 2010 at a cost of $381 million
  - Reduces risk on distribution system by replacing leak and break susceptible materials

BGE's Investment in Trade Point Atlantic

- **Forecasted project cost:**
  - $150 million investment in transmission & distribution over 5 years including the new 93 MW Fitzell substation
- **In service date:**
  - Fitzell substation: December 2020; electric and gas distribution investment: ongoing
- **Project scope:**
  - New substation as well as distribution infrastructure to support the new 3,100 acre Commercial & Industrial Trade Point Atlantic ("TPA") development
  - TPA is projected to generate 17,000 jobs, plus an additional 21,000 during construction; economic development is projected to be greater than $3 billion when completed[1]

(1) Economic data based on Sage Policy Group, Inc. report dated October 2016

Exelon Generation: Gross Margin Update

	June 30, 2018			Change from March 31, 2018		
Gross Margin Category ($M)[1]	**2018**	**2019**	**2020**	**2018**	**2019**	**2020**
Open Gross Margin[2,5] (including South, West, Canada hedged gross margin)	$4,700	$4,050	$3,800	$100	$100	-
Capacity and ZEC Revenues[2,5,6]	$2,300	$2,050	$1,900	-	$50	$50
Mark-to-Market of Hedges[2,3]	$400	$400	$300	$100	$(50)	$50
Power New Business / To Go	$150	$600	$800	$(200)	$(50)	$(50)
Non-Power Margins Executed	$350	$150	$100	$50	-	-
Non-Power New Business / To Go	$150	$350	$400	$(50)	-	-
Total Gross Margin*[4,5]	**$8,050**	**$7,600**	**$7,300**	**-**	**$50**	**$50**

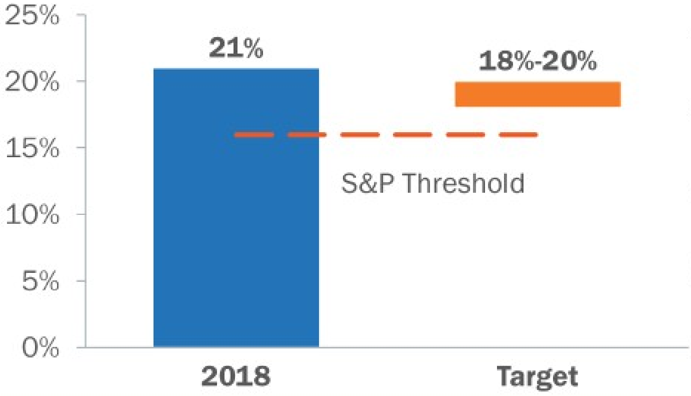
Recent Developments

- Strong second quarter executing $200M of Power New Business in 2018 and $50M in both 2019 and 2020
- Capacity and ZEC Revenues include the favorable impact of NJ ZEC revenues in 2019 and 2020
- Behind ratable hedging position reflects the upside we see in power prices
  — ~10-13% behind ratable in 2019 when considering cross commodity hedges

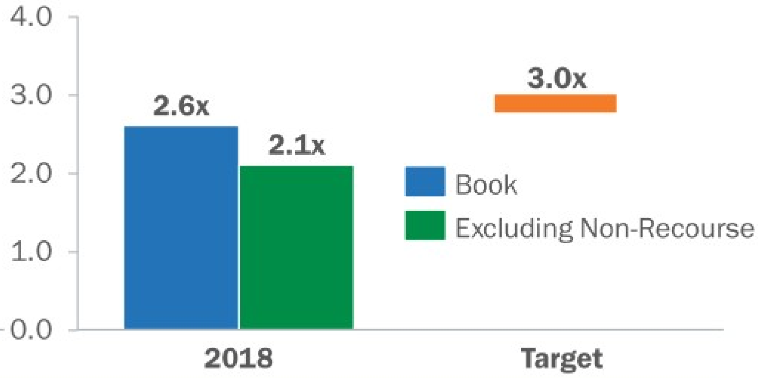
(1) Gross margin categories rounded to nearest $50M
(2) Excludes EDF's equity ownership share of the CENG Joint Venture
(3) Mark-to-Market of Hedges assumes mid-point of hedge percentages
(4) Based on June 30, 2018, market conditions
(5) Reflects Oyster Creek and TMI retirements by October 2018 and September 2019, respectively. 2018, 2019 and 2020 are adjusted for retaining Handley Generating Station.
(6) 2018 includes $150M of IL ZEC revenues associated with 2017 production. 2019 and 2020 include the favorable impact of NJ ZEC revenues.

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]	ExCorp	ExGen	ComEd	PECO	BGE	ACE	DPL	Pepco
Moody's	Baa2	Baa2	A1	Aa3	A3	A3[3]	A2	A2
S&P	BBB-	BBB	A-	A-	A-	A	A	A
Fitch	BBB[3]	BBB	A	A[3]	A-[3]	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 August 2, 2018, for Exelon, Exelon Generation and BGE and senior secured ratings for ComEd, PECO, ACE, DPL, and Pepco
(3) Exelon, PECO, and BGE are on "Positive" outlook at Fitch, and ACE is on "Positive" outlook at Moody's; all other ratings have a "Stable" outlook
(4) Exelon Corp downgrade threshold (red dotted line) is based on the S&P Exelon Corp Summary Report; represents minimum level to maintain current Issuer Credit Rating at Exelon Corp
(5) Reflects net book debt (YE debt less cash on hand) / adjusted operating EBITDA*

Exelon.

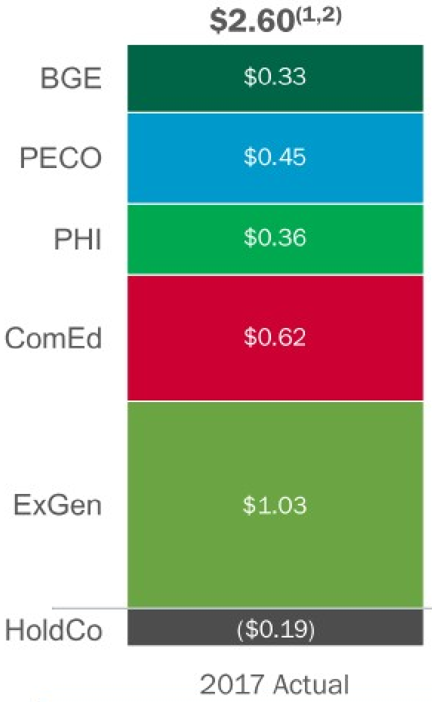
The Exelon Value Proposition

- **Regulated Utility Growth** with utility EPS rising 6-8% annually from 2017-2021 and rate base growth of 7.4%, representing an expanding majority of earnings
- **ExGen's strong free cash generation** will support utility growth while also reducing debt by ~$3B over the next 4 years
- **Optimizing ExGen value by:**
  - Seeking fair compensation for the zero-carbon attributes of our fleet;
  - Closing uneconomic plants;
  - Monetizing assets; and,
  - Maximizing the value of the fleet through our generation to load matching strategy
- **Strong balance sheet is a priority** with all businesses comfortably meeting investment grade credit metrics through the 2021 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

Additional Disclosures

2018 Adjusted Operating Earnings* Guidance



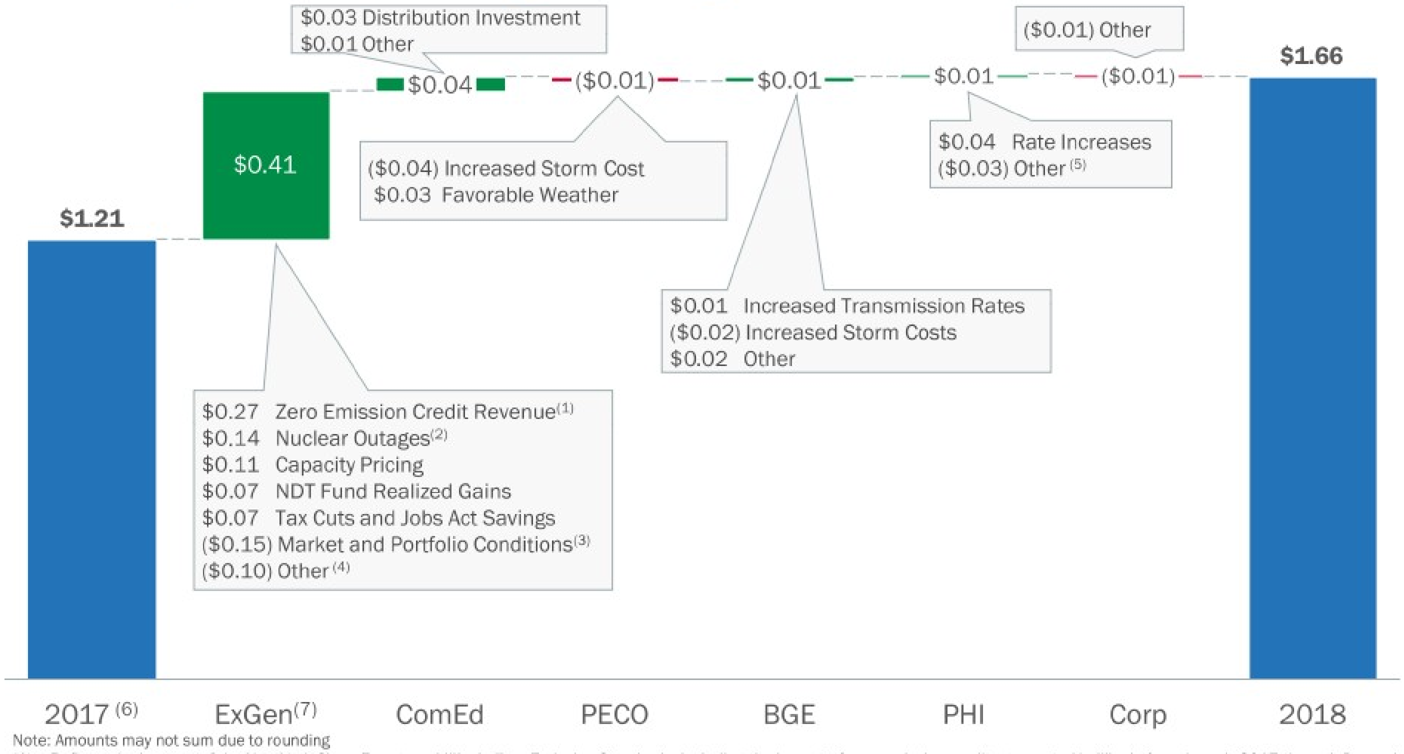
Key Year-Over-Year Drivers

- BGE: Return to normal storm (historical average) and inflation impacts
- PECO: Favorable weather and higher transmission revenue, offset by higher storm
- PHI: Higher distribution and transmission revenue and absence of 2017 FAS 109 impact, partially offset by higher depreciation
- ComEd: Increased capital investments to improve reliability in distribution and transmission
- ExGen: Capacity and ZEC revenues (including recognition of 2017 IL ZEC), and tax reform, partially offset by market conditions

Expect Q3 2018 Adjusted Operating Earnings* of $0.80 - $0.90 per share

Note: Amounts may not add due to rounding
(1) 2017 results based on 2017 average outstanding shares of 949M
(2) The Registrants' 2017 Adjusted Operating Earnings* have not been recast to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018
(3) 2018 earnings guidance based on expected average outstanding shares of 969M

YTD Adjusted Operating Earnings* Waterfall



Note: Amounts may not sum due to rounding

(1) Reflects the impacts of the New York Clean Energy and Illinois Zero Emission Standards, including the impact of zero emission credits generated in Illinois from June 1, 2017 through December 31, 2017

(2) Increase in volume due to a decrease in outage days in 2018; additionally operating and maintenance expense decreased due to a decrease in outage days in 2018, excluding Salem

(3) Primarily lower realized energy prices, the impact of the deconsolidation of EGTP and the conclusion of the Ginna Reliability Support Services Agreement, partially offset by the favorable impacts of Generation's natural gas portfolio

(4) Primarily reflects noncontrolling interest, partially offset by lower operating and maintenance expense primarily due to the impact of a supplemental NEIL insurance distribution, fewer outage days at Salem, decreased costs related to the sale of Generation's electrical contracting business

(5) Primarily due to increase in labor and contracting expense

(6) Certain immaterial prior year amounts in the Registrants' Consolidated Statements of Operations and Comprehensive Income have been recast to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018

(7) Reflects CENG ownership at 100%

Exelon.

2018 Projected Sources and Uses of Cash

($M)[1]	BGE	ComEd	PECO	PHI	Total Utilities	ExGen	Corp[8]	Exelon 2018E	Cash Balance
Beginning Cash Balance*[2]									1,450
Adjusted Cash Flow from Operations*[2]	700	1,475	625	1,100	3,900	3,975	175	8,050	
Base CapEx and Nuclear Fuel[3]	0	0	0	0	0	(1,975)	(25)	(2,000)	
Free Cash Flow*	**700**	**1,475**	**625**	**1,100**	**3,900**	**2,000**	**150**	**6,050**	
Debt Issuances	300	1,300	700	750	3,050	0	0	3,050	
Debt Retirements	0	(850)	(500)	(275)	(1,625)	0	0	(1,625)	
Project Financing	n/a	n/a	n/a	n/a	n/a	(100)	n/a	(100)	
Equity Issuance/Share Buyback	0	0	0	0	0	0	0	0	
Contribution from Parent	125	450	50	350	975	0	(950)	0	
Other Financing[4]	100	450	50	(75)	550	25	(100)	475	
Financing*[5]	**525**	**1,375**	**300**	**750**	**2,925**	**(75)**	**(1,050)**	**1,800**	
Total Free Cash Flow and Financing	**1,225**	**2,825**	**925**	**1,850**	**6,825**	**1,950**	**(900)**	**7,875**	
Utility Investment	(1,000)	(2,125)	(850)	(1,550)	(5,525)	0	0	(5,525)	
ExGen Growth[3,6]	0	0	0	0	0	(375)	0	(375)	
Acquisitions and Divestitures	0	0	0	0	0	0	0	0	
Equity Investments	0	0	0	0	0	(25)	0	(25)	
Dividend[7]	0	0	0	0	0	0	(1,325)	(1,325)	
Other CapEx and Dividend	**(1,000)**	**(2,125)**	**(850)**	**(1,550)**	**(5,525)**	**(400)**	**(1,325)**	**(7,250)**	
Total Cash Flow	**225**	**700**	**75**	**300**	**1,300**	**1,550**	**(2,250)**	**600**	
Ending Cash Balance*[2]									2,050

(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 tax sharing from the parent, money pool borrowings, debt issue costs, tax equity cash flows, capital leases, and renewable JV distributions
(5) Financing cash flow excludes intercompany dividends
(6) ExGen Growth CapEx primarily includes Texas CCGTs, W. Medway, and Retail Solar
(7) Dividends are subject to declaration by the Board of Directors
(8) Includes cash flow activity from Holding Company, eliminations, and other corporate entities

Consistent and reliable free cash flows

Operational excellence and financial discipline drives free cash flow reliability

- ✓ Generating $6.1B of free cash flow*, including $2B at ExGen and $3.9B at the Utilities

Supported by a strong balance sheet

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

- ✓ $1.4B of long-term debt at the utilities, net of refinancing, to support continued growth

Enable growth & value creation

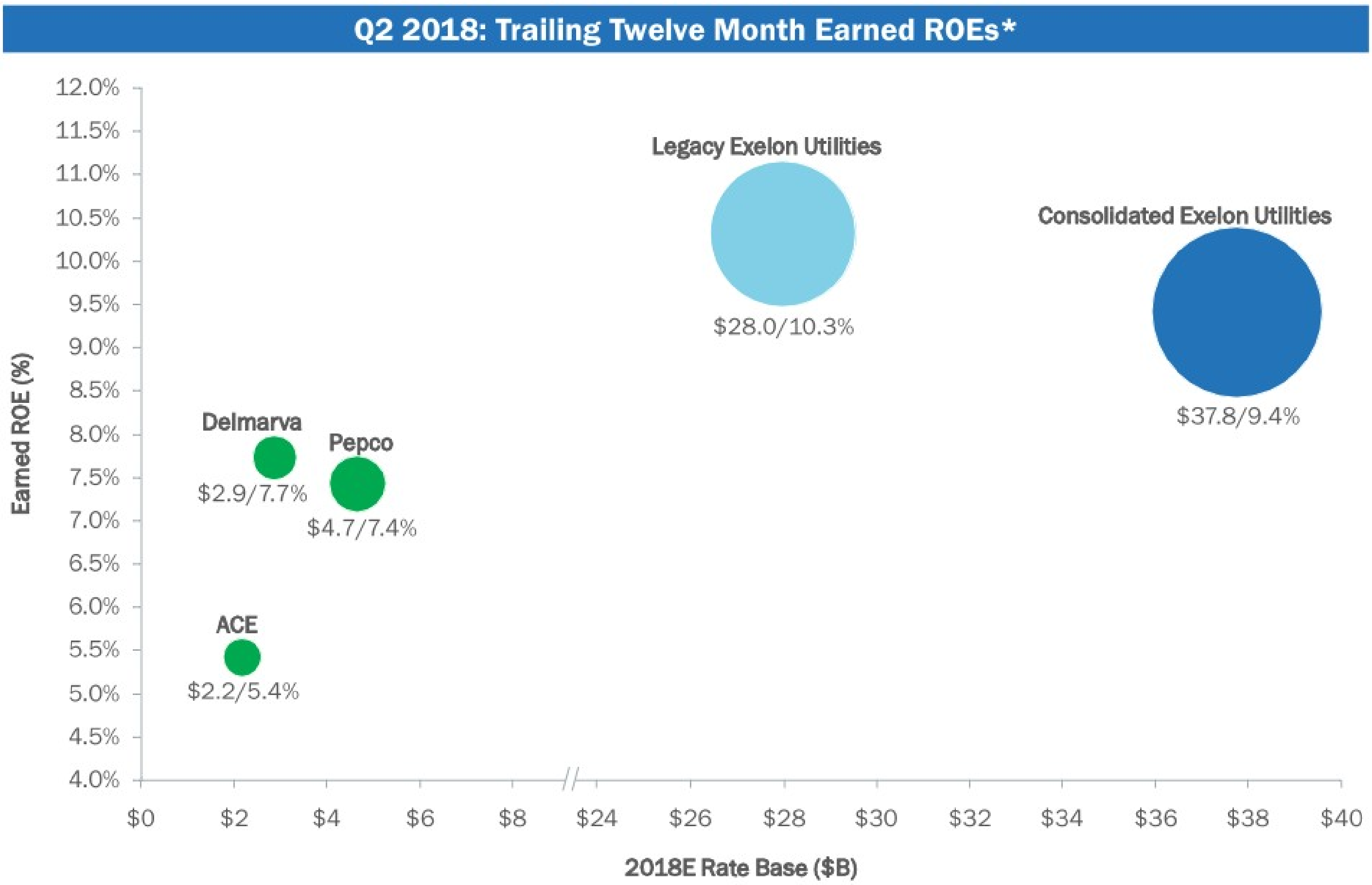
Creating value for customers, communities and shareholders

- ✓ Investing $5.9B of growth capex, with $5.5B at the Utilities and $0.4B at ExGen

Note: Numbers may not add due to rounding

Exelon.

Exelon Utilities Trailing 12 Month Earned ROEs*

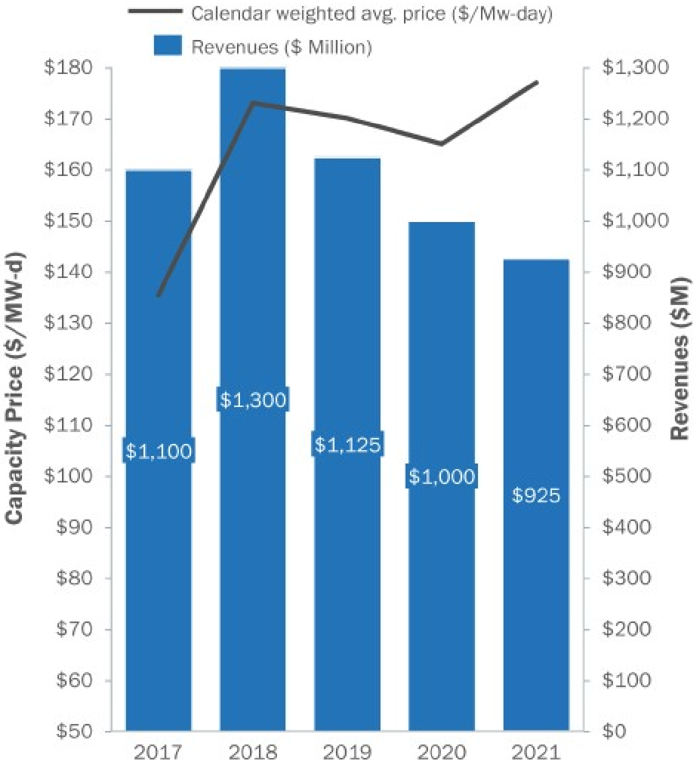


Note: Represents the 12-month period ending June 30, 2018. Earned ROEs* represent weighted average across all lines of business (Electric Distribution, Gas Distribution, and Electric Transmission). Size of bubble based on rate base.

Exelon.

Capacity Market: PJM

PJM Capacity Revenues[1,2,3]



(1) Revenues reflect capacity cleared in Base, CP transitional & incremental auctions and are for calendar years
(2) Revenues reflect owned and contracted generation
(3) Reflects 50.01% ownership at CENG
(4) Volumes at ownership and rounded

Recent BRA Results

Cleared Volumes (MW)[4]	2020/2021 CP	2020/2021 Price	2021/2022 CP	2021/2022 Price
ComEd				
Nuclear	8,075	$188	5,175	$196
Fossil/Other	-	$188	-	$196
Subtotal	**8,075**		**5,175**	
EMAAC				
Nuclear	4,350	$188	3,925	$166
Fossil/Other	2,325	$188	2,100	$166
Subtotal	**6,675**		**6,025**	
SWMAAC				
Nuclear	850	$86	850	$140
Fossil/Other	-	$86	-	$140
Subtotal	**850**		**850**	
MAAC				
Nuclear	-	$86	-	$140
Fossil/Other	225	$86	225	$140
Subtotal	**225**		**225**	
BGE				
Nuclear	-	$86	-	$200
Fossil/Other	375	$86	400	$200
Subtotal	**375**		**400**	
Rest of RTO				
Nuclear	-	$77	-	$140
Fossil/Other	-	$77	100	$140
Subtotal	**-**		**100**	
PJM Total				
Nuclear	13,275		9,950	
Fossil/Other	2,925		2,825	
Grand Total	**16,200**		**12,775**	

Exelon.

Tax Reform: Distribution-Related Customer Bill Savings

DPL

- MD PSC accepted DPL's proposal to provide **$14M** in annual tax savings to customers
- DPL has filed plans with DE PSC to provide over **$26M** in annual tax savings to customers

ACE

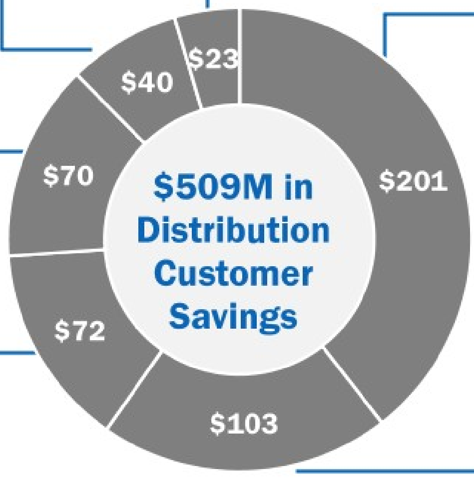
- ACE has filed a request with NJ BPU to provide **$23M** in annual tax savings to customers; expected to be approved by July
  - $2.37 savings on residential monthly bills

ComEd

- ICC approved ComEd's petition seeking approval to pass along approximately **$201M** in annual tax savings to customers
  - ~$3.00 decrease on the average residential monthly bill

Pepco

- Pepco has filed a request with the DC & MD PSC to provide over **$70M** in annual tax savings to customers
- Pepco has filed settlements which include these savings as adjusted in its proposals to the commission



BGE

- MD PSC accepted BGE's proposal to provide approximately **$103M** in annual tax savings to customers
  - $2.91 decrease on the average residential monthly electric bill
  - $5.41 decrease on the average residential combined natural gas and electric bill

PECO

- Approximately **$72M** in annual tax savings to customers

Utility customers across our jurisdictions will benefit from tax reform, saving over $500M annually through planned and approved distribution bill adjustments

Note: Includes only distribution-related customer savings amounts

Tax Reform: Transmission-Related Customer Bill Savings

DPL

- DPL has filed to provide **$12M** in annual transmission tax savings to customers. DPL also has a filing pending approval from FERC for an additional **$4M** in annual savings
  - Combined $1.00 and $1.10 decrease on the DE and MD average residential monthly bills, respectively

ACE

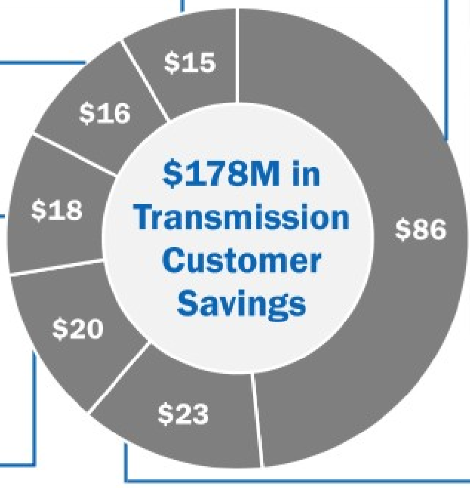
- ACE has filed to provide **$11M** in annual transmission tax savings to customers. ACE also has a filing pending approval from FERC for an additional **$4M** in annual savings
  - Combined $1.70 decrease on the average residential monthly bill

ComEd

- ComEd has filed to provide **$69M** in annual transmission tax savings to customers. ComEd also has a filing pending approval from FERC for an additional **$17M** in annual savings
  - Combined ~$0.80 decrease on the average residential monthly bill

Pepco

- Pepco has filed to provide **$13M** in annual transmission tax savings to customers. Pepco also has a filing pending approval from FERC for an additional **$5M** in annual savings
  - Combined $0.50 and $0.70 decrease on the DC and MD average residential monthly bills, respectively



BGE

- BGE has filed to provide **$18M** in annual transmission tax savings to customers. BGE also has a filing pending approval from FERC for an additional **$5M** in annual savings
  - Combined $0.88 decrease on the average residential monthly bill

PECO

- PECO has filed to provide **$20M** in annual transmission tax savings to customers
  - $0.56 decrease on the average residential monthly bill

Utility customers across our jurisdictions will benefit from tax reform, saving over $175M annually through planned and approved transmission bill adjustments

Note: Includes only transmission-related customer savings amounts

Exelon

Exelon Utilities

ComEd Distribution Rate Case Filing

	Rate Case Filing Details
Docket No.	18-0808
Test Year	January 1, 2017 – December 31, 2017
Test Period	2017 Actual Costs + 2018 Projected Plant Additions
Requested Common Equity Ratio	47.11%
Requested Rate of Return	ROE: 8.69%; ROR: 6.52%
Proposed Rate Base (Adjusted)	$10,675M
Requested Revenue Requirement Decrease	($22.9M)
Residential Total Bill % Decrease	(1%)

Notes

- April 16, 2018, ComEd filed its annual distribution formula rate update with the Illinois Commerce Commission seeking a decrease to distribution base rates
- The decrease is primarily driven by an adjustment for forecasted tax benefits resulting from federal tax reform, partially offset by continued investment in the electric grid, state tax rate increase, elimination of bonus depreciation and weather/economic impacts

Detailed Rate Case Schedule

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Filed rate case				4/16/2018								
Intervenor testimony						6/28/2018						
Rebuttal testimony							7/23/2018					
Evidentiary hearings								8/28/2018				
Initial briefs due									9/11/208			
Reply briefs due									9/25/2018			
Commission order expected												12/2018

Exelon.

Delmarva DE (Electric) Distribution Rate Case Filing

	Rate Case Filing Details
Docket No.	17-0977 – Per Settlement (Black Box)
Test Year	January 1, 2017 – December 31, 2017
Test Period	8 months actual and 4 months estimated
Requested Common Equity Ratio	50.52%[2]
Requested Rate of Return	ROE: 9.70%; ROR: 6.78%[2]
Proposed Rate Base (Adjusted)	N/A[2]
Requested Revenue Requirement Increase	($6.9M)[1,2]
Residential Total Bill % Increase	(1.2%)[2]

Notes

- August 17, 2017, Delmarva DE filed an application with Delaware Public Service Commission (DPSC) 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
- June 27, 2018, Delmarva DE filed a non-unanimous settlement agreement and requested a decrease in revenue requirement of ($6.9M)[2]

Detailed Rate Case Schedule

	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Filed rate case	8/17/2017																
Settlement agreement											6/27/2018						
Settlement support testimony											6/27/2018						
Evidentiary hearings											6/27/2018						
Commission order expected															Q3 2018		

(1) As permitted by Delaware law, Delmarva Power implemented interim rate increases of $2.5 million on October 16, 2017, and implemented $5.8M full allowable rates on March 17, 2018, subject to refund

(2) Per non-unanimous Settlement Agreement filed on June 27, 2018. Includes tax benefits from Tax Cuts and Jobs Act.

Exelon.

Delmarva DE (Gas) Distribution Rate Case Filing

	Rate Case Filing Details
Docket No.	17-0978
Test Year	January 1, 2017 – December 31, 2017
Test Period	8 months actual and 4 months estimated
Requested Common Equity Ratio	50.52%
Requested Rate of Return	ROE: 10.10%; ROR: 6.98%(2)
Proposed Rate Base (Adjusted)	$355M(2)
Requested Revenue Requirement Increase	$3.8M(1,2)
Residential Total Bill % Increase	4.3%

Notes

- August 17, 2017, Delmarva DE filed an application with Delaware Public Service Commission (DPSC) seeking an increase in gas distribution base rates
- Size of ask is driven by continued investments in gas distribution system to maintain and increase reliability and customer service
- Forward looking reliability plant additions through September 2018 ($1.2M of Revenue Requirement based on 10.10% ROE) included in revenue requirement request

Detailed Rate Case Schedule

	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Filed rate case	8/17/2017																
Intervenor testimony										5/7/2018							
Rebuttal testimony												7/6/2018					
Evidentiary hearings														9/11/2018 – 9/14/2018			
Initial briefs due															10/8/2018		
Reply briefs due															10/22/2018		
Commission order expected															Q4 2018		

(1) As permitted by Delaware law, Delmarva Power implemented interim rate increases of $2.5 million on November 1, 2017, and implemented $3.9M full allowable rates on March 17, 2018, subject to refund

(2) Updated on July 6, 2018. Includes tax benefits from Tax Cuts and Jobs Act.

Pepco DC (Electric) Distribution Rate Case Filing

	Rate Case Filing Details
Docket No.	1150 & 1151 – Per Settlement (Black Box)
Test Year	January 1, 2017 – December 31, 2017
Test Period	8 months actual and 4 months estimated
Requested Common Equity Ratio	50.44%(1)
Requested Rate of Return	ROE: 9.525%; ROR: 7.45%(1)
Proposed Rate Base (Adjusted)	N/A(1)
Requested Revenue Requirement decrease	($24.1M)(1)
Residential Total Bill % decrease	(0.7%)(1,2)

Notes

- December 19, 2017, Pepco DC filed an application with Public Service Commission of the District of Columbia (PSCDC) 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
- April 17, 2018, Pepco DC filed a non-unanimous settlement agreement and requested a decrease in revenue requirement of ($24.1M)(1)
- Commission order expected to be approved in Q3 2018

Detailed Rate Case Schedule

Event	Date (Dec – Dec)
Filed rate case	12/19/2017
Settlement agreement	4/17/2018
Settlement support testimony	5/7/2018
Reply testimony	5/18/2018
Initial briefs due	6/14/2018
Commission order expected	Q3 2018

(1) Per non-unanimous Settlement Agreement filed on April 17, 2018. Includes tax benefits from Tax Cuts and Jobs Act. Expected order is based on requested rate effective date.
(2) Modified/Extended Customer Base Rate Credit (CBRC)

Pepco MD (Electric) Distribution Rate Case Filing

	Rate Case Filing Details	Notes
Docket No.	9472 – Per Settlement (Black Box)	• January 2, 2018, Pepco MD filed an application with Maryland Public Service Commission (MDPSC) 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 • April 20, 2018, Pepco MD filed a non-unanimous settlement agreement and requested a decrease in revenue requirement of ($15.0M)(1) • May 31, 2018, MDPSC approved the settlement, which placed rates into effect on and after June 1, 2018
Test Year	January 1, 2017 – December 31, 2017	
Test Period	12 months actual update	
Requested Common Equity Ratio	50.44%(1)	
Requested Rate of Return	ROE: 9.50%; ROR: 7.44%(1)	
Proposed Rate Base (Adjusted)	N/A(1)	
Requested Revenue Requirement Increase	($15.0M)(1)	
Residential Total Bill % Increase	(1.3%)(1)	

Detailed Rate Case Schedule

	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Filed rate case		▲ 1/2/2018											
Settlement agreement					▲ 4/20/2018								
Settlement support testimony					▲ 4/27/2018								
Evidentiary hearings						▲ 5/16/2018							
Commission order						▲ 5/31/2018							

(1) Per non-unanimous Settlement Agreement filed on April 20, 2018. Includes tax benefits from Tax Cuts and Jobs Act.

PECO Distribution Rate Case Filing

	Rate Case Filing Details
Docket No.	R-2018-3000164
Test Year	January 1, 2019 – December 31, 2019
Test Period	12 Months Budget
Requested Common Equity Ratio	53.39%
Requested Rate of Return	ROE: 10.95%; ROR: 7.79%
Proposed Rate Base	$4,846M
Requested Revenue Requirement Increase	$82M(1)
Residential Total Bill % Increase	3.1%

Notes

- PECO filed an electric distribution base rate case on March 29, 2018
- Since January 1, 2016, through the Fully Projected Future Test Year (2019):
  - Relatively flat load growth
  - Operating expenses essentially flat
  - Capital investment of $1.9B
- Proposed investments would maintain strong reliability performance, strengthen system resiliency, and support physical security and cybersecurity

Detailed Rate Case Schedule

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Pre-filing notice		2/27/2018										
Filed rate case			3/29/2018									
Intervenor testimony						6/26/2018						
Rebuttal testimony							7/24/2018					
Evidentiary hearings								8/20/2018 – 8/22/2018				
Initial briefs due									9/07/2018			
Reply briefs due									9/17/2018			
Commission order expected												12/2018

(1) Reflects $153M revenue requirement less an estimated $71M in 2019 tax benefit

BGE (Gas) Distribution Rate Case Filing

	Rate Case Filing Details
Docket No.	Case No. 9484
Test Year	August 1, 2017 – July 31, 2018
Test Period	9 months actual and 3 months estimated
Requested Common Equity Ratio	53.40%
Requested Rate of Return	ROE: 10.50%; ROR: 7.42%
Proposed Rate Base (Adjusted)	$1.7B
Requested Revenue Requirement Increase	$85M(1)
Residential Total Bill % Increase	~3.5%(2)

Notes

- Case filed on June 8, 2018 seeking an increase in gas distribution revenues only
- The increase is primarily driven by infrastructure investments since 2015/2016, and includes moving revenues currently being recovered via the STRIDE surcharge into base rates

Detailed Rate Case Schedule

	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb
Filed rate case				06/08/2018								
Intervenor testimony							by 09/14/2018					
Rebuttal testimony								by 10/12/2018				
Evidentiary hearings									11/2/2018 – 11/16/2018			
Initial briefs due(3)									11/2018			
Reply briefs due										12/2018		
Commission order expected											01/04/2019	

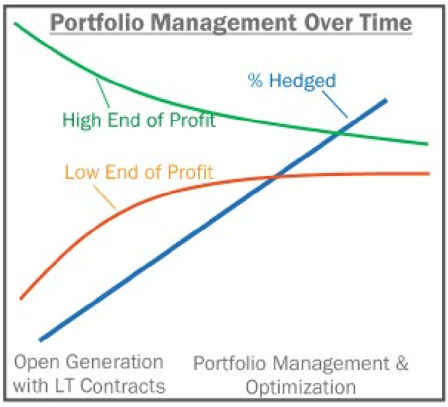
(1) Reflects $63M increase and $22M STRIDE reset
(2) Increase expressed as a percentage of a combined electric and gas residential customer total bill
(3) Briefing schedule will be determined during or at the end of the evidentiary hearing

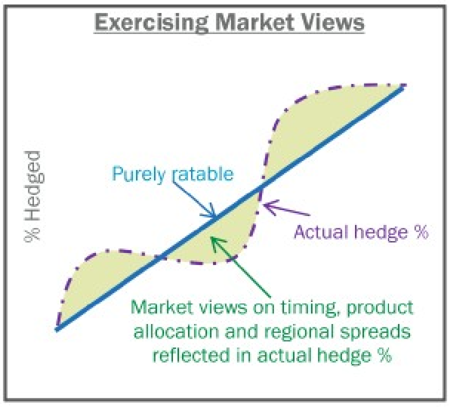
Exelon Generation Disclosures

June 30, 2018

Portfolio Management Strategy

Strategic Policy Alignment	Three-Year Ratable Hedging	Bull / Bear Program
• 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	• 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	• 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

Open Gross Margin
- Generation Gross Margin at current market prices, including ancillary revenues, nuclear fuel amortization and fossils fuels expense
- Power Purchase Agreement (PPA) Costs and Revenues
- Provided at a consolidated level for all regions (includes hedged gross margin for South, West and Canada[1])

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

MtM of Hedges[2]
- Mark-to-Market (MtM) of power, capacity and ancillary hedges, including cross commodity, retail and wholesale load transactions
- Provided directly at a consolidated level for five major regions. Provided indirectly for each of the five major regions via Effective Realized Energy Price (EREP), reference price, hedge %, expected generation.

"Power" New Business
- Retail, Wholesale planned electric sales
- Portfolio Management new business
- Mid marketing new business

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

Gross margin from other business activities

"Non Power" Executed
- Retail, Wholesale executed gas sales
- Energy Efficiency[4]
- BGE Home[4]
- Distributed Solar

"Non Power" New Business
- 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 "Non power new business" to "Non power executed" over the course of the year

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

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ExGen Disclosures

Gross Margin Category ($M)[1]	2018	2019	2020
Open Gross Margin (including South, West & Canada hedged GM)[2,5]	$4,700	$4,050	$3,800
Capacity and ZEC Revenues[2,5,6]	$2,300	$2,050	$1,900
Mark-to-Market of Hedges[2,3]	$400	$400	$300
Power New Business / To Go	$150	$600	$800
Non-Power Margins Executed	$350	$150	$100
Non-Power New Business / To Go	$150	$350	$400
Total Gross Margin*[4,5]	**$8,050**	**$7,600**	**$7,300**

Reference Prices[1]	2018	2019	2020
Henry Hub Natural Gas ($/MMBtu)	$2.93	$2.81	$2.68
Midwest: NiHub ATC prices ($/MWh)	$27.39	$26.04	$25.16
Mid-Atlantic: PJM-W ATC prices ($/MWh)	$35.93	$31.38	$30.36
ERCOT-N ATC Spark Spread ($/MWh) *HSC Gas, 7.2HR, $2.50 VOM*	$8.91	$9.70	$8.43
New York: NY Zone A ($/MWh)	$30.80	$28.21	$28.55
New England: Mass Hub ATC Spark Spread ($/MWh) *ALQN Gas, 7.5HR, $0.50 VOM*	$4.89	$5.12	$5.83

(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, 2018, market conditions
(5) Reflects Oyster Creek and TMI retirements by October 2018 and September 2019, respectively. 2018, 2019 and 2020 are adjusted for retaining Handley Generating Station.
(6) 2018 includes $150M of IL ZEC revenues associated with 2017 production. 2019 and 2020 include the favorable impact of NJ ZEC revenues.

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ExGen Disclosures

Generation and Hedges	2018	2019	2020
Exp. Gen (GWh)[1]	**199,000**	**202,400**	**193,100**
Midwest	96,700	97,100	96,700
Mid-Atlantic[2,6]	60,100	54,100	48,600
ERCOT	20,000	25,900	23,600
New York[2,6]	15,900	16,600	15,500
New England	6,300	8,700	8,700
% of Expected Generation Hedged[3]	**97%-100%**	**71%-74%**	**41%-44%**
Midwest	95%-98%	68%-71%	35%-38%
Mid-Atlantic[2,6]	102%-105%	81%-84%	50%-53%
ERCOT	98%-101%	74%-77%	45%-48%
New York[2,6]	97%-100%	75%-78%	52%-55%
New England	77%-80%	33%-36%	27%-30%
Effective Realized Energy Price ($/MWh)[4]			
Midwest	$30.00	$29.00	$29.00
Mid-Atlantic[2,6]	$39.50	$38.00	$38.00
ERCOT[5]	$1.00	$3.50	$2.50
New York[2,6]	$37.00	$33.00	$30.00
New England[5]	$6.00	$1.50	$12.00

(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 2018, 11 in 2019, and 14 in 2020 at Exelon-operated nuclear plants and Salem. Expected generation assumes capacity factors of 94.2%, 94.9% and 93.9% in 2018, 2019, and 2020, respectively at Exelon-operated nuclear plants, at ownership. These estimates of expected generation in 2019 and 2020 do not represent guidance or a forecast of future results as Exelon has not completed its planning or optimization processes for those years.
(2) Excludes EDF's equity ownership share of CENG Joint Venture
(3) Percent of expected generation hedged is the amount of equivalent sales divided by expected generation. Includes all hedging products, such as wholesale and retail sales of power, options and swaps.
(4) Effective realized energy price is representative of an all-in hedged price, on a per MWh basis, at which expected generation has been hedged. It is developed by considering the energy revenues and costs associated with our hedges and by considering the fossil fuel that has been purchased to lock in margin. It excludes uranium costs, RPM capacity and ZEC revenues, but includes the mark-to-market value of capacity contracted at prices other than RPM clearing prices including our load obligations. It can be compared with the reference prices used to calculate open gross margin in order to determine the mark-to-market value of Exelon Generation's energy hedges.
(5) Spark spreads shown for ERCOT and New England
(6) Reflects Oyster Creek and TMI retirements by October 2018 and September 2019, respectively. 2018, 2019 and 2020 are adjusted for retaining Handley Generating Station.

ExGen Hedged Gross Margin* Sensitivities

Gross Margin* Sensitivities (with existing hedges)[(1)]	2018	2019	2020
Henry Hub Natural Gas ($/MMBtu)			
+ $1/MMBtu	$25	$335	$580
- $1/MMBtu	-	$(295)	$(535)
NiHub ATC Energy Price			
+ $5/MWh	$5	$155	$305
- $5/MWh	$(5)	$(155)	$(305)
PJM-W ATC Energy Price			
+ $5/MWh	$(10)	$60	$125
- $5/MWh	$15	$(40)	$(115)
NYPP Zone A ATC Energy Price			
+ $5/MWh	-	$10	$35
- $5/MWh	-	$(15)	$(35)
Nuclear Capacity Factor			
+/- 1%	+/- $20	+/- $35	+/- $30

(1) Based on June 30, 2018, 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

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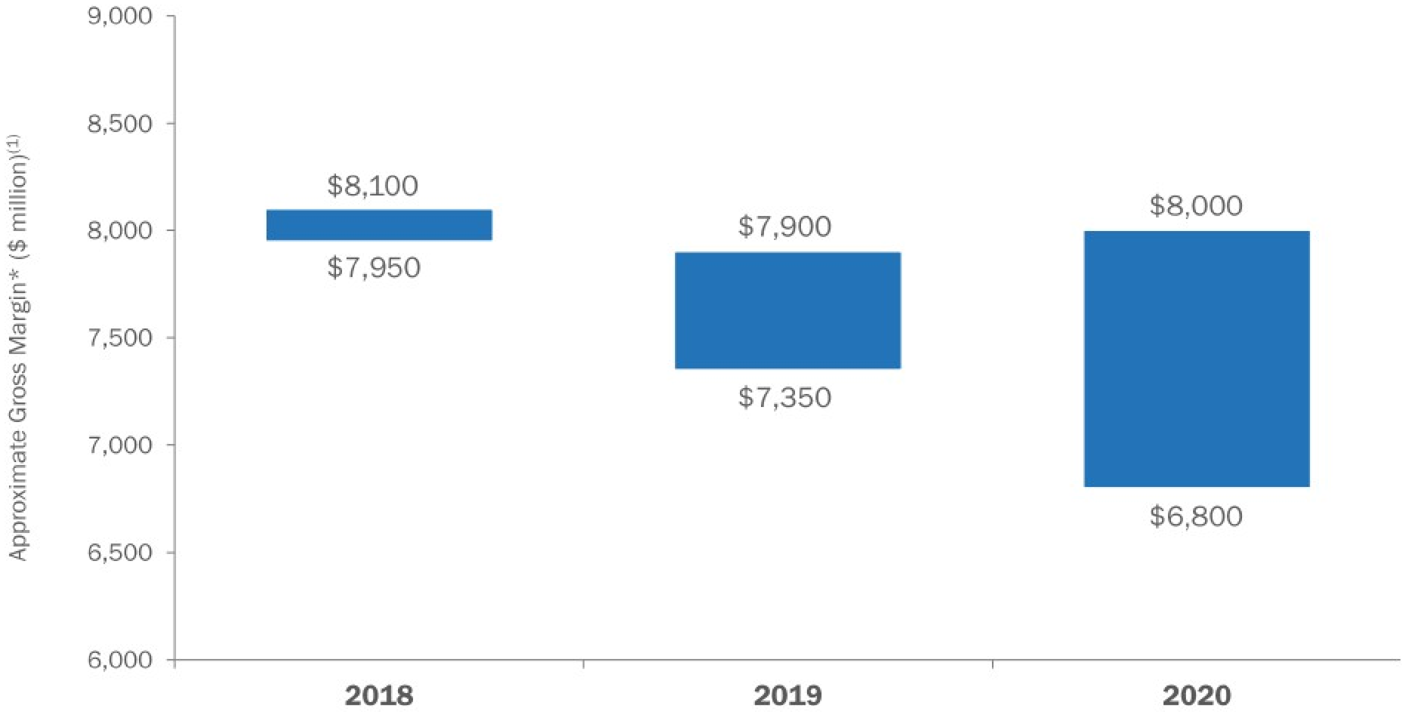
ExGen Hedged Gross Margin* Upside/Risk



(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 2019 and 2020 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, 2018. Gross Margin Upside/Risk based on commodity exposure which includes open generation and all committed transactions. Reflects Oyster Creek and TMI retirements by October 2018 and September 2019, respectively. 2018, 2019 and 2020 are adjusted for retaining Handley Generating Station.

Illustrative Example of Modeling Exelon Generation 2019 Total Gross Margin*

Row	Item	Midwest	Mid-Atlantic	ERCOT	New York	New England	South, West & Canada
(A)	Start with fleet-wide open gross margin	←		$4.05 billion			→
(B)	Capacity and ZEC	←		$2.05 billion			→
(C)	Expected Generation (TWh)	97.1	54.1	25.9	16.6	8.7	
(D)	Hedge % (assuming mid-point of range)	69.5%	82.5%	75.5%	76.5%	34.5%	
(E=C*D)	Hedged Volume (TWh)	67.5	44.6	19.6	12.7	3.0	
(F)	Effective Realized Energy Price ($/MWh)	$29.00	$38.00	$3.50	$33.00	$1.50	
(G)	Reference Price ($/MWh)	$26.04	$31.38	$9.70	$28.21	$5.12	
(H=F-G)	Difference ($/MWh)	$2.96	$6.62	($6.20)	$4.79	($3.62)	
(I=E*H)	Mark-to-Market value of hedges ($ million)[1]	$200	$295	($120)	$60	($10)	
(J=A+B+I)	Hedged Gross Margin ($ million)			$6,500			
(K)	Power New Business / To Go ($ million)			$600			
(L)	Non-Power Margins Executed ($ million)			$150			
(M)	Non-Power New Business / To Go ($ million)			$350			
(N=J+K+L+M)	**Total Gross Margin***			**$7,600 million**			

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

Additional ExGen Modeling Data

Total Gross Margin Reconciliation (in $M)[1]	2018	2019	2020
Revenue Net of Purchased Power and Fuel Expense*[2,3]	**$8,500**	**$8,075**	**$7,750**
Other Revenues[4]	$(200)	$(175)	$(200)
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses	$(250)	$(300)	$(250)
Total Gross Margin* (Non-GAAP)	**$8,050**	**$7,600**	**$7,300**

Key ExGen Modeling Inputs (in $M)[1,5]	2018
Other[6]	$250
Adjusted O&M*	$(4,625)
Taxes Other Than Income (TOTI)[7]	$(375)
Depreciation & Amortization*[8]	$(1,125)
Interest Expense	$(400)
Effective Tax Rate	**22.0%**

(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 reflects primarily revenues from JExel Nuclear JV, variable interest entities, funds collected through revenues for decommissioning the former PECO nuclear plants through regulated rates, and gross receipts tax revenues
(5) ExGen amounts for O&M, TOTI, Depreciation & Amortization; excludes EDF's equity ownership share of the CENG Joint Venture
(6) Other reflects Other Revenues excluding gross receipts tax revenues, includes nuclear decommissioning trust fund earnings from unregulated sites, and includes the minority interest in ExGen Renewables JV and Bloom. Other for 2018 is favorable due to NDTF realized gains that may not occur in 2019 and 2020.
(7) TOTI excludes gross receipts tax of $150M
(8) 2019 Depreciation & Amortization is flat to 2018 and 2020 is favorable $50M due to nuclear plant retirements

Appendix

Reconciliation of Non-GAAP Measures

Q2 QTD GAAP EPS Reconciliation

Three Months Ended June 30, 2017	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
2017 GAAP (Loss) Earnings Per Share(1)	**($0.25)**	**$0.13**	**$0.09**	**$0.05**	**$0.07**	**$0.02**	**$0.10**
Mark-to-market impact of economic hedging activities	0.12	-	-	-	-	-	0.12
Unrealized gains related to NDT fund investments	(0.05)	-	-	-	-	-	(0.05)
Amortization of commodity contract intangibles	0.01	-	-	-	-	-	0.01
Merger and integration costs	0.01	-	-	-	-	-	0.02
Long-lived asset impairments	0.29	-	-	-	-	-	0.29
Plant retirements and divestitures	0.07	-	-	-	-	-	0.07
Cost management program	-	-	-	-	-	-	0.01
Like-kind exchange tax position	-	0.02	-	-	-	(0.05)	(0.03)
Noncontrolling interest	0.02	-	-	-	-	-	0.02
2017 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	**$0.23**	**$0.15**	**$0.10**	**$0.05**	**$0.07**	**$(0.03)**	**$0.56**

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

(1) Certain immaterial prior year amounts in the Registrants' Consolidated Statements of Operations and Comprehensive Income have been recast to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018

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Q2 QTD GAAP EPS Reconciliation (continued)

Three Months Ended June 30, 2018	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
2018 GAAP Earnings (Loss) Per Share	**$0.18**	**$0.17**	**$0.10**	**$0.05**	**$0.09**	**($0.04)**	**$0.56**
Mark-to-market impact of economic hedging activities	(0.07)	-	-	-	-	-	(0.07)
Unrealized losses related to NDT fund investments	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	**$0.34**	**$0.17**	**$0.10**	**$0.05**	**$0.09**	**($0.05)**	**$0.71**

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

Q2 YTD GAAP EPS Reconciliation

Six Months Ended June 30, 2017	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
2017 GAAP Earnings Per Share[1]	**$0.20**	**$0.28**	**$0.23**	**$0.18**	**$0.22**	**$0.06**	**$1.17**
Mark-to-market impact of economic hedging activities	0.15	-	-	-	-	-	0.15
Unrealized gains related to NDT fund investments	(0.15)	-	-	-	-	-	(0.15)
Amortization of commodity contract intangibles	0.02	-	-	-	-	-	0.02
Merger and integration costs	0.04	-	-	-	-	-	0.04
Merger commitments	(0.02)	-	-	-	(0.06)	(0.06)	(0.15)
Long-lived asset impairments	0.29	-	-	-	-	-	0.29
Plant retirements and divestitures	0.07	-	-	-	-	-	0.07
Cost management program	0.01	-	-	-	-	-	0.01
Bargain purchase gain	(0.24)	-	-	-	-	-	(0.24)
Like-kind exchange tax position	-	0.02	-	-	-	(0.05)	(0.03)
Reassessment of deferred income taxes	-	-	-	-	-	(0.02)	(0.02)
Tax settlements	(0.01)	-	-	-	-	-	(0.01)
Noncontrolling interest	0.06	-	-	-	-	-	0.06
2017 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	**$0.41**	**$0.30**	**$0.23**	**$0.18**	**$0.15**	**($0.08)**	**$1.21**

Note: All amounts shown are per Exelon share and represent contributions to Exelon's EPS. Amounts may not add due to rounding.
(1) Certain immaterial prior year amounts in the Registrants' Consolidated Statements of Operations and Comprehensive Income have been recast to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018

Q2 YTD GAAP EPS Reconciliation (continued)

Six Months Ended June 30, 2018	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
2018 GAAP Earnings (Loss) Per Share	**$0.32**	**$0.34**	**$0.22**	**$0.18**	**$0.15**	**($0.06)**	**$1.16**
Mark-to-market impact of economic hedging activities	0.13	-	-	-	-	-	0.13
Unrealized losses related to NDT fund investments	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	**$0.83**	**$0.34**	**$0.22**	**$0.19**	**$0.16**	**($0.07)**	**$1.66**

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

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Projected GAAP to Operating Adjustments

- **Exelon's projected 2018 adjusted (non-GAAP) operating earnings excludes the earnings effects of the following:**
  - Mark-to-market adjustments from economic hedging activities
  - Unrealized gains and losses from NDT fund investments
  - Certain merger and integration costs
  - Impairments of certain wind projects at Generation
  - Certain costs related to plant retirements
  - Costs incurred related to a cost management program
  - Generation's noncontrolling interest, primarily related to CENG exclusion items
  - One-time impacts of adopting new accounting standards
  - Other unusual items

GAAP to Non-GAAP Reconciliations[1]

Exelon FFO/Debt[2] = **FFO (a)** / **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 = $\frac{\text{Net Debt (a)}}{\text{Operating EBITDA (b)}}$

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

Q2 2018 Operating ROE Reconciliation ($M)	ACE	Delmarva	Pepco	Legacy EXC	Consolidated EU
Net Income (GAAP)	$57	$102	$189	$1,384	$1,731
Operating Exclusions	$0	$8	$3	$2	$13
Adjusted Operating Earnings	$57	$109	$192	$1,386	$1,744
Average Equity	$1,044	$1,425	$2,577	$13,439	$18,485
Operating ROE (Adjusted Operating Earnings/Average Equity)	**5.4%**	**7.7%**	**7.4%**	**10.3%**	**9.4%**

Q1 2018 Operating ROE Reconciliation ($M)	ACE	Delmarva	Pepco	Legacy EXC	Consolidated EU
Net Income (GAAP)	$56	$94	$178	$1,321	$1,650
Operating Exclusions	$0	$7	($1)	$26	$32
Adjusted Operating Earnings	$56	$101	$177	$1,347	$1,682
Average Equity	$1,046	$1,341	$2,433	$13,164	$17,985
Operating ROE (Adjusted Operating Earnings/Average Equity)	**5.4%**	**7.6%**	**7.3%**	**10.2%**	**9.4%**

ExGen Adjusted O&M Reconciliation ($M)(1)	2018
GAAP O&M	**$5,375**
Decommissioning(2)	50
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses(3)	(275)
O&M for managed plants that are partially owned	(400)
Other	(125)
Adjusted O&M (Non-GAAP)	**$4,625**

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

GAAP to Non-GAAP Reconciliations

2018 Adjusted Cash from Ops Calculation ($M)[1]	BGE	ComEd	PECO	PHI	ExGen	Other	Exelon
Net cash flows provided by operating activities (GAAP)	$700	$1,475	$625	$1,100	$4,250	$175	$8,325
Other cash from investing activities	-	-	-	-	($275)	-	($275)
Counterparty collateral activity	-	-	-	-	-	-	-
Adjusted Cash Flow from Operations	**$700**	**$1,475**	**$625**	**$1,100**	**$3,975**	**$175**	**$8,050**

2018 Cash From Financing Calculation ($M)[1]	BGE	ComEd	PECO	PHI	ExGen	Other	Exelon
Net cash flow provided by financing activities (GAAP)	$325	$900	($0)	$450	($1,075)	($125)	$475
Dividends paid on common stock	$200	$450	$300	$300	$1,000	($950)	$1,325
Financing Cash Flow	**$525**	**$1,375**	**$300**	**$750**	**($75)**	**($1,050)**	**$1,800**

Exelon Total Cash Flow Reconciliation[1]	2018
GAAP Beginning Cash Balance	**$900**
Adjustment for Cash Collateral Posted	$550
Adjusted Beginning Cash Balance[3]	$1,450
Net Change in Cash (GAAP)[2]	$600
Adjusted Ending Cash Balance[3]	$2,050
Adjustment for Cash Collateral Posted	($550)
GAAP Ending Cash Balance	**$1,525**

(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

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Exelon Corporation Quarter Review

Exelon

Q2 2018

GAAP Earnings $0.56 per share

Adjusted earnings of $0.71 per share*

We have met or beaten[1] the mid-point of our earnings guidance for **12 of the past 14 quarters**

New Jersey

zero emissions certificate (ZEC) legislation signed by Governor Murphy in May

over $675 million

Projected savings for electric & gas customers from Tax Cuts & Jobs Act

Utilities

- Legislation passed in Pennsylvania and Delaware to support investments in Utility of the Future
- Top decile performance across all utilities for CAIDI (outage management)
- Customer service metrics continue to be strong across all utilities
- Second consecutive electric rate case settlement for Delmarva Power in Delaware

CORPORATE STEWARDSHIP

Volunteer Month

5,233

employees volunteered **18,206 hours** in **104 cities**

Diversity

DiversityInc

Named Top 50 Company for Diversity and Top 5 company for Veterans by DiversityInc.

Exelon

Named Corporation of the Year by Chicago Minority Supplier Development Council Inc.

Exelon Generation

Continued **best-in-class performance** across our Nuclear fleet:

93.2%

Q2 Nuclear Capacity Factor[2]

39.3 TWhs

Owned and operated Q2 production[2]

* For reconciliation of GAAP Net Income to Adjusted (non-GAAP) Operating Earnings, refer to the tables in our press release

(1) Non-GAAP Earnings are used for setting guidance and comparing to actual results

(2) Excludes Salem