Novocure Ltd
Form DEF 14A
April 20, 2018

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

SCHEDULE 14A

Proxy Statement Pursuant to Section 14(a) of the

Securities Exchange Act of 1934

(Amendment No.)

Filed by the Registrant Filed by a Party other than the Registrant

Check the appropriate box:

Preliminary Proxy Statement
Confidential, for Use of the Commission Only (as permitted by Rule 14a-6(e)(2))
Definitive Proxy Statement
Definitive Additional Materials
Soliciting Material under § 240.14a-12

NovoCure Limited

(Name of Registrant as Specified In Its Charter)

(Name of Person(s) Filing Proxy Statement, if other than the Registrant)

Payment of Filing Fee (Check the appropriate box):

No fee required.

Fee computed on table below per Exchange Act Rules 14a-6(i)(1) and 0-11.

(1) Title of each class of securities to which transaction applies:

(2) Aggregate number of securities to which transaction applies:

(3) Per unit price or other underlying value of transaction computed pursuant to Exchange Act Rule 0-11 (set forth the amount on which the filing fee is calculated and state how it was determined):

(4) Proposed maximum aggregate value of transaction:

(5) Total fee paid:

Fee paid previously with preliminary materials.

Check box if any part of the fee is offset as provided by Exchange Act Rule 0-11(a)(2) and identify the filing for which the offsetting fee was paid previously. Identify the previous filing by registration statement number, or the Form or Schedule and the date of its filing.

(1) Amount Previously Paid:

(2) Form, Schedule or Registration Statement No.:

(3) Filing Party:

(4) Date Filed:

2018 Proxy Statement

To the shareholders of NovoCure Limited:

NOTICE IS HEREBY GIVEN that the Annual General Meeting of Shareholders (“Annual Meeting”) of NovoCure Limited, a Jersey (Channel Islands) corporation (referred to herein as the “Company”, “Novocure”, “we”, “us” or “our”), will b held on May 31, 2018, at 9:00 a.m. U.S. Eastern Standard Time (EST), at Second Floor, No. 4 The Forum, Grenville Street, St. Helier, Jersey, Channel Islands JE2 4UF, for the following purposes:

1. To elect six directors named in the Proxy Statement, two of whom will be designated as Class II directors, to hold office until the 2020 annual general meeting of shareholders and four of whom will be designated as Class III directors, to hold office until the 2021 annual general meeting of shareholders or until their successors are duly elected and qualified or until their offices are vacated;
2. The approval and ratification of the appointment, by the Audit Committee of our Board of Directors (the “Board”), of Kost Forer Gabbay & Kasierer, a member of Ernst & Young Global (“EY Global”), as the auditor and independent registered public accounting firm of the Company for the Company’s fiscal year ending December 31, 2018;
3. A non-binding advisory vote to approve executive compensation;
4. A non-binding advisory vote to approve the frequency of the advisory vote on executive compensation; and
5. The approval of an amendment to our Articles of Association (the “Articles”) to remove the classified structure of our Board, provide for the annual election of directors and allow our Board to appoint new directors between annual meetings.

The foregoing items of business, four of which will be proposed as ordinary resolutions (Proposals 1-4) and one of which will be proposed as a special resolution within the meaning of our Articles (Proposal 5), are more fully described in the Proxy Statement. Only shareholders who owned our ordinary shares at the close of business on March 27, 2018 (the “Record Date”) can vote at this meeting or at any adjournments that take place or postponements thereof.

A shareholder entitled to attend and vote at the Annual Meeting is entitled to appoint one or more proxies to attend and vote in the place of such shareholder and such proxy or proxies need not also be a shareholder of the Company. We have elected to use the Internet as our primary means of providing our proxy materials to shareholders. Consequently, shareholders will not receive paper copies of our proxy materials, unless they specifically request them. We will send a notice regarding the Internet availability of proxy materials (the “Notice of Internet Availability”) on or about April 20, 2018 to our shareholders of record as of the close of business on the Record Date. The Notice of

Internet Availability contains instructions for accessing the proxy materials on the Internet, including the Proxy Statement and our Annual Report on Form 10-K for the fiscal year ended December 31, 2017 (the “Annual Report”), and provides information on how shareholders may obtain paper copies free of charge. The Notice of Internet Availability also provides the date, time and location of the Annual Meeting; the matters to be acted upon at the meeting and the recommendation from our Board with regard to each matter; and information on how to attend the meeting. Electronic delivery of our proxy materials will significantly reduce our printing and mailing costs and the environmental impact of mailing these materials.

It is important that your shares be represented and voted whether or not you plan to attend the Annual Meeting in person. Other than voting in person at the Annual Meeting, you may vote over the Internet, by telephone or by completing and mailing a proxy card or voting instruction card forwarded by your bank, broker or other holder of record. Voting over the Internet, by telephone or by written proxy will ensure your shares are represented at the Annual Meeting. Please review the instructions on the proxy card or voting instruction card forwarded by your bank, broker or other holder of record regarding each of these voting options.

Our Board of Directors recommends that you vote FOR the election of the two Class II and four Class III director nominees named in Proposal 1 of the Proxy Statement, FOR the approval and ratification of the appointment of EY Global as our auditor and independent registered public accounting firm for the Company's fiscal year ending December 31, 2018, FOR the non-binding advisory vote to approve executive compensation, every ONE YEAR as the frequency of the advisory vote to approve executive compensation, and FOR the amendment of our Articles to remove the classified structure of our Board, provide for the annual election of directors and allow our Board to appoint new directors between annual meetings.

By Order of the Board of Directors
William F. Doyle

Chairman of the Board of Directors

St. Helier, Jersey, Channel Islands

April 20, 2018

IMPORTANT NOTICE REGARDING THE AVAILABILITY OF PROXY MATERIALS FOR THE

ANNUAL GENERAL MEETING OF SHAREHOLDERS TO BE HELD ON MAY 31, 2018

The Proxy Statement, Notice of Annual General Meeting of Shareholders

and Annual Report are available at www.proxyvote.com.

2

2018 Proxy Statement

TABLE OF CONTENTS

QUESTIONS AND ANSWERS ABOUT THE ANNUAL MEETING	11
PROPOSAL 1—Election of Four Class II Directors	16
Class II Nominees for Election to a Two-Year Term Expiring at the 2020 Annual General Meeting of Shareholders	17
Class III Nominees for Election to a Three-Year Term Expiring at the 2021 Annual General Meeting of Shareholders	18
Class I Directors Continuing in Office until the 2019 Annual General Meeting of Shareholders	20
PROPOSAL 2—Ratification of Approval and Appointment of Independent Registered Public Accounting Firm	23
Principal Accountant Fees and Services	23
Pre-Approval Policies and Procedures	23
PROPOSAL 3—Non-Binding Advisory Vote on the Approval of Executive Compensation	24
PROPOSAL 4—Non-Binding Advisory Vote to Approve the Frequency of the Advisory Vote on Executive Compensation	25
PROPOSAL 5—Approval of the Amendment of the Articles to Remove the Classified Structure of Our Board and Provide for the Annual Election of Directors and to Allow Appointment of New Directors Between Annual Meetings	26

REPORT OF THE AUDIT COMMITTEE OF THE BOARD OF DIRECTORS		28
CORPORATE GOVERNANCE		29
	Independence of the Board of Directors	29
	Board Leadership Structure	29
	Role of Board in Risk Oversight Process	30
	Board Committees	31
	Meetings of the Board of Directors, Board and Committee Member Attendance, and Annual Meeting Attendance	34
	Director Nomination Process	34
	Code of Ethics	35
	Corporate Governance Guidelines	36
	Shareholder Communications with the Board of Directors	36
	Compensation Committee Interlocks and Insider Participation	36
CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS		37
	Related party transaction policy	37
DIRECTOR COMPENSATION		38
	Current Compensation Structure	38
	Compensation	39
EXECUTIVE COMPENSATION		41
	Compensation Policies and	51

Practices	
Summary Compensation Table	53
Outstanding Equity Awards at 2017 Fiscal Year End	57
Potential Payment upon Termination or Change in Control	58

	Equity Compensation Plan Information	65
SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT		66
SECTION 16(A) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE		69
ADDITIONAL INFORMATION		69
	Householding of Proxy Materials	69
	Presentation of Accounts	69
	Shareholder Proposals and Nominations for the 2018 Annual General Meeting of Shareholders	69
	Other Matters	70
	Annual Reports	70
	Appendix A	71

PROXY STATEMENT SUMMARY

This Proxy Statement Summary contains highlights of certain information in this Proxy Statement. This Summary does not contain all the information that you should consider prior to voting. Please review the complete Proxy Statement and the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2017 (the "Annual Report") that accompanies the Proxy Statement for additional information.

2018 ANNUAL MEETING OF SHAREHOLDERS

Date and Time:	Thursday, May 31, 2018, at 9:00 a.m. U.S. Eastern Standard Time ("EST")
Place:	Second Floor, No. 4 The Forum, Grenville Street, St. Helier, Jersey, Channel Islands JE2 4UF
Record Date:	March 27, 2018
Voting Deadline:	Votes submitted by Internet, telephone or mail must be received by 11:59 p.m. EST on May 28, 2018 to be counted. Shareholders may also vote in person at the Annual Meeting.

VOTING MATTERS AND BOARD RECOMMENDATIONS

Voting Matter	Board Recommendation	Page Number with More Information
Election of the two Class II and four Class III director nominees	FOR all nominees	16
Approval and ratification of the appointment of EY Global as our auditor and independent registered public accounting firm for the Company's fiscal year ending December 31, 2018	FOR	23
Non-binding advisory vote to approve executive compensation	FOR	24
	ONE YEAR	25

Non-binding advisory vote to approve the frequency of the advisory vote on executive compensation		
Approval of the amendment of our Articles of Association (the "Articles") to remove the classified structure of our Board of Directors (the "Board"), provide for the annual election of directors and allow our Board to appoint new directors between annual meetings	FOR	26

DIRECTOR NOMINEES

You have the opportunity to vote on the election of the following nominees for director. Additional information regarding each director nominee's experience, skills and qualifications to serve as a member of the Board can be found in the Proxy Statement under Proposal No. 1 – Election of Directors.

Name	Age	Years on Board	Occupation	Independent	Committees
Asaf Danziger	51	6	Chief Executive Officer, Novocure	No	None
William F. Doyle	55	14	Executive Chairman, Novocure	No	None
David T. Hung	60	—	Former Chief Executive Officer of Axovant Sciences, Inc. and Medivation, Inc.	Yes	N/A
Sherilyn D. McCoy	59	—	Former Chief Executive Officer of Avon Products, Inc.	Yes	N/A
Charles G. Phillips, III	69	6	Former Chief Operating Officer of Prentice Capital Management, LLC	Yes	Audit and Compensation
William A. Vernon	62	12	Former Chief Executive Officer of Kraft Foods Group, Inc.	Yes	Compensation and Nominating and Corporate Governance

BOARD AND DIRECTOR NOMINEE HIGHLIGHTS

- 6 director nominees; 4 are independent
- Average age of director nominees is 59
- Average tenure of director nominees, excluding first-time nominees, is 9 years
- 2 new director nominees in 2018
- One director nominee is female
    - Highly qualified directors reflect broad mix of business backgrounds, skills and experiences

CORPORATE GOVERNANCE HIGHLIGHTS

- Separate Executive Chairman of the Board and Chief Executive Officer positions
- Strong Lead Independent Director position
- 3 fully independent Board committees
- Executive session of independent directors held at each regularly-scheduled Board meeting
- Frequent Board and committee meetings to ensure awareness and alignment
- 6 Board meetings in 2017
- 16 standing committee meetings in 2017
- 2 special committee meetings in 2017
    - On average, directors attended 95% of Board and committee meetings held in 2017
- Annual Board and committee self-assessments and discussions with individual directors
- Strong clawback and anti-hedging/anti-pledging policies
- Senior executives do not receive tax gross-ups on severance or change in control benefits
- Significant share ownership requirements for directors and senior executives
- Our Board and its committees have an active role in risk oversight

2017 CORPORATE ACHIEVEMENTS

- Active patient growth of 68% year over year, with 1,834 active patients on Optune at December 31, 2017;
- Delivery of $177.0 million in net revenues, driven by increased Optune adoption and by an increase in net revenues per patient;
- Publication of the full 695 patient data from our phase 3 pivotal EF-14 trial in newly diagnosed GBM in the Journal of the American Medical Association (JAMA);
- Opening two additional phase 3 pivotal clinical trials in pancreatic cancer and non-small cell lung cancer;
- Receipt of a humanitarian use device designation for the use of Tumor Treating Fields for the treatment of pleural mesothelioma;
- Obtaining national reimbursement decisions for Optune in Japan and Austria;
- Securing positive coverage of Optune for more than 96% of Americans with private health insurance;
- An increase in our closing share price from $7.85 on December 30, 2016 to $20.20 on December 29, 2017, the last trading day of each year; and
- 114% year-over-year revenue growth with only 11% year-over-year increase in SG&A expenses, reflecting management's ongoing commitment to driving operating leverage.

GENERAL INFORMATION

Stock Symbol	NVCR
Exchange	NASDAQ
Ordinary Shares Outstanding on the Record Date	90,398,901
Registrar and Transfer Agent	Computershare Shareowner Services LLC
Principal Office	Second Floor, No. 4 The Forum, Grenville Street St. Helier, Jersey, Channel Islands JE2 4UF
Corporate Website	www.novocure.com

EXECUTIVE COMPENSATION HIGHLIGHTS

The primary objectives of our executive compensation program are to attract, retain and motivate superior executive talent, to provide incentives that reward the achievement of performance goals that we believe support the enhancement of shareholder value and to align the executives' interests with those of shareholders through long-term incentives. To achieve these objectives, our executive compensation program includes the following key features:

We Pay for Performance by delivering incentive compensation as a significant portion of total compensation so that our executives are properly motivated to achieve or exceed our key objectives.

- Payouts under our annual cash incentive program for 2017 were 100% performance based.
- Annual equity grants are delivered via a blend of share options and time-based restricted share units.
- Equity awards granted to our Executive Chairman include performance-based share options, which will be earned based on achievement of pre-determined share price performance goals.
- Share options granted to our executives will only have value to the extent our share price increases over the long term.

We Pay Competitively by targeting total cash compensation and total direct compensation for each of our executives based on a review of market data for our defined market for talent.

- We regularly review and, as appropriate, make changes to our peer group to ensure it is representative of our market for talent, our business portfolio, our overall size and our global footprint.
- In addition to review of market data, we also consider the Company's and the executive's performance, internal comparisons, potential, scope of position, retention needs, dilution constraints and other factors deemed appropriate.
- Given the location of our executives in both Israel and the United States, we benchmark not only against our peers but also in consideration of customary executive compensation practices in Israel and the United States.
- We provide perquisites and benefits that we believe are competitive and customary, but not excessive.

We Align Our Compensation Program with Shareholder Interests by providing a significant portion of each executive's compensation opportunity in the form of equity and requiring executive share ownership.

- Following the rise in the Company's share price in 2017, all of our executives have meaningful equity value in their equity holdings, maintaining the retention value of the program.
- Share ownership requirements for our executives range from 5x salary (for our CEO and Executive Chairman) to 3x salary (for other executives).

The Board of Directors (“Board”) of NovoCure Limited (referred to herein as the “Company”, “Novocure”, “we”, “us” or “our soliciting your proxy to vote at our 2018 Annual General Meeting of Shareholders to be held on Thursday, May 31, 2018, at 9:00 a.m. U.S. Eastern Standard Time (“EST”), at Second Floor, No. 4 The Forum, Grenville Street, St. Helier, Jersey, Channel Islands JE2 4UF, and any adjournment or postponement of that meeting (the “Annual Meeting”).

We have elected to provide access to our proxy materials on the Internet. Accordingly, we are sending a notice regarding the Internet availability of proxy materials (the “Notice of Internet Availability”) to holders of record of our ordinary shares (“Ordinary Shares”) as of March 27, 2018 (the “Record Date”). All shareholders will have the ability to access the proxy materials on the website referred to in the Notice of Internet Availability, or to request a printed set of the proxy materials. Instructions on how to request a printed copy by mail or e-mail may be found in the Notice of Internet Availability and on the website referred to in the Notice of Internet Availability, including instructions on how to request paper copies on an ongoing basis. On or about April 20, 2018, we are making this Proxy Statement available on the Internet and are mailing the Notice of Internet Availability to all shareholders entitled to vote at the Annual Meeting.

The Company’s Annual Report on Form 10-K, which contains financial statements for the fiscal year ended December 31, 2017 (“Annual Report”), accompanies this Proxy Statement if you have requested and received a copy of the proxy materials in the mail. Shareholders that receive the Notice of Internet Availability can access this Proxy Statement and the Annual Report at the website referred to in the Notice of Internet Availability. The Annual Report and this Proxy Statement are also available on our investor relations website at www.novocure.com and at the website of the Securities and Exchange Commission (the “SEC”) at www.sec.gov. You also may obtain a copy of the Annual Report, without charge, by writing to our Investor Relations department, NovoCure Limited, at 20 Valley Stream Parkway, Suite 300, Malvern, Pennsylvania 19355.

THE PROXY PROCESS AND SHAREHOLDER VOTING

QUESTIONS AND ANSWERS ABOUT THE ANNUAL MEETING

Who can vote at the Annual Meeting?

Only shareholders of record at the close of business on March 27, 2018 will be entitled to vote at the Annual Meeting. At the close of business on the Record Date, there were 90,398,901 Ordinary Shares issued and outstanding and entitled to vote. On each matter to be voted upon, you have one vote for each Ordinary Share you own as of the Record Date.

What am I being asked to vote on?

You are being asked to vote on five proposals:

- Proposal 1: To elect the six directors named in this Proxy Statement, two of whom will be designated as Class II directors and four of whom will be designated as Class III directors, to hold office until the 2020 and 2021 annual general meeting of shareholders, respectively, or until their successors are duly elected and qualified or until their offices are vacated;
- Proposal 2: To approve and ratify the appointment, by the Audit Committee of our Board, of Kost Forer Gabbay & Kasierer, a member of Ernst & Young Global ("EY Global"), as our auditor and independent registered public accounting firm for the fiscal year ending December 31, 2018;
- Proposal 3: To hold a non-binding advisory vote to approve our executive compensation;
- Proposal 4: To hold a non-binding advisory vote to approve the frequency of the advisory vote on executive compensation; and
- Proposal 5: To approve the amendment of our Articles to remove the classified structure of our Board, provide for the annual election of directors and allow our Board to appoint new directors between annual meetings.

In addition, you are entitled to vote on any other matters that are properly brought before the Annual Meeting.

How do I vote?

The procedures for voting, depending on whether you are a shareholder of record or a beneficial owner holding in "street name," are as follows:

Shareholder of Record—Shares Registered in Your Name

If you are a shareholder of record, you may vote in any of the following manners:

- To vote in person, come to the Annual Meeting and we will give you a ballot when you arrive.
- To vote over the Internet prior to the Annual Meeting, follow the instructions provided on the Notice of Internet Availability or on the proxy card by accessing www.proxyvote.com using the control number contained on the Notice of Internet Availability or proxy card.
-

To vote by telephone, call 1-800-690-6903 (toll free). You will need to have the control number printed on your Notice of Internet Availability or proxy card available when you call.

- To vote by mail, complete, sign and date the proxy card and return it promptly to Vote Processing, c/o Broadridge, 51 Mercedes Way, Edgewood, NY 11717. As long as your signed proxy card is received by May 28, 2018, your shares will be voted as you direct.

Whether or not you plan to attend the Annual Meeting, we urge you to vote by mail, Internet or telephone to ensure your vote is counted. The Internet and telephone voting facilities for eligible shareholders of record will close at 11:59 p.m. EST on May 28, 2018. Proxy cards submitted by mail must be received by 11:59 p.m. U.S. Eastern Time on May 28, 2018 to be counted. Even if you have submitted your vote before the Annual Meeting, you may still attend the Annual Meeting and vote in person. In such case, your previously submitted proxy will be disregarded.

Beneficial Owner—Shares Registered in the Name of Broker, Bank or Other Nominee (“Street Name”)

If you are a beneficial owner of shares registered in the name of your broker, bank or other nominee, you will receive a voting instruction card from that organization. Simply complete and mail the voting instruction card to ensure that your vote is counted or follow such other instructions to submit your vote by the Internet or telephone, if such options are provided by your broker, bank or other nominee. You are also invited to attend the Annual Meeting. However, to vote in person at the Annual Meeting, you must obtain a valid proxy from your broker, bank or other nominee authorizing you to vote at the Annual Meeting. Contact your broker, bank or other nominee to request a proxy form.

How does the Board recommend I vote on the Proposals?

Our Board recommends that you vote:

- FOR the election of each of the two Class II and four Class III director nominees named in this Proxy Statement (Proposal 1);
- FOR the approval and ratification of the appointment of EY Global as our auditor and independent registered public accounting firm for the fiscal year ending December 31, 2018 (Proposal 2);
- FOR the non-binding advisory resolution to approve our executive compensation (Proposal 3);
- ONE YEAR as the frequency of the non-binding advisory vote on executive compensation (Proposal 4); and
- FOR the approval of the amendment of our Articles to remove the classified structure of our Board, provide for the annual election of directors and allow our Board to appoint new directors between annual meetings (Proposal 5).

How many votes are needed to approve each proposal?

With respect to Proposal 1, the election of each of the two Class II and four Class III director nominees, each nominee who receives the affirmative vote of the simple majority of votes cast will be elected. Abstentions and votes by a broker that have not been directed by the beneficial owner to vote (“broker non-votes”) will not be counted for the purposes of determining the number of votes cast and will accordingly will have no effect on the outcome of this proposal.

With respect to Proposal 2, the approval and ratification of the appointment of EY Global as our auditor and independent registered public accounting firm for the fiscal year ending December 31, 2018, the affirmative vote of the simple majority of votes cast is required for approval. Abstentions and broker non-votes will not be counted for the purposes of determining the number of votes cast and will accordingly have no effect on the outcome of this proposal.

With respect to Proposal 3, the non-binding advisory vote on our executive compensation, the affirmative vote of the simple majority of votes cast is required for approval. Abstentions and broker non-votes will not be counted for the purposes of determining the number of votes cast and will accordingly have no effect on the outcome of this proposal.

With respect to Proposal 4, the determination of the frequency of an advisory vote on executive compensation, the affirmative vote of the simple majority of votes cast is required to approve one year, two years, or three years as the shareholders' recommended frequency on this Proposal. However, if none of the options receive the vote of a majority, the option receiving the greatest number of votes will be considered the frequency recommended by our shareholders. Abstentions and broker non-votes will not be counted for the purposes of determining the number of votes cast and will accordingly have no effect on the outcome of this proposal.

With respect to Proposal 5, the approval of the amendment of our Articles to remove the classified structure of our Board, provide for the annual election of directors and allow our Board to appoint new directors between annual meetings, the affirmative vote of a two thirds majority of the votes cast is required for approval, by way of a special resolution. Abstentions and broker non-votes will not be counted for the purposes of determining the number of votes cast and will accordingly have no effect on the outcome of this proposal. Jersey company law requires that a special resolution, such as an amendment to a company's Articles of Association, be approved by the affirmative vote of at least a two thirds majority of the votes cast.

Can I change my vote after submitting my proxy vote?

Yes. You can revoke your proxy vote at any time before the final vote at the Annual Meeting. If you are the record holder of your shares, you may revoke your proxy vote in any one of three ways:

- You may submit a new vote on the Internet or by telephone or submit a properly completed proxy card with a later date.
- You may send a written notice that you are revoking your proxy to our General Counsel, NovoCure Limited, at 20 Valley Stream Parkway, Suite 300, Malvern, Pennsylvania 19355, which must be received by May 28, 2018.
- You may attend the Annual Meeting and vote in person. Simply attending the Annual Meeting will not, by itself, revoke your proxy.

If your shares are held by your broker, bank or other nominee, you should follow the instructions provided by such broker, bank or other nominee to revoke an earlier vote.

Who counts the votes?

Broadridge Financial Solutions, Inc. has been engaged as our independent agent to tabulate shareholder votes, or as our "Inspector of Election."

What are "broker non-votes"?

Broker non-votes occur when a beneficial owner of shares held in "street name" does not give instructions to the broker, bank or other nominee holding the shares as to how to vote on matters deemed "non-routine." If the beneficial owner does not provide voting instructions, the broker or nominee can still vote the shares with respect to matters that are considered to be “routine,” but not with respect to “non-routine” matters.

Proposal 2 is considered "routine" under applicable rules. A broker or other nominee may generally vote on routine matters without voting instructions from beneficial owners, and therefore no broker non-votes are expected to exist in connection with Proposal 2. The remaining proposals are considered "non-routine" under applicable rules. A broker or other nominee cannot vote without instructions on non-routine matters, and therefore there may be broker non-votes on those proposals. Accordingly, if you own shares in street name through a broker, bank or other nominee, please be sure to provide voting instructions to your nominee to ensure that your vote is counted on each of the proposals.

What if I return a Proxy Card but do not make specific choices?

If we receive your signed and dated proxy card and the proxy card does not specify how your shares are to be voted, your shares will be voted "FOR" the election of each of the two nominees for Class II directors and four nominees for Class III directors, "FOR" the approval and ratification of the appointment of EY Global as our auditor and independent registered public accounting firm for the year ending December 31, 2018, "FOR" the non-binding advisory resolution to approve our executive compensation, "ONE YEAR" as the frequency of the non-binding advisory vote on executive compensation and "FOR" the approval of the amendment of our Articles to remove the classified structure of our Board, provide for the annual election of directors and allow our Board to appoint new directors between annual meetings. If any other matter is properly presented at the Annual Meeting, your proxy (one of the individuals named on your proxy card) will vote your shares using his or her best judgment.

Who will solicit proxies on behalf of the Board?

Proxies may be solicited on behalf of the Board by Novocure's directors, officers and regular employees. Additionally, the Board has retained Alliance Advisors, LLC ("Alliance"), a proxy solicitation firm, to solicit proxies on the Board's behalf. We will pay Alliance an estimated fee of $25,000 plus costs and expenses. In addition, Alliance and certain related persons will be indemnified against certain liabilities arising out of or in connection with the engagement.

The original solicitation of proxies by mail may be supplemented by telephone, facsimile, Internet and personal solicitation by Alliance, our directors, officers or other regular employees. Proxies may also be solicited by advertisements in periodicals, press releases issued by us and postings on our corporate website. Unless expressly indicated otherwise, information contained on our corporate website is not part of this proxy statement.

Who is paying for this proxy solicitation?

Novocure will pay for the entire cost of soliciting proxies, including the fees due to Alliance, as discussed above. In addition to the mailed proxy materials, our directors, officers and employees may also solicit proxies in person, by telephone or by other means of communication. Directors, officers and employees will not be paid any additional compensation for soliciting proxies. Brokers, custodians and fiduciaries will be requested to forward proxy soliciting material to the beneficial owners of shares held in their names, and we will reimburse them for their reasonable out-of-pocket expenses incurred in connection with the distribution of proxy materials.

What does it mean if I receive more than one Notice of Internet Availability or more than one set of printed proxy materials?

If you receive more than one Notice of Internet Availability or more than one set of printed proxy materials, your shares are registered in more than one name or are registered in different accounts. In order to vote all of the shares you own, you must follow the instructions for voting on each Notice of Internet Availability or proxy card you receive, as applicable.

How will voting on any business not described in this Proxy Statement be conducted?

We are not aware of any business to be considered at the Annual Meeting other than the items described in this Proxy Statement. If any other matter is properly presented at the Annual Meeting, your proxy will vote your shares using his or her best judgment.

What is the quorum requirement?

A quorum of shareholders is necessary to hold a valid meeting. A quorum will be present if the holders of a majority of Ordinary Shares issued and outstanding and entitled to vote on the business being transacted are present in person or represented by proxy at the time when the Annual Meeting proceeds to business.

If you are a shareholder of record, your shares will be counted towards the quorum only if you submit a valid proxy or vote in person at the Annual Meeting. If you are a beneficial owner of shares held in "street name," your shares will be counted towards the quorum if your broker or nominee submits a proxy for your shares at the Annual Meeting. Abstentions and broker non-votes will be counted towards the quorum requirement. If within half an hour from the time appointed for the Annual Meeting there is no quorum or if during the Annual Meeting a quorum ceases to be present, the Annual Meeting shall stand adjourned to the same day in the next week at the same time and place or to such other time and place as the directors shall determine.

How can I find out the results of the voting at the Annual Meeting?

Voting results will be announced by the filing of a Current Report on Form 8-K with the U.S. Securities and Exchange Commission ("SEC") within four business days after the Annual Meeting.

PROPOSAL 1

ELECTION OF DIRECTORS

Our Articles provide that our Board may consist of between two (2) and thirteen (13) directors, as determined by our Board from time to time. Our Board currently has ten (10) members and has approved an increased in the size of the Board to eleven (11) members contingent upon the election of all director nominees at the Annual Meeting. Our Board is divided into three classes, designated as Class I, Class II and Class III, with members of each class serving staggered terms. The current members of the classes are divided as follows:

- the Class I directors are William Burkoth, Kinyip Gabriel Leung and Yoram Palti;
- the Class II directors are Louis J. Lavigne, Jr., Martin J. Madden and Gert Lennart Perlhagen; and
- the Class III directors are Asaf Danziger, William F. Doyle, Charles G. Phillips III and William A. Vernon.

Mr. Perlhagen, a current Class II director, has tendered his resignation effective as of the date of the Annual Meeting. Mr. Perlhagen has been a valued member of our Board since 2003 and we thank him for his service to the Company. The Board has nominated Sherilyn McCoy and David Hung to stand for election as Class II directors at the Annual Meeting.

Class III directors were originally elected to serve on our Board pursuant to an investors rights agreement, which was terminated upon the completion of our initial public offering ("IPO") on October 2, 2015.

Upon the expiration of the term of a class of directors, directors in that class are eligible to be elected for a three-year term at the annual general meeting of shareholders in the year in which their term expires or until their successor is elected and has been qualified, or until such director's earlier death, resignation or removal as provided for in our Articles. If a vacancy arises on our Board during the term of a director's appointment as a result of death, resignation or removal, then a majority of our directors then in office (acting upon the recommendation of our independent directors or a committee thereof) shall have the power at any time and from time to time to appoint any person to be a director as a replacement to fill the vacancy and such person will serve for the remainder of the term of the director he or she has replaced.

Each person nominated for election has agreed to serve if elected, and management has no reason to believe that any nominee will be unable to serve. In the event that any nominee should be unavailable for election as a result of an unexpected occurrence, such shares will be voted for the election of such substitute nominee as our Board may propose.

Proposed Declassification of Board

As explained in further detail in Proposal 5, the Board has approved, and is recommending our shareholders adopt, proposed amendments to our Articles of Association to declassify the Board and provide for the annual election of directors. If Proposal 5 is approved by our shareholders at the Annual Meeting, then beginning with the annual meeting of shareholders to be held in 2019, director nominees will, if elected, serve for one-year terms. However, the approval or disapproval of Proposal 5 by our shareholders will not affect the length of the term that our current director nominees will, if elected at the Annual Meeting, serve or the length of the existing terms of our other current directors. Pursuant to this staggered approach to declassifying the Board, the first year in which all of our directors would be elected for a one-year term would be the annual meeting of shareholders in 2021.

Our current Class III directors will continue to serve as Class III directors, if elected, following the Annual Meeting. Sherilyn McCoy and David Hung are new nominees who, if elected, will serve as Class II directors following the Annual Meeting.

The following table sets forth, for our two Class II and four Class III director nominees and for our continuing directors, information with respect to their independence, length of service on our Board and their ages:

Name	Age	Independent	Director Since
Class I Directors whose terms expire at the 2019 Annual Meeting of Shareholders			
William Burkoth	41	Yes	2009
Kinyip Gabriel Leung	56	No	2011
Yoram Palti	80	No	2002
Class II Directors whose terms expire at the 2020 Annual Meeting of Shareholders			
Louis J. Lavigne, Jr.	69	Yes	2012
Martin J. Madden	57	Yes	2017
Gert Lennart Perlhagen	75	Yes	2003
New Class II Director Candidates			
David T. Hung	60	Yes	—
Sherilyn D. McCoy	59	Yes	—
Class III Directors whose terms expire at the 2018 Annual Meeting of Shareholders			
Asaf Danziger	51	No	2012
William F. Doyle	55	No	2004
Charles G. Phillips, III	69	Yes	2012
William A. Vernon	62	Yes	2006

Class II Nominees for Election to a Two-Year Term Expiring at the 2020 Annual General Meeting of Shareholders

David T. Hung

Experience: Dr. Hung was chief executive officer and a director of Axovant Sciences, Inc., a pharmaceutical company, from April 2017 to February 2018, and he was president, chief executive officer of Medivation, Inc., a biopharmaceutical company, from 2004 to 2016. Previously, Dr. Hung served as the president and chief executive officer, and member of the board of directors, of Medivation Neurology, Inc. from its inception in 2003 through 2004, when it became a wholly owned subsidiary of Medivation, Inc. by merger. From 1998 until 2001, Dr. Hung was employed by ProDuct Health, Inc., a privately held medical device company, as chief scientific officer from 1998 to 1999 and as president and chief executive officer from 1999 to 2001. Dr. Hung served as a consultant to Cytyc Corporation from 2001 until 2002 to assist with transitional matters related to Cytyc Corporation's acquisition of ProDuct Health, Inc. Dr. Hung was a director and member of the compensation committee of Opexa from 2006 to 2011. Dr. Hung received an M.D. from the University of California, San Francisco, School of Medicine, and an A.B. in Biology from Harvard College.

Public Company Directorships: Formerly a director of Axovant Sciences, Inc. from April 2017 to February 2018 and a director of Medivation, Inc. from 2004 to 2016.

We believe that Mr. Hung is qualified to serve on our Board due to his business leadership experience, his medical background and his experience as an executive in our industry and as the chief executive officer of both clinical and commercial stage pharmaceutical companies.

Sherilyn D. McCoy

Experience: From 2012 to 2018, Ms. McCoy was the chief executive officer of Avon Products, Inc., a direct selling company in beauty, household, and personal care categories. Prior to joining Avon, Ms. McCoy had various roles at Johnson & Johnson, a multinational medical devices, pharmaceutical and consumer packaged goods manufacturing company, during her distinguished 30-year career, most recently serving as vice chairman of the executive committee and member of the office of the chairman, where she was responsible for the pharmaceutical and consumer business divisions of the company. She was appointed as the Vice Chairman in January 2011. Ms. McCoy holds a B.A. in textile chemistry from the University of Massachusetts, Dartmouth, a Masters in chemical engineering from Princeton University, and an MBA from Rutgers University. Ms. McCoy holds four U.S. patents and she has been on Fortune magazine's “50 Most Powerful Women in Business", a list on which she has been included since 2008. In August 2012, she was recognized as the 39th most powerful woman in the world by Forbes Magazine.

Public Company Directorships: Director of AstraZeneca PLC since 2017. Ms. McCoy has been nominated by the board of Stryker Corporation to be elected as a director at the company's annual meeting of shareholders in May 2018. Formerly a director of Avon Products, Inc. from 2012 to 2018.

We believe that Ms. McCoy is qualified to serve on our Board due to her general business leadership and innovation experience, her scientific background and her experience as an executive in our industry and as the chief executive officer of a global Fortune 500 company.

Class III Nominees for Election to a Three-Year Term Expiring at the 2021 Annual General Meeting of Shareholders

Asaf Danziger

Experience: Mr. Danziger has served as our Chief Executive Officer since 2002. From 1998 to 2002, Mr. Danziger was CEO of Cybro Medical, a subsidiary of Imagyn Medical Technologies, Inc., a medical products company. Mr. Danziger holds a B.Sc. in material engineering from Ben Gurion University of the Negev, Israel.

Public Company Directorships: None

We believe that Mr. Danziger is qualified to serve on our Board due to his service as our Chief Executive Officer and his extensive knowledge of our Company and industry.

William F. Doyle

Experience: Mr. Doyle has served as our Executive Chairman since 2016, as Chairman of the Board since 2009 and as a member of our Board of Directors since 2004. Mr. Doyle has been the managing director of WFD Ventures LLC, a private venture capital firm he co-founded, since 2002, and from 2014 to 2016 he was also a member of the investment team at Pershing Square Capital Management L.P., a private investment firm. Prior to 2002, Mr. Doyle was a member of Johnson & Johnson's Medical Devices and Diagnostics Group Operating Committee and was vice president, Licensing and Acquisitions. While at Johnson & Johnson, Mr. Doyle was also chairman of the Medical Devices Research and Development Council, and Worldwide president of Biosense-Webster, Inc. and a member of the board of directors of Cordis Corporation and Johnson & Johnson Development Corporation, Johnson & Johnson's venture capital subsidiary. Earlier in his career, Mr. Doyle was a management consultant in the healthcare group of McKinsey & Company. Mr. Doyle holds an S.B. in materials science and engineering from the Massachusetts Institute of Technology and an M.B.A. from Harvard Business School.

Public Company Directorships: Director of Optinose since 2010; director of Minerva Neurosciences, Inc. since 2017.

We believe Mr. Doyle is qualified to serve on our Board due to his business and investment experience and his extensive knowledge of our Company and our industry. Mr. Doyle is a recognized expert in medical devices commercialization with over 20 years' experience in the advanced technology and healthcare industries as an entrepreneur, executive, management consultant and investor.

Charles G. Phillips, III

Experience: From 2008 to 2011, Mr. Phillips served as chief operating officer of Prentice Capital Management, LLC, a private investment management firm. Prior to joining Prentice Capital Management, LLC, Mr. Phillips was a managing director from 1991 to 2002 and president from 1998 to 2001 of Gleacher & Co., an investment banking and management firm. Prior to joining Gleacher & Co., Mr. Phillips held senior positions at other investment banking firms, including nine years at Morgan Stanley, a global financial services firm, where he served as a managing director within the investment banking division and founded and led that firm's high-yield finance activities. Mr. Phillips earned an A.B. from Harvard College and an M.B.A from Harvard Business School.

Public Company Directorships: None.

We believe Mr. Phillips is qualified to serve on our Board due to his extensive business, financial and investment banking experience.

William A. Vernon

Experience: Mr. Vernon has served as our Lead Independent Director since May 2016. Mr. Vernon served as the chief executive officer of Kraft Foods Group, Inc., a food products company, from 2012 to 2014 and also served as its senior advisor through May 2015. From 2009 to 2011, Mr. Vernon served as the president of Kraft Foods North America and an executive vice president of Kraft Foods. From 2006 to 2009, Mr. Vernon served as the healthcare industry partner for Ripplewood Holdings, a private equity firm. From 1982 to 2006, Mr. Vernon held various roles at

Johnson & Johnson. He served as company group chairman of DePuy Orthopaedics, a provider of orthopedic products and services, from 2004 to 2005, president of Centocor, a biotechnology company, from 2001 to 2004 and president of McNeil Consumer Products and Nutritionals, Worldwide, an OTC and nutritional products company, from 1999 to 2001 and president of The Johnson & Johnson-Merck Joint Venture, an OTC remedies company, from 1995 to 1999. Mr. Vernon holds a B.A. in history from Lawrence University and an M.B.A. from Northwestern University's Kellogg School of Management.

Public Company Directorships: Director of McCormick & Company since 2017; director of Intersect ENT Inc., a healthcare equipment company, since 2015; and director of The WhiteWave Foods Company, a food products company, since 2016. Previously a director of Axovant Sciences from 2017 to 2018; director of Medivation, Inc., from 2006 to 2016; and director of the Kraft Foods Group from 2012 to 2015.

We believe Mr. Vernon is qualified to serve on our Board due to his business and investment experience as an executive in our industry and as the former chief executive officer of a global Fortune 500 company, with particular expertise in marketing.

OUR BOARD RECOMMENDS A VOTE “FOR”

THE ELECTION OF EACH NOMINEE NAMED IN THIS PROXY

Class I Directors Continuing in Office until the 2019 Annual General Meeting of Shareholders

William Burkoth

Experience: Mr. Burkoth has worked for the Venture Investments Team of Pfizer Inc., a global biopharmaceutical company, since 2004, currently serving as executive director, where he has responsibility for making direct equity investments in private life-science companies on behalf of Pfizer Inc. Prior to joining Pfizer Inc., from 2002 to 2004, Mr. Burkoth worked in business development at the pharmaceutical companies Galileo Pharmaceuticals, Inc. and IntraBiotics Pharmaceuticals, Inc. From 1999 to 2002, Mr. Burkoth worked as an analyst at Bay City Capital, a life sciences venture capital firm. Mr. Burkoth received a B.A. in chemistry from Whitman College and an M.B.A. from Columbia Business School.

Public Company Directorships: None.

We believe that Mr. Burkoth is qualified to serve on our Board due to his business and financial experience as an investor in, and a director of, companies in the biopharmaceutical and biotechnology industry. Mr. Burkoth’s experience provides our Board with a valuable perspective in the development and marketing of our technology.

Kinyip Gabriel Leung

Experience: Mr. Leung has been the Vice Chairman of our Board since 2011 and was an employee of NovoCure from 2011 to 2016, coordinating Novocure’s global commercial operations. From 2003 to 2010, he worked for OSI Pharmaceuticals, Inc., a specialty pharmaceutical company, prior to its acquisition by Astellas Pharma Inc., last serving as executive vice president of OSI Pharmaceuticals, Inc. (“OSI”) and the President of OSI’s Oncology and

Diabetes Business. Prior to his tenure at OSI, from 1999 to 2003, Mr. Leung served as group vice president of the global prescription business at Pharmacia Corporation, a global pharmaceutical and healthcare company. From 1991 to 1999, Mr. Leung was an executive at Bristol-Myers Squibb Company, a global pharmaceutical and healthcare company. Mr. Leung is a pharmacist and trained at the University of Texas at Austin, where he earned his B.S. with High Honors. Mr. Leung earned his M.S. in Pharmacy from the University of Wisconsin-Madison, with a concentration in pharmaceutical marketing.

Public Company Directorships: Director of Pernix Therapeutics Holdings, Inc. since 2016. He was previously director of Albany Molecular Research Inc. from 2010 to 2016 and director of Delcath Systems, Inc. from 2011 to 2014.

We believe that Mr. Leung is qualified to serve on our Board due to his extensive knowledge of our business as a former employee of NovoCure and his experience in our industry, including global management. Specifically, Mr. Leung was responsible for the launch of erlotinib (Tarceva), a chemotherapy drug for non-small cell lung cancer, while at OSI. While at Pharmacia Corporation, Mr. Leung led its oncology franchise with business and medical affairs operations in over 80 countries. At Bristol-Myers Squibb, he oversaw the growth of chemotherapy drugs Taxol and Paraplatin.

Yoram Palti, M.D., Ph.D.

Experience: Professor Palti was a founder of Novocure in 2000 and has been our Chief Technology Officer, serving as a consultant, since 2000. Professor Palti is a professor emeritus of physiology and biophysics at the Technion – Israel Institute of Technology and the inventor of TTFields. From 1982 to 1993, Professor Palti was the head of the Rappaport Family Institute for Research in the Medical Sciences, the research arm of the Technion Medical School. From 1968 to 1970, Professor Palti was an associate professor of physiology at the University of Maryland School of Medicine. Professor Palti also founded and managed Carmel Biosensors Ltd., a private medical technology company, and CellSense Ltd., a private medical technology company, from 1992 to 2000. Professor Palti is the author of more than 40 patents and 70 scientific papers. Professor Palti received his M.Sc., Ph.D. and M.D. from The Hebrew Univ. Hadassah Medical School and served his residency at The Hebrew Univ. Hadassah Medical School.

Public Company Directorships: None.

We believe that Professor Palti is qualified to serve on our Board due to his research qualifications and as the inventor of TTFields. His experience provides extensive knowledge of our technology and our industry.

Class II Directors Continuing in Office until the 2020 Annual General Meeting of Shareholders

Louis J. Lavigne, Jr.

Experience: Mr. Lavigne is the managing director of Lavrite, LLC, a management consulting firm specializing in corporate finance, accounting, growth strategy and management, a position he has held since 2005. He is also the managing member of Spring Development Group, LLC, a specialized investor in growth situations, a position he has held since 2010. Finally, he is a member and former chairman of the UCSF Benioff Children’s Hospitals Board of Directors and the UCSF Benioff Children’s Hospitals Foundation. From 1982 to 2005, Mr. Lavigne held various positions at Genentech, Inc., a biotechnology company. He joined Genentech in 1982 and was named controller in 1983. In 1986, he was promoted to vice president and assumed the chief financial officer position in 1988. In 1994, Mr. Lavigne became senior vice president and in 1997, he became executive vice president. He earned a B.S. in business administration from Babson College and an M.B.A. from Temple University.

Public Company Directorships: Director of Accuray, Inc. since 2009; director of Depomed, Inc. since 2013; and director of Zynga, Inc. since 2015.

We believe that Mr. Lavigne is qualified to serve on our Board due to his business and accounting experience serving as an executive and director of several biotechnology and oncology companies, in addition to his expertise in corporate growth strategies and management.

Martin J. Madden

Experience: Mr. Madden recently retired after a 30-year career at Johnson & Johnson (1986 to January 2017), where he most recently served as Vice President Research and Development DePuy-Synthes and Vice President Medical Device R&D Transformation from February 2016 to January 2017, as Vice President New Product Development, Medical Devices from July 2015 to February 2016, and as Vice President R&D Global Surgery Group from January 2012 to July 2015. Earlier in his career, Mr. Madden was a medical device engineer and innovator, and a leader of cross-functional teams charged with incubating, developing, and launching new products. Mr. Madden graduated first in his class with honors from Columbia University's MBA program. He is an honors graduate from Carnegie-Mellon University, where he earned a Master's degree in Mechanical Engineering, and a summa cum laude graduate from the University of Dayton, where he earned a Bachelor's degree in Mechanical Engineering.

Public Company Directorships: Microbot Medical Inc. since 2017.

We believe that Mr. Madden is qualified to serve on our Board due to his extensive experience with and his status as a world leader in medical device innovation and new product development. During his thirty year tenure with Johnson & Johnson's medical device organization, Mr. Madden was an innovator and research leader for nearly every medical device business including cardiology, electrophysiology, peripheral vascular surgery, general and colorectal surgery, aesthetics, orthopaedics, sports medicine, spine, and trauma. As an Executive and a Vice-President of Johnson & Johnson, Mr. Madden served on the management boards of Johnson & Johnson's Global Surgery Group, Ethicon, Ethicon Endo-Surgery, DePuy-Synthes, and Cordis, with responsibility for research and development – inclusive of organic and licensed/acquired technology. He was also Chairman of J&J's Medical Device Research Council, with responsibility for talent strategy and technology acceleration.

PROPOSAL 2

APPROVAL AND RATIFICATION OF APPOINTMENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Audit Committee of our Board has engaged EY Global as our independent registered public accounting firm for the year ending December 31, 2018, and is seeking ratification of such appointment by our shareholders at the Annual Meeting. EY Global has audited our financial statements since our inception in 2000. Representatives of EY Global are expected to be present at the Annual Meeting. They will have an opportunity to make a statement if they so desire and will be available to respond to appropriate questions.

Jersey company law requires us to appoint an auditor at each annual general meeting to hold office from the conclusion of that meeting to the conclusion of the next annual general meeting. It is therefore proposed that the shareholders approve and ratify the reappointment of EY Global as our independent auditor and registered public accounting firm. If our shareholders fail to approve and ratify the selection, our Audit Committee will reconsider whether or not to retain EY Global. Our Audit Committee will determine the fees to be paid to the auditors for the year ending December 31, 2018.

Principal Accountant Fees and Services

The following table provides information regarding the fees incurred to EY Global during the years ended December 31, 2017 and 2016. All fees described below were approved by our Audit Committee.

	Year Ended December 31,	
	2017	2016
Audit Fees [1]	$550,000	$333,000
Audit-Related Fees [2]	70,000	100,000
Tax Fees [3]	98,422	310,888
All Other Fees	10,000	—
Total Fees	$728,422	$743,888

(1) Audit Fees consist of fees billed for professional services performed by EY Global for the audit of our annual financial statements, the review of interim financial statements, and related services that are normally provided in connection with registration statements.
(2) Audit-Related Fees include fees billed by EY Global for assurance and related services that are reasonably related to the performance of the audit or review of our financial statements.
(3) Tax Fees consist of fees for professional services, including tax consulting and compliance and transfer pricing services performed by EY Global.
(4) All Other Fees consist of fees billed by EY Global for compliance services.

Pre-Approval Policies and Procedures

Before an independent registered public accounting firm is engaged by the Company to render audit or non-audit services, our Audit Committee must review the terms of the proposed engagement and pre-approve the engagement.

OUR BOARD AND OUR AUDIT COMMITTEE RECOMMEND A VOTE "FOR" THE APPOINTMENT OF EY GLOBAL AS OUR INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

23

PROPOSAL 3

NON-BINDING ADVISORY VOTE ON THE APPROVAL OF EXECUTIVE COMPENSATION

The Dodd-Frank Act and Section 14A of the Securities Exchange Act of 1934, as amended (the “Exchange Act”) enable our shareholders to approve, on a non-binding, advisory basis, the compensation of our named executive officers as disclosed in "Compensation Discussion & Analysis," the 2017 Summary Compensation Table and the related compensation tables, notes, and narrative in this Proxy Statement. This proposal, known as a "Say-on-Pay" proposal, gives our shareholders the opportunity to express their views on our named executive officers' compensation as a whole. This vote is not intended to address any specific item of compensation or any specific named executive officer, but rather the overall compensation of all of our named executive officers and the philosophy, policies and practices described in this Proxy Statement.

The Say-on-Pay vote is advisory and, therefore, it is not binding on us, our Board or our Compensation Committee. The Say-on-Pay vote will, however, provide information to us regarding investor sentiment about our executive compensation philosophy, policies and practices, which our Compensation Committee and our Board will consider when determining executive compensation following the annual meeting.

Our compensation programs are designed to support our business goals and promote our long-term profitable growth. Our equity plans are intended to align compensation with the long-term interests of our shareholders. We urge shareholders to read the "Compensation Discussion & Analysis" section of this Proxy Statement, which describes in more detail how our executive compensation policies and procedures operate and are designed to achieve our compensation objectives. We also encourage you to review the 2017 Summary Compensation Table and other related compensation tables and narratives, which provide detailed information on the compensation of our named executive officers. Our Board and our Compensation Committee believe that the policies and procedures described and explained in the "Compensation Discussion & Analysis" are effective in achieving our goals, and that the compensation of our named executive officers reported in this Proxy Statement has supported and contributed to the Company's recent and long-term success. Accordingly, we ask our shareholders to vote "FOR" the approval of our executive compensation on a non-binding advisory basis.

OUR BOARD RECOMMENDS A VOTE "FOR" THE APPROVAL, ON A NON-BINDING ADVISORY BASIS,

OF THE COMPENSATION OF OUR NAMED EXECUTIVE OFFICERS

PROPOSAL 4

NON-BINDING ADVISORY VOTE TO APPROVE THE FREQUENCY OF THE ADVISORY VOTE ON EXECUTIVE COMPENSATION

The Dodd-Frank Act enables our shareholders to indicate, at least once every six years, how frequently we should seek a non-binding vote on the compensation of our named executive officers, as disclosed pursuant to the SEC's compensation disclosure rules. By voting on this Proposal No. 4, shareholders may indicate whether they would prefer a non-binding vote on named executive officer compensation once every one, two, or three years, or shareholders may abstain from voting.

Our Board believes that it is appropriate to give our shareholders the opportunity to provide regular input on our executive compensation program though an advisory vote. Accordingly, our Board recommends that you vote to hold an advisory vote on executive compensation every one year.

We understand that our shareholders may have different views as to what is the best approach for the Company, and we look forward to hearing from our shareholders on this Proposal.

You may cast your vote on your preferred voting frequency by choosing the option of one year, two years, three years, or abstain from voting when you vote in response to the resolution set forth below:

"RESOLVED, that the shareholders advise the Company to hold a non-binding advisory shareholder vote to approve the compensation paid to the Company's named executive officers every:

- one year;
- two years; or
- three years."

The affirmative vote of the simple majority of votes cast is required to approve one year, two years or three years as the shareholders' recommended frequency on this proposal. If none of the options receive the vote of a majority, the option receiving the greatest number of votes will be considered the frequency recommended by our shareholders. However, because this vote is advisory and not binding on the Company, our Compensation Committee or our Board in any way, we may decide that it is in the best interests of our shareholders and the Company to hold an advisory vote on executive compensation more or less frequently than the vote frequency approved by our shareholders.

OUR BOARD RECOMMENDS A VOTE FOR EVERY "ONE YEAR" AS THE FREQUENCY OF THE ADVISORY VOTE ON EXECUTIVE COMPENSATION

PROPOSAL 5

APPROVAL OF THE AMENDMENT OF THE ARTICLES TO REMOVE THE CLASSIFIED STRUCTURE OF OUR BOARD AND PROVIDE FOR THE ANNUAL ELECTION OF DIRECTORS AND TO ALLOW APPOINTMENT OF NEW DIRECTORS BETWEEN ANNUAL MEETINGS

We are requesting that our shareholders approve an amendment to our Articles to remove the classified structure of our Board and provide that all directors will be elected on an annual basis for a term of one year, following a phase-in period as described further below. Our Articles currently provide that our Board be divided into three classes of roughly equal size (Class I, Class II and Class III), with each class holding office for a three-year term. The terms of the classes are staggered, meaning that only one of the three classes stands for re-election at each annual meeting of shareholders. Declassifying our Board will allow our shareholders to vote on the election of our entire Board each year, rather than on a staggered basis.

If the proposed amendment is adopted and becomes effective, declassification of our Board would commence with the 2019 annual meeting and would be phased-out over a three-year period, resulting in the classified Board being fully phased-out (and all directors standing for annual elections) at our 2021 annual meeting. All directors elected at or after the 2019 annual meeting will stand for election and serve for terms expiring at our next annual meeting of shareholders. The Class II and Class III directors standing for election at the 2018 Annual Meeting will still serve two-year and three-year terms, respectively. To further illustrate the phase-out of our classified Board, assuming our shareholders approve the amendment to our Articles, please see below:

- At the 2019 annual meeting, Class I directors will be elected for a one-year term;
- At the 2020 annual meeting, Class I and Class II directors will be elected for a one-year term; and
- At the 2021 annual meeting and all annual meetings thereafter, all directors will be elected for one-year terms and the Board will no longer be classified.

In addition, the proposed amendment will allow our Board to appoint new directors to the Board between annual meetings. Our Articles currently provide that our Board can fill director vacancies on the Board due to death, resignation or retirement between annual meetings, but new directors can only be added to our Board by election at a shareholder meeting. Our Board believes that having the flexibility to add new directors between annual meetings will allow the Board to enhance the talent, skills and diversity of the Board over time as qualified director candidates become available for service on our Board. Any new director appointed by the Board would serve until the next annual meeting of shareholders, at which time the new director would stand for election at that annual meeting.

The full text of the proposed amendment that would become effective upon shareholder approval of this proposal (after which it will be filed with the Companies Registry of the Jersey Financial Services Commission in Jersey) is attached to this proxy statement as Appendix A, with additions of text indicated by underlining and deletions of text indicated by strike-outs. The description of the proposed amendment above is only a summary and is qualified in its entirety by reference to the actual text of the proposed amendment set forth in Appendix A.

After due consideration of corporate trends, peer practices, the guidelines of proxy advisory firms and general views of institutional shareholders, our Nominating and Corporate Governance Committee recommended to our Board the proposed amendment to our Articles to declassify our Board. Our Board subsequently approved and adopted the proposed amendment in March 2018, subject to shareholder approval at the Annual Meeting. The Board determined that declassification of the Board would be in the best interests of the Company and our shareholders.

In making its decision, our Board considered the possible advantages of the classified structure, particularly for newly-public companies and companies with a unique business and a long-term vision, such as board stability and continuity and ensuring a majority of directors have significant experience with our business. A classified board also offers some protection from unsolicited takeover offers that may not be in shareholders’ best interests. However, the Board also considered the view that a classified structure reduces director accountability to shareholders since shareholders are not able to express a view on each director’s performance through an annual vote. In addition, some institutional shareholders believe an annual vote of directors enhances the ability of shareholders to influence corporate governance policies and to hold management accountable for implementation of those policies.

If the proposal is not approved, our Articles will not be amended as set forth in Appendix A, our directors will continue to be elected in three classes and our Board will not be able to appoint new directors between annual meetings. Our Board believes that the amendment of our Articles to remove the classified structure of our Board, provide for the annual election of directors and allow our Board to appoint new directors between annual meetings is in the best interests of the Company and its shareholders for the reasons stated above.

OUR BOARD RECOMMENDS A VOTE "FOR" THE APPROVAL OF THE AMENDMENT OF THE ARTICLES TO REMOVE THE CLASSIFIED STRUCTURE OF OUR BOARD, PROVIDE FOR THE ANNUAL ELECTION OF DIRECTORS, AND ALLOW FOR THE APPOINTMENT OF NEW DIRECTORS BETWEEN ANNUAL MEETINGS

REPORT OF THE AUDIT COMMITTEE OF THE BOARD OF DIRECTORS

The following Audit Committee Report does not constitute soliciting material and shall not be deemed filed or incorporated by reference into any other filings by the Company under the Securities Act of 1933, as amended or under the Exchange Act (the “Securities Act”), except to the extent we specifically incorporate this Report by reference.

Our Audit Committee oversees the Company’s corporate accounting and financial reporting process on behalf of our Board. Management has the primary responsibility for the consolidated financial statements and the reporting process, including the Company’s systems of internal controls. In fulfilling its oversight responsibilities, our Audit Committee reviewed and discussed with management the audited consolidated financial statements filed in the Company’s Annual Report, including a discussion of the quality, not just acceptability, of the accounting principles applied, the reasonableness of significant judgments and the clarity of disclosures in the consolidated financial statements. Our Audit Committee is comprised entirely of independent directors as defined by applicable NASDAQ listing standards.

Our Audit Committee has discussed with EY Global, the Company’s independent registered public accounting firm, the matters required to be discussed by the applicable requirements of the Public Company Accounting Oversight Board and the SEC. Our Audit Committee has received the written disclosures and the letter from EY Global required by applicable requirements of the Public Company Accounting Oversight Board regarding EY Global’s communications with our Audit Committee concerning independence and has discussed with EY Global its independence. Our Audit Committee also considered whether EY Global’s provision of any non-audit services to the Company is compatible with maintaining EY Global’s independence.

Based on the review and discussions described above, among other things, our Audit Committee recommended to our Board that the audited financial statements be included in the Company’s Annual Report for filing with the SEC. Our Audit Committee also approved the selection of the Company’s independent registered public accounting firm.

AUDIT COMMITTEE

Louis J. Lavigne, Jr., Chairman

Martin J. Madden

Charles G. Phillips III

CORPORATE GOVERNANCE

Independence of the Board of Directors

Our Board undertook a review of the independence of our directors (including director nominees David Hung and Sherilyn McCoy), and considered whether any director has a material relationship with us that could compromise his or her ability to exercise independent judgment in carrying out his or her responsibilities. Based upon information requested from and provided by each director concerning his or her background, employment and affiliations, including family relationships and all other facts and circumstances our Board deemed relevant in determining their independence, including beneficial ownership of our ordinary shares, our Board has determined that neither Ms. McCoy nor Messrs. Burkoth, Hung, Lavigne, Madden, Phillips and Vernon has a relationship that would interfere with the exercise of independent judgment in carrying out the responsibilities of a director and that each of these directors is “independent” as that term is defined under the rules of NASDAQ. Mr. Danziger and Mr. Doyle are not considered independent because they are employees of the Company. Mr. Leung is not considered independent because he has been an employee of the Company within the past three years and Professor Palti is not considered independent because of the amount of compensation he received in 2017 as a consultant to the Company.

Board Leadership Structure

Given the unique nature of our business as the first commercialized oncology medical device company, we believe that our leadership structure positions our Company for continued long-term growth. We currently have an Executive Chairman, a separate Chief Executive Officer who also serves on our Board, and a Lead Independent Director. Our Executive Chairman, Mr. Doyle, and Chief Executive Officer, Mr. Danziger, work closely together, in consultation with our Lead Independent Director, Mr. Vernon, to set the strategic direction of the Company. Mr. Doyle, who has been involved with our Company as either an investor or an employee since 2004, focuses on Board leadership, strategic planning and initiatives, investor relations, business development, advocacy and public policy matters. Mr. Danziger, an industry veteran who has been with our Company since 2002, primarily focuses on strategically managing our growing global business, driving operational performance, personnel development and other key business matters. The Board believes this separation of responsibilities is optimal for us at this time, as it will enhance our Board’s oversight by leveraging the clearly defined responsibilities of our Executive Chairman and our Chief Executive Officer and permits Mr. Danziger to focus on operating and managing our Company following our transition to a publicly-traded company. Our leadership structure ensures a seamless flow of communication between management and our Board, in particular with respect to our Board’s oversight of the Company’s strategic direction, as well as our Board’s ability to ensure management’s focused execution of that strategy. Our Lead Independent Director balances our Executive Chairman and Chief Executive Officer roles, providing independent leadership of our Board and exercising critical duties in the boardroom to ensure effective and independent Board decision-making.

Our Corporate Governance Guidelines provide that if the Chairman of our Board is not an independent director (as determined by our Board or our Nominating and Corporate Governance Committee), our independent directors have the discretion to annually elect an independent director to serve as Lead Independent Director. Although elected annually, our Lead Independent Director is generally expected to serve for more than one year. To facilitate this decision-making, our Nominating and Corporate Governance Committee annually discusses our Board leadership structure, providing its recommendation on the appropriate structure for the following year to our independent directors. Our independent directors do not view any particular Board leadership structure as generally preferred; they make an informed annual determination taking into account our financial and operational strategies and any feedback received from our shareholders.

Our Corporate Governance Guidelines clearly delineate the responsibilities of the Lead Independent Director, which are as follows:

- Preside over executive sessions of independent directors and meetings of our Board at which the Executive Chairman is not present, including executive sessions of the independent directors;
- Serve as liaison between the Executive Chairman and Chief Executive Officer and our independent directors;
- Review matters such as meeting agendas and schedules and other information sent to our Board to ensure that appropriate items are discussed, with sufficient time for discussion of all items;
- Call meetings of our independent directors when necessary or appropriate; and
- If requested by significant shareholders, consult and directly communicate with our shareholders.

In addition to these responsibilities, our Lead Independent Director regularly consults with our Executive Chairman and our Chief Executive Officer to help guide management's ongoing engagement with our Board on our strategies and related risks.

Supplementing our Lead Independent Director in providing independent Board leadership are our committee chairs, all of whom are independent. Our Nominating and Corporate Governance Committee evaluated the performance of our Board, including its interactions with our executive management team, in fourth quarter 2017, and discussed its evaluation in executive session with our independent directors. Based on these evaluations, we believe our current Board leadership structure provides effective independent oversight of our Company.

Role of Board in Risk Oversight Process

Risk assessment and oversight are an integral part of our governance and management processes. Our Board as a whole and through various committees of the Board administers the risk management function, monitoring exposure to and mitigation of a variety of risks, including operational, financial, legal and regulatory, strategic and reputational risks. Our Board's approach to risk oversight is designed to support the achievement of organizational objectives, improve long-term organizational performance and enhance shareholder value. A fundamental part of our risk oversight is not only understanding the risks we face and what steps management is taking to manage those risks, but also understanding what level of risk is appropriate for us. In setting our business strategy, our Board assesses the various risks being mitigated by management and determines what constitutes an appropriate level of risk for our Company.

Our Board committees consider risks within their respective areas of oversight responsibility and advise the Board of any significant risks and management's response to those risks via periodic committee reports to the full Board. Our Audit Committee is responsible for overseeing our major financial risk exposures and the steps our management has taken to monitor, as well as overseeing the performance of our internal audit function and considering and approving or disapproving any related party transactions. Our Compensation Committee assesses and monitors risks relating to our compensation programs and policies. The results of the compensation risk assessment are described below under "Risk Considerations in Our Compensation Program." Our Nominating and Corporate Governance Committee considers risks relating to our corporate governance and the marketing, promotion and sale of products. In addition, our Board reviews and assesses information regarding cybersecurity risks with management.

While the Board oversees risk management, our management team is responsible for managing risk on a day-to-day basis. Our Board encourages management to promote a culture that incorporates risk management into our corporate strategy and day-to-day business operations. Management discusses strategic and operational risks at regular management meetings, and conducts specific strategic planning and review sessions during the year that include a focused discussion and analysis of the risks facing us. Throughout the year, senior management reviews these risks with our Board at regular board meetings as part of management presentations that focus on particular business functions, operations or strategies, and presents the steps taken by management to mitigate or eliminate such risks.

Board Committees

Our Board has three standing committees: Audit, Compensation and Nominating and Corporate Governance. The charters of each committee are available to shareholders in the "Corporate Governance" section of our investor relations website at www.novocure.com.

The following table shows the current membership of these committees:

Director	Audit Committee	Compensation Committee	Nominating and Corporate Governance Committee
Asaf Danziger			
William F. Doyle			
Kinyip Gabriel Leung			
Yoram Palti, M.D., Ph.D.			
William Burkoth			X
Louis J. Lavigne, Jr.	Chair		
Martin J. Madden	X		X
Gert Lennart Perlhagen		X	
Charles G. Phillips III	X	Chair	
William A. Vernon		X	Chair

Audit Committee Financial Expert

The principal responsibilities of each of these committees are described generally below and in greater detail in their respective committee charters.

Audit Committee

Our Audit Committee oversees our corporate accounting and financial reporting process. Our Audit Committee is responsible for, among other things:

- appointing our independent registered public accounting firm;

- evaluating the independent registered public accounting firm's qualifications, independence and performance;
- determining the terms of our engagement of our independent registered public accounting firm;
- reviewing and approving the scope of the annual audit and the audit fee;
- reviewing and discussing the adequacy and effectiveness of our accounting and financial reporting processes and internal controls and the audits of our financial statements;
- reviewing and approving, in advance, all audit and non-audit services to be performed by our independent registered public accounting, taking into consideration whether the independent auditor's provision of non-audit services to us is compatible with maintaining the independent auditor's independence;

- monitoring and ensuring the rotation of partners of the independent registered public accounting firm on our engagement team as required by law;
- establishing and overseeing procedures for the receipt, retention and treatment of complaints received by us regarding accounting, internal controls or auditing matters, including procedures for the confidential, anonymous submission by our employees of complaints regarding questionable accounting or auditing matters and reviewing such complaints;
- reviewing and approving related party transactions;
- investigating any matter brought to its attention within the scope of its duties and engaging independent counsel and other advisors as our Audit Committee deems necessary;
- reviewing reports to management prepared by the internal audit function, if any, as well as management's responses;
- reviewing our financial statements and our management's discussion and analysis of financial condition and results of operations to be included in our annual quarterly reports to be filed with the SEC;
- reviewing, at least annually, the Audit Committee charter and the committee's performance; and
- handling such other matters that are specifically delegated to our Audit Committee by our Board from time to time.

All members of our Audit Committee meet the requirements for financial literacy under the applicable rules of NASDAQ. Mr. Lavigne and Mr. Phillips qualify and serve as an audit committee financial expert as defined under the applicable rules and regulations of the SEC. Under the rules and regulations of the SEC and NASDAQ, members of our Audit Committee must also meet independence standards under Rule 10A-3 of the Exchange Act. All members of our Audit Committee meet the applicable independence standards under NASDAQ rules and Rule 10A-3 of the Exchange Act.

Compensation Committee

Our Compensation Committee reviews and recommends policies relating to compensation and benefits of our officers, directors, non-employees and employees. Our Compensation Committee is responsible for, among other things:

- discharging our Board's responsibilities relating to compensation of our directors and executive officers;
- overseeing the administration of our overall compensation and employee benefits plans, particularly incentive compensation and equity-based plans;
- periodically reviewing and approving generally our compensation and benefit strategies and policies;
- at least annually, reviewing and approving the corporate goals and objectives relevant to the compensation of our Chief Executive Officer, evaluating the Chief Executive Officer's performance in light of these goals and objectives and setting the Chief Executive Officer's compensation;
- at least annually, reviewing and approving with the input of our Chief Executive Officer, the compensation of our other executive officers and approving employment, consulting, severance, retirement and/or change in control agreements or provisions with respect to any current or former executive officers;
- at least annually, reviewing and approving succession plans for our Chief Executive Officer and other executive officers;
- periodically reviewing and making recommendations to our Board regarding director compensation;

- overseeing the implementation and administration of our equity compensation plans (including reviewing and approving the adoption of new plans or amendments or modifications to existing plans, subject to shareholder approval, as necessary);
- approving or reviewing and making recommendations to our Board with respect to our share-based compensation plans;
- retaining or obtaining the advice of a compensation consultant, independent legal counsel or other adviser (only after taking into consideration certain specified factors identified by the SEC or NASDAQ listing standards), with direct responsibility for the appointment, compensation and oversight of the work of any such compensation consultant, independent legal counsel and other adviser retained by our Compensation Committee;
- reviewing from time to time the Compensation Committee charter and the committee’s performance; and
- exercising such other authorities and responsibilities as may be delegated to our Compensation Committee by our Board from time to time.

Each of the members of our Compensation Committee is a “non-employee” director as defined in Rule 16b-3 promulgated under the Exchange Act, an “outside director” as that term is defined in Section 162(m) of the Internal Revenue Code (the “Code”) and an independent director under applicable NASDAQ rules.

Nominating and Corporate Governance Committee

Our Nominating and Corporate Governance Committee is responsible for, among other things:

- identifying and screening candidates for our Board and recommending nominees for election as directors, as well as recommending one or more “audit committee financial experts” (as defined under applicable SEC rules) for our Audit Committee;
- establishing procedures to exercise oversight of the evaluation of our Board and management;
- developing and recommending to our Board a set of corporate governance guidelines, as well as periodically reviewing these guidelines and recommending any changes to our Board;
- reviewing the structure of our Board committees and recommending to our Board for its approval directors to serve as members of each committee, and where appropriate, making recommendations regarding the removal of any member of any committee;
- reviewing and assessing the adequacy of its formal written charter on an annual basis;
- reviewing the content, operations and effectiveness of the Company’s compliance program as it relates to the marketing, promotion and sale of products on an annual basis that shall include updates and reports by the Company’s Chief Compliance Officer and other compliance personnel on their activities and updates about adoption and implementation of policies, procedures and practices designed to assure compliance with the U.S. Federal Food, Drug and Cosmetic Act, analogous laws in other jurisdictions and other applicable legal requirements;
- reviewing the relationships that each director has with us for purposes of determining independence; and
- generally advising our Board on corporate governance and related matters.

Each of the members of our Nominating and Corporate Governance Committee is an independent director under the rules of NASDAQ.

Meetings of the Board of Directors, Board and Committee Member Attendance, and Annual Meeting Attendance

Our Board met six times during 2017. Our Audit Committee met five times, our Compensation Committee met seven times, our Nominating and Corporate Governance Committee met four times, and our pricing committee (a special committee of independent directors appointed by the Board to oversee our recent financing activities) met two times. During 2017, each Board member attended 75% or more of the aggregate of the meetings of our Board and of the committees on which he served that occurred while such director was a member of our Board and such committees.

We encourage all of our directors and nominees for director to attend our annual general meetings of shareholders. Eight of our directors attended our annual general meeting of shareholders held in May 2017. Two of our directors were unable to attend due to prior commitments.

Director Nomination Process

Our Board seeks members from diverse professional backgrounds who combine a broad spectrum of experience and expertise with a reputation for integrity. In considering diversity of our Board, our Nominating and Corporate Governance Committee will take into account various factors and perspectives, including differences of viewpoint, professional experience, education, skill and other individual qualities and attributes that contribute to Board heterogeneity, as well as race, gender and national origin. Directors should have experience in positions with a high degree of responsibility, be leaders in the companies or institutions with which they are affiliated, and be selected based upon contributions they can make.

Our Nominating and Corporate Governance Committee is responsible for determining the appropriate skills and characteristics required of Board members in the context of its current make-up, and will consider factors such as independence, experience, strength of character, mature judgment and technical skills in its assessment of the needs of our Board and its evaluation of director nominees. Our Board evaluates each individual in the context of our Board as a whole, with the objective of assembling a group that can best maximize the success of the business and represent shareholder interests through the exercise of sound judgment using its diversity of experience in these various areas, amongst others. Our directors' performance and qualification criteria are reviewed annually by our Nominating and Corporate Governance Committee.

Identification and Evaluation of Nominees for Directors

Our Nominating and Corporate Governance Committee identifies nominees for director by first evaluating the current members of our Board willing to continue in service. Current members with qualifications and skills that are consistent with our Nominating and Corporate Governance Committee's criteria for Board service and who are willing to continue in service are considered for re-nomination, balancing the value of continuity of service by existing members of our Board with that of obtaining a new perspective or expertise.

If any member of our Board does not wish to continue in service or if our Board decides not to re-nominate a member for re-election, our Nominating and Corporate Governance Committee may identify the desired skills and experience of a new nominee in light of the criteria above, in which case, our Nominating and Corporate Governance Committee would generally poll our Board and members of management for their recommendations. Our Nominating and Corporate Governance Committee may also review the composition and qualification of the boards of directors of our competitors, and may seek input from industry experts or analysts. Our Nominating and Corporate Governance Committee reviews the qualifications, experience and background of the candidates. Final candidates are interviewed by the members of our Nominating and Corporate Governance Committee and by certain of our other independent directors and executive management as appropriate. In making its determinations, our Nominating and Corporate Governance Committee evaluates each individual in the context of our Board as a whole, with the objective of assembling a group that can best contribute to the success of our Company and represent shareholder interests through the exercise of sound judgment. After review and deliberation of all feedback and data, our Nominating and Corporate Governance Committee makes its recommendation to our Board. To date, our Nominating and Corporate Governance Committee has not utilized third-party search firms to identify director candidates. Our Nominating and Corporate Governance Committee may in the future choose to do so in those situations where particular qualifications are required or where existing contacts are not sufficient to identify an appropriate candidate.

Shareholder Recommendations and Nominations

A shareholder or shareholders holding at least one tenth (1/10th) of the total voting rights of the members who have the right to vote at a general meeting of the shareholders of the Company may propose a person for election to the office of director at an annual meeting. Shareholders may recommend director candidates by written submissions containing the information required by our Articles (and further detailed in the next paragraph) to NovoCure’s company secretary at NovoCure Limited, Second Floor, No. 4 The Forum, Grenville Street, St. Helier, Jersey, Channel Islands JE2 4UF. Our Nominating and Corporate Governance Committee evaluates nominees recommended by shareholders in the same manner as it evaluates other nominees.

For a shareholder to make a formal nomination for election to our Board at an annual meeting, the shareholder must provide advance notice to the Company, which notice must be received by NovoCure’s company secretary at NovoCure Limited, Second Floor, No. 4 The Forum, Grenville Street, St. Helier, Jersey, Channel Islands JE2 4UF, not later than the 90th Clear Day (as defined in our Articles) nor earlier than the 120th Clear Day before the one-year anniversary of the preceding year’s annual meeting; provided, however, that if that the date of the annual meeting is advanced by more than 30 days prior to such anniversary date or delayed by more than 60 days after the anniversary date, then, it must be so received by the company secretary not earlier than the close of business on the 120th Clear Day prior to such annual meeting and not later than the close of business on the later of (i) the 60th Clear Day prior to such annual meeting, or (ii) the tenth Clear Day following the day on which a public announcement of the date of such annual meeting is first made. As set forth in our Articles, submissions must include all information regarding the proposed nominee that is required to be disclosed in a proxy statement or other filings in a contested election pursuant to Regulation 14(a) under the Exchange Act and a written and signed consent of the proposed nominee to be named in the proxy statement as a nominee and to serving as a director if elected. Our Articles also specify further requirements as to the form and content of a shareholder’s notice. We recommend that any shareholder wishing to make a nomination for director review a copy of our Articles, as amended and restated to date, which is available, without charge, from Investor Relations, NovoCure Limited, at 20 Valley Stream Parkway, Suite 300, Malvern, Pennsylvania 19355.

Code of Ethics

We have adopted a written code of business conduct and ethics (the “Code of Ethics”) that applies to our directors, officers and employees, including our principal executive officer and principal financial officer. A current copy of the

Code of Ethics is posted in the "Corporate Governance" section of our investor relations website at www.novocure.com. We intend to disclose any amendment to the Code of Ethics, or any waivers of its requirements, on our website.

$
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[(a)]
$
117,249

$
116,770

See the Combined Notes to Consolidated Financial Statements
13

Table of Contents

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2018	December 31, 2017
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[(a)]	84,410	84,583
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 966 shares and 963 shares outstanding at June 30, 2018 and December 31, 2017, respectively)	19,008	18,964
Treasury stock, at cost (2 shares at June 30, 2018 and December 31, 2017)	(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) Exelon's consolidated assets include $9,612 million and $9,597 million at June 30, 2018 and December 31, 2017, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Exelon's consolidated liabilities include $3,544 million and $3,618 million at June 30, 2018 and December 31, 2017, respectively, of certain VIEs for which the VIE creditors do not have recourse to Exelon. See Note 3 — Variable Interest Entities for additional information.

Table of Contents

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS’ EQUITY
(Unaudited)

(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Shareholders' Equity
Balance, December 31, 2017	965,168	$ 18,964	$ (123)	$ 14,081	$ (3,026)	$ 2,291	$ 32,187
Net income	—	—	—	1,125	—	54	1,179
Long-term incentive plan activity	1,868	17	—	—	—	—	17
Employee stock purchase plan issuances	703	27	—	—	—	—	27
Changes in equity of noncontrolling interests	—	—	—	—	—	(23)	(23)
Common stock dividends	—	—	—	(669)	—	—	(669)
Other comprehensive income, net of income taxes	—	—	—	—	115	2	117
Impact of adoption of Recognition and Measurement of Financial Assets and Liabilities standard	—	—	—	14	(10)	—	4
Balance, June 30, 2018	967,739	$ 19,008	$ (123)	$ 14,551	$ (2,921)	$ 2,324	$ 32,839

See the Combined Notes to Consolidated Financial Statements
15

Table of Contents

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2018	2017	2018	2017
Operating revenues				
Operating revenues	$4,306	$3,948	$9,419	$8,495
Operating revenues from affiliates	273	268	671	598
Total operating revenues	4,579	4,216	10,090	9,093
Operating expenses				
Purchased power and fuel	2,277	2,156	5,566	4,952
Purchased power and fuel from affiliates	3	1	7	3
Operating and maintenance	1,247	1,826	2,425	3,138
Operating and maintenance from affiliates	171	186	331	365
Depreciation and amortization	466	334	914	637
Taxes other than income	134	140	272	282
Total operating expenses	4,298	4,643	9,515	9,377
Gain on sales of assets and businesses	1	—	54	4
Bargain purchase gain	—	—	—	226
Operating income (loss)	282	(427)	629	(54)
Other income and (deductions)				
Interest expense, net	(93)	(120)	(184)	(209)
Interest expense to affiliates	(9)	(9)	(18)	(19)
Other, net	29	181	(15)	440
Total other income and (deductions)	(73)	52	(217)	212
Income (loss) before income taxes	209	(375)	412	158
Income taxes	23	(148)	32	(25)
Equity in losses of unconsolidated affiliates	(5)	(9)	(12)	(19)
Net income (loss)	181	(236)	368	164
Net income (loss) attributable to noncontrolling interests	3	(1)	54	(20)
Net income (loss) attributable to membership interest	$178	$(235)	$314	$184
Comprehensive income, net of income taxes				
Net income (loss)	$181	$(236)	$368	$164
Other comprehensive income (loss), net of income taxes				
Unrealized gain (loss) on cash flow hedges	5	(1)	12	5
Unrealized gain on investments in unconsolidated affiliates	2	—	3	4
Unrealized (loss) gain on foreign currency translation	(5)	2	(6)	3
Other comprehensive income	2	1	9	12
Comprehensive income (loss)	183	(235)	377	176
Comprehensive income (loss) attributable to noncontrolling interests	4	(1)	56	(22)
Comprehensive income (loss) attributable to membership interest	$179	$(234)	$321	$198

See the Combined Notes to Consolidated Financial Statements
16

Table of Contents

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30,	
(In millions)	2018	2017
Cash flows from operating activities		
Net income	$368	$164
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion, including nuclear fuel and energy contract amortization	1,735	1,415
Impairment of long-lived assets	41	445
Gain on sales of assets and businesses	(54)	(4)
Bargain purchase gain	—	(226)
Deferred income taxes and amortization of investment tax credits	(149)	(167)
Net fair value changes related to derivatives	158	235
Net realized and unrealized losses (gains) on nuclear decommissioning trust fund investments	80	(284)
Other non-cash operating activities	85	121
Changes in assets and liabilities:		
Accounts receivable	258	151
Receivables from and payables to affiliates, net	7	8
Inventories	34	(5)
Accounts payable and accrued expenses	(272)	(327)
Option premiums paid, net	(36)	(8)
Collateral received (posted), net	91	(163)
Income taxes	58	(99)
Pension and non-pension postretirement benefit contributions	(129)	(116)
Other assets and liabilities	(212)	(166)
Net cash flows provided by operating activities	2,063	974
Cash flows from investing activities		
Capital expenditures	(1,298)	(1,189)
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	210
Changes in Exelon intercompany money pool	(185)	—
Other investing activities	4	(32)
Net cash flows used in investing activities	(1,549)	(1,349)
Cash flows from financing activities		
Changes in short-term borrowings	—	(51)
Proceeds from short-term borrowings with maturities greater than 90 days	1	76
Repayments of short-term borrowings with maturities greater than 90 days	(1)	(10)
Issuance of long-term debt	13	779
Retirement of long-term debt	(76)	(295)
Changes in Exelon intercompany money pool	(54)	196
Distributions to member	(377)	(330)
Other financing activities	(24)	(7)
Net cash flows (used in) provided by financing activities	(518)	358

Decrease in cash, cash equivalents and restricted cash	(4)	(17)
Cash, cash equivalents and restricted cash at beginning of period	554	448
Cash, cash equivalents and restricted cash at end of period	$550	$431

See the Combined Notes to Consolidated Financial Statements
17

Table of Contents

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$420	$ 416
Restricted cash and cash equivalents	130	138
Accounts receivable, net		
Customer	2,435	2,697
Other	276	321
Mark-to-market derivative assets	799	976
Receivables from affiliates	146	140
Unamortized energy contract assets	46	60
Inventories, net		
Fossil fuel and emission allowances	214	264
Materials and supplies	953	937
Other	1,148	933
Total current assets	6,567	6,882
Property, plant and equipment, net	24,479	24,906
Deferred debits and other assets		
Nuclear decommissioning trust funds	13,110	13,272
Investments	423	433
Goodwill	47	47
Mark-to-market derivative assets	457	334
Prepaid pension asset	1,522	1,502
Unamortized energy contract assets	378	395
Deferred income taxes	6	16
Other	679	670
Total deferred debits and other assets	16,622	16,669
Total assets[(a)]	$47,668	$ 48,457

See the Combined Notes to Consolidated Financial Statements
18

Table of Contents

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2018	December 31, 2017
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$—	$2
Long-term debt due within one year	321	346
Accounts payable	1,264	1,773
Accrued expenses	976	1,022
Payables to affiliates	128	123
Borrowings from Exelon intercompany money pool	—	54
Mark-to-market derivative liabilities	245	211
Unamortized energy contract liabilities	36	43
Renewable energy credit obligation	257	352
Other	295	265
Total current liabilities	3,522	4,191
Long-term debt	7,661	7,734
Long-term debt to affiliate	904	910
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,673	3,811
Asset retirement obligations	10,037	9,844
Non-pension postretirement benefit obligations	907	916
Spent nuclear fuel obligation	1,157	1,147
Payables to affiliates	2,916	3,065
Mark-to-market derivative liabilities	270	174
Unamortized energy contract liabilities	34	48
Other	648	658
Total deferred credits and other liabilities	19,642	19,663
Total liabilities[a]	31,729	32,498
Commitments and contingencies		
Equity		
Member's equity		
Membership interest	9,357	9,357
Undistributed earnings	4,292	4,349
Accumulated other comprehensive loss, net	(33)	(37)
Total member's equity	13,616	13,669
Noncontrolling interests	2,323	2,290
Total equity	15,939	15,959
Total liabilities and equity	$47,668	$48,457

(a) Generation's consolidated assets include $9,575 million and $9,556 million at June 30, 2018 and December 31, 2017, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Generation's consolidated liabilities include $3,456 million and $3,516 million at June 30, 2018 and December 31, 2017, respectively, of certain VIEs for which the VIE creditors do not have recourse to Generation. See Note 3 — Variable Interest Entities for additional information.

See the Combined Notes to Consolidated Financial Statements

Table of Contents

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY
(Unaudited)

(In millions)	Member's Equity				
	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Equity
Balance, December 31, 2017	$9,357	$ 4,349	$ (37)	$ 2,290	$15,959
Net income	—	314	—	54	368
Changes in equity of noncontrolling interests	—	—	—	(23)	(23)
Distributions to member	—	(377)	—	—	(377)
Other comprehensive income, net of income taxes	—	—	7	2	9
Impact of adoption of Recognition and Measurement of Financial Assets and Liabilities standard	—	6	(3)	—	3
Balance, June 30, 2018	$9,357	$ 4,292	$ (33)	$ 2,323	$15,939

See the Combined Notes to Consolidated Financial Statements
20

Table of Contents

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2018	2017	2018	2017
Operating revenues				
Electric operating revenues	$1,410	$1,336	$2,903	$2,615
Revenues from alternative revenue programs	(17)	18	(12)	32
Operating revenues from affiliates	5	3	19	9
Total operating revenues	1,398	1,357	2,910	2,656
Operating expenses				
Purchased power	373	360	784	689
Purchased power from affiliate	104	18	298	24
Operating and maintenance	255	312	509	620
Operating and maintenance from affiliate	69	65	129	127
Depreciation and amortization	231	211	459	419
Taxes other than income	79	72	156	144
Total operating expenses	1,111	1,038	2,335	2,023
Gain on sales of assets	1	—	5	—
Operating income	288	319	580	633
Other income and (deductions)				
Interest expense, net	(82)	(98)	(168)	(179)
Interest expense to affiliates	(3)	(3)	(7)	(6)
Other, net	4	4	12	8
Total other income and (deductions)	(81)	(97)	(163)	(177)
Income before income taxes	207	222	417	456
Income taxes	43	104	88	197
Net income	$164	$118	$329	$259
Comprehensive income	$164	$118	$329	$259

See the Combined Notes to Consolidated Financial Statements
21

Table of Contents

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30,	
(In millions)	2018	2017
Cash flows from operating activities		
Net income	$329	$259
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	459	419
Deferred income taxes and amortization of investment tax credits	84	235
Other non-cash operating activities	117	58
Changes in assets and liabilities:		
Accounts receivable	(133)	12
Receivables from and payables to affiliates, net	15	(4)
Inventories	5	(2)
Accounts payable and accrued expenses	(41)	(182)
Collateral posted, net	(13)	(8)
Income taxes	(15)	4
Pension and non-pension postretirement benefit contributions	(39)	(37)
Other assets and liabilities	(166)	34
Net cash flows provided by operating activities	602	788
Cash flows from investing activities		
Capital expenditures	(1,026)	(1,168)
Other investing activities	17	12
Net cash flows used in investing activities	(1,009)	(1,156)
Cash flows from financing activities		
Changes in short-term borrowings	320	389
Issuance of long-term debt	800	—
Retirement of long-term debt	(700)	—
Contributions from parent	225	184
Dividends paid on common stock	(229)	(211)
Other financing activities	(10)	(1)
Net cash flows provided by financing activities	406	361
Decrease in cash, cash equivalents and restricted cash	(1)	(7)
Cash, cash equivalents and restricted cash at beginning of period	144	58
Cash, cash equivalents and restricted cash at end of period	$143	$51

See the Combined Notes to Consolidated Financial Statements
22

Table of Contents

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$30	$ 76
Restricted cash	5	5
Accounts receivable, net		
Customer	579	559
Other	376	266
Receivables from affiliates	21	13
Inventories, net	146	152
Regulatory assets	237	225
Other	86	68
Total current assets	1,480	1,364
Property, plant and equipment, net	21,323	20,723
Deferred debits and other assets		
Regulatory assets	1,134	1,054
Investments	6	6
Goodwill	2,625	2,625
Receivables from affiliates	2,430	2,528
Prepaid pension asset	1,130	1,188
Other	318	238
Total deferred debits and other assets	7,643	7,639
Total assets	$30,446	$ 29,726

See the Combined Notes to Consolidated Financial Statements

Table of Contents

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2018	December 31, 2017
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$320	$—
Long-term debt due within one year	440	840
Accounts payable	547	568
Accrued expenses	285	327
Payables to affiliates	97	74
Customer deposits	111	112
Regulatory liabilities	287	249
Mark-to-market derivative liability	23	21
Other	81	103
Total current liabilities	2,191	2,294
Long-term debt	7,255	6,761
Long-term debt to financing trust	205	205
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,597	3,469
Asset retirement obligations	111	111
Non-pension postretirement benefits obligations	210	219
Regulatory liabilities	6,221	6,328
Mark-to-market derivative liability	229	235
Other	560	562
Total deferred credits and other liabilities	10,928	10,924
Total liabilities	20,579	20,184
Commitments and contingencies		
Shareholders' equity		
Common stock	1,588	1,588
Other paid-in capital	7,047	6,822
Retained deficit unappropriated	(1,639)	(1,639)
Retained earnings appropriated	2,871	2,771
Total shareholders' equity	9,867	9,542
Total liabilities and shareholders' equity	$30,446	$29,726

See the Combined Notes to Consolidated Financial Statements
24

Table of Contents

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY
(Unaudited)

(In millions)	Common Stock	Other Paid-In Capital	Retained Deficit Unappropriated	Retained Earnings Appropriated	Total Shareholders' Equity
Balance, December 31, 2017	$ 1,588	$ 6,822	$ (1,639)	$ 2,771	$ 9,542
Net income	—	—	329	—	329
Appropriation of retained earnings for future dividends	—	—	(329)	329	—
Common stock dividends	—	—	—	(229)	(229)
Contributions from parent	—	225	—	—	225
Balance, June 30, 2018	$ 1,588	$ 7,047	$ (1,639)	$ 2,871	$ 9,867

See the Combined Notes to Consolidated Financial Statements
25

Table of Contents

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2018	2017	2018	2017
Operating revenues				
Electric operating revenues	$556	$548	$1,189	$1,138
Natural gas operating revenues	93	80	325	285
Revenues from alternative revenue programs	2	—	1	—
Operating revenues from affiliates	2	2	3	3
Total operating revenues	653	630	1,518	1,426
Operating expenses				
Purchased power	161	136	361	292
Purchased fuel	37	27	134	113
Purchased power from affiliate	24	34	60	79
Operating and maintenance	153	153	387	326
Operating and maintenance from affiliates	38	37	79	72
Depreciation and amortization	74	71	149	141
Taxes other than income	39	35	79	74
Total operating expenses	526	493	1,249	1,097
Operating income	127	137	269	329
Other income and (deductions)				
Interest expense, net	(28)	(28)	(57)	(56)
Interest expense to affiliates	(4)	(3)	(7)	(6)
Other, net	—	2	2	3
Total other income and (deductions)	(32)	(29)	(62)	(59)
Income before income taxes	95	108	207	270
Income taxes	(1)	20	(3)	55
Net income	$96	$88	$210	$215
Comprehensive income	$96	$88	$210	$215

See the Combined Notes to Consolidated Financial Statements
26

Table of Contents

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30,	
(In millions)	2018	2017
Cash flows from operating activities		
Net income	$210	$215
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	149	141
Deferred income taxes and amortization of investment tax credits	(10)	39
Other non-cash operating activities	22	22
Changes in assets and liabilities:		
Accounts receivable	(43)	26
Receivables from and payables to affiliates, net	(4)	(10)
Inventories	4	7
Accounts payable and accrued expenses	(18)	(30)
Income taxes	19	51
Pension and non-pension postretirement benefit contributions	(25)	(23)
Other assets and liabilities	(50)	(70)
Net cash flows provided by operating activities	254	368
Cash flows from investing activities		
Capital expenditures	(411)	(367)
Changes in Exelon intercompany money pool	—	121
Other investing activities	5	4
Net cash flows used in investing activities	(406)	(242)
Cash flows from financing activities		
Changes in short-term borrowings	50	—
Issuance of long-term debt	375	—
Retirement of long-term debt	(500)	—
Changes in Exelon intercompany money pool	233	—
Contributions from parent	41	—
Dividends paid on common stock	(293)	(144)
Other financing activities	(6)	—
Net cash flows used in financing activities	(100)	(144)
Decrease in cash, cash equivalents and restricted cash	(252)	(18)
Cash, cash equivalents and restricted cash at beginning of period	275	67
Cash, cash equivalents and restricted cash at end of period	$23	$49

See the Combined Notes to Consolidated Financial Statements
27

Table of Contents

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$18	$ 271
Restricted cash and cash equivalents	5	4
Accounts receivable, net		
Customer	285	327
Other	178	105
Receivable from affiliates	—	—
Inventories, net		
Fossil fuel	24	31
Materials and supplies	33	30
Prepaid utility taxes	72	8
Regulatory assets	75	29
Other	25	17
Total current assets	715	822
Property, plant and equipment, net	8,307	8,053
Deferred debits and other assets		
Regulatory assets	427	381
Investments	25	25
Receivable from affiliates	485	537
Prepaid pension asset	355	340
Other	31	12
Total deferred debits and other assets	1,323	1,295
Total assets	$10,345	$ 10,170

See the Combined Notes to Consolidated Financial Statements
28

Table of Contents

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2018	December 31, 2017
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$50	$ —
Long-term debt due within one year	—	500
Accounts payable	349	370
Accrued expenses	118	114
Payables to affiliates	48	53
Borrowings from Exelon intercompany money pool	233	—
Customer deposits	67	66
Regulatory liabilities	168	141
Other	32	23
Total current liabilities	1,065	1,267
Long-term debt	2,773	2,403
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,854	1,789
Asset retirement obligations	27	27
Non-pension postretirement benefits obligations	288	288
Regulatory liabilities	545	549
Other	74	86
Total deferred credits and other liabilities	2,788	2,739
Total liabilities	6,810	6,593
Commitments and contingencies		
Shareholder’s equity		
Common stock	2,530	2,489
Retained earnings	1,005	1,087
Accumulated other comprehensive income, net	—	1
Total shareholder’s equity	3,535	3,577
Total liabilities and shareholder's equity	$10,345	$ 10,170

See the Combined Notes to Consolidated Financial Statements
29

Table of Contents

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDER'S EQUITY
(Unaudited)

(In millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income, net	Total Shareholder's Equity
Balance, December 31, 2017	$ 2,489	$ 1,087	$ 1	$ 3,577
Net income	—	210	—	210
Common stock dividends	—	(293)	—	(293)
Contributions from parent	41	—	—	41
Impact of adoption of Recognition and Measurement of Financial Assets and Liabilities standard	—	1	(1)	—
Balance, June 30, 2018	$ 2,530	$ 1,005	$ —	$ 3,535

See the Combined Notes to Consolidated Financial Statements
30

Table of Contents

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2018	2017	2018	2017
Operating revenues				
Electric operating revenues	$542	$545	$1,196	$1,186
Natural gas operating revenues	118	94	448	365
Revenues from alternative revenue programs	(4)	32	(17)	66
Operating revenues from affiliates	6	3	12	8
Total operating revenues	662	674	1,639	1,625
Operating expenses				
Purchased power	135	115	327	248
Purchased fuel	32	22	155	105
Purchased power from affiliate	62	97	127	231
Operating and maintenance	135	135	318	284
Operating and maintenance from affiliates	41	39	79	73
Depreciation and amortization	114	112	248	239
Taxes other than income	59	56	124	119
Total operating expenses	578	576	1,378	1,299
Gain on sales of assets	1	—	1	—
Operating income	85	98	262	326
Other income and (deductions)				
Interest expense, net	(25)	(22)	(51)	(46)
Interest expense to affiliates	—	(4)	—	(8)
Other, net	4	4	9	8
Total other income and (deductions)	(21)	(22)	(42)	(46)
Income before income taxes	64	76	220	280
Income taxes	13	31	41	111
Net income	$51	$45	$179	$169
Comprehensive income	$51	$45	$179	$169

See the Combined Notes to Consolidated Financial Statements

Table of Contents

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Six Months Ended June 30, 2018	2017
Cash flows from operating activities		
Net income	$179	$169
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	248	239
Deferred income taxes and amortization of investment tax credits	39	99
Other non-cash operating activities	27	35
Changes in assets and liabilities:		
Accounts receivable	73	77
Receivables from and payables to affiliates, net	(4)	(7)
Inventories	5	(5)
Accounts payable and accrued expenses	(48)	(83)
Income taxes	(45)	26
Pension and non-pension postretirement benefit contributions	(49)	(47)
Other assets and liabilities	39	(34)
Net cash flows provided by operating activities	464	469
Cash flows from investing activities		
Capital expenditures	(434)	(405)
Other investing activities	6	4
Net cash flows used in investing activities	(428)	(401)
Cash flows from financing activities		
Changes in short-term borrowings	59	40
Retirement of long-term debt	—	(41)
Dividends paid on common stock	(105)	(99)
Net cash flows used in financing activities	(46)	(100)
Decrease in cash, cash equivalents and restricted cash	(10)	(32)
Cash, cash equivalents and restricted cash at beginning of period	18	50
Cash, cash equivalents and restricted cash at end of period	$8	$18

See the Combined Notes to Consolidated Financial Statements

Table of Contents

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$7	$ 17
Restricted cash and cash equivalents	1	1
Accounts receivable, net		
Customer	300	375
Other	89	94
Receivables from affiliates	—	1
Inventories, net		
Gas held in storage	27	37
Materials and supplies	45	40
Prepaid utility taxes	—	69
Regulatory assets	185	174
Other	4	3
Total current assets	658	811
Property, plant and equipment, net	7,864	7,602
Deferred debits and other assets		
Regulatory assets	405	397
Investments	6	5
Prepaid pension asset	302	285
Other	6	4
Total deferred debits and other assets	719	691
Total assets	$9,241	$ 9,104

See the Combined Notes to Consolidated Financial Statements
33

Table of Contents

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2018	December 31, 2017
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$136	$ 77
Accounts payable	249	265
Accrued expenses	95	164
Payables to affiliates	48	52
Customer deposits	120	116
Regulatory liabilities	106	62
Other	23	24
Total current liabilities	777	760
Long-term debt	2,578	2,577
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,306	1,244
Asset retirement obligations	23	23
Non-pension postretirement benefits obligations	199	202
Regulatory liabilities	1,070	1,101
Other	73	56
Total deferred credits and other liabilities	2,671	2,626
Total liabilities	6,026	5,963
Commitments and contingencies		
Shareholders' equity		
Common stock	1,605	1,605
Retained earnings	1,610	1,536
Total shareholders' equity	3,215	3,141
Total liabilities and shareholders' equity	$9,241	$ 9,104

See the Combined Notes to Consolidated Financial Statements
34

Table of Contents

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY
(Unaudited)

(In millions)	Common Stock	Retained Earnings	Total Shareholders' Equity
Balance, December 31, 2017	$ 1,605	$ 1,536	$ 3,141
Net income	—	179	179
Common stock dividends	—	(105)	(105)
Balance, June 30, 2018	$ 1,605	$ 1,610	$ 3,215

See the Combined Notes to Consolidated Financial Statements

Table of Contents

PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2018	2017	2018	2017
Operating revenues				
Electric operating revenues	$1,052	$1,032	$2,202	$2,100
Natural gas operating revenues	28	22	106	87
Revenues from alternative revenue programs	(7)	8	12	38
Operating revenues from affiliates	3	12	7	23
Total operating revenues	1,076	1,074	2,327	2,248
Operating expenses				
Purchased power	288	259	662	547
Purchased fuel	12	9	53	39
Purchased power and fuel from affiliates	81	115	186	259
Operating and maintenance	218	231	489	454
Operating and maintenance from affiliates	37	38	74	70
Depreciation, amortization and accretion	180	165	363	332
Taxes other than income	107	110	221	221
Total operating expenses	923	927	2,048	1,922
Gain on sales of assets	—	1	—	1
Operating income	153	148	279	327
Other income and (deductions)				
Interest expense, net	(65)	(59)	(128)	(122)
Other, net	11	13	22	26
Total other income and (deductions)	(54)	(46)	(106)	(96)
Income before income taxes	99	102	173	231
Income taxes	15	36	24	26
Net income	$84	$66	$149	$205
Comprehensive income	$84	$66	$149	$205

See the Combined Notes to Consolidated Financial Statements
36

Table of Contents

PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30,	
(In millions)	2018	2017
Cash flows from operating activities		
Net income	$149	$205
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	363	332
Gain on sales of long-lived assets	—	(1)
Deferred income taxes and amortization of investment tax credits	14	59
Other non-cash operating activities	71	28
Changes in assets and liabilities:		
Accounts receivable	(28)	(3)
Receivables from and payables to affiliates, net	4	(7)
Inventories	8	(19)
Accounts payable and accrued expenses	66	(61)
Income taxes	13	87
Pension and non-pension postretirement benefit contributions	(62)	(68)
Other assets and liabilities	(111)	(149)
Net cash flows provided by operating activities	487	403
Cash flows from investing activities		
Capital expenditures	(629)	(671)
Proceeds from sales of long-lived assets	—	1
Other investing activities	2	—
Net cash flows used in investing activities	(627)	(670)
Cash flows from financing activities		
Changes in short-term borrowings	(228)	45
Proceeds from short-term borrowings with maturities greater than 90 days	125	—
Repayments of short-term borrowings with maturities greater than 90 days	—	(500)
Issuance of long-term debt	300	202
Retirement of long-term debt	(25)	(120)
Distributions to member	(109)	(131)
Contributions from member	235	751
Change in Exelon intercompany money pool	7	—
Other financing activities	(7)	(2)
Net cash flows provided by financing activities	298	245
Increase (Decrease) in cash, cash equivalents and restricted cash	158	(22)
Cash, cash equivalents and restricted cash at beginning of period	95	236
Cash, cash equivalents and restricted cash at end of period	$253	$214

See the Combined Notes to Consolidated Financial Statements
37

Table of Contents

PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$195	$ 30
Restricted cash and cash equivalents	38	42
Accounts receivable, net		
Customer	495	486
Other	201	206
Inventories, net		
Gas held in storage	5	7
Materials and supplies	145	151
Regulatory assets	512	554
Other	81	75
Total current assets	1,672	1,551
Property, plant and equipment, net	12,929	12,498
Deferred debits and other assets		
Regulatory assets	2,439	2,493
Investments	133	132
Goodwill	4,005	4,005
Long-term note receivable	—	4
Prepaid pension asset	513	490
Deferred income taxes	5	4
Other	70	70
Total deferred debits and other assets	7,165	7,198
Total assets[(a)]	$21,766	$ 21,247

See the Combined Notes to Consolidated Financial Statements
38

Table of Contents

PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2018	December 31, 2017
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities		
Short-term borrowings	$247	$ 350
Long-term debt due within one year	379	396
Accounts payable	514	348
Accrued expenses	220	261
Payables to affiliates	94	90
Borrowings from Exelon intercompany money pool	7	—
Unamortized energy contract liabilities	134	188
Customer deposits	111	119
Merger related obligation	38	42
Regulatory liabilities	125	56
Other	57	81
Total current liabilities	1,926	1,931
Long-term debt	5,737	5,478
Deferred credits and other liabilities		
Regulatory liabilities	1,834	1,872
Deferred income taxes and unamortized investment tax credits	2,146	2,070
Asset retirement obligations	16	16
Non-pension postretirement benefit obligations	100	105
Unamortized energy contract liabilities	504	561
Other	403	389
Total deferred credits and other liabilities	5,003	5,013
Total liabilities[(a)]	12,666	12,422
Commitments and contingencies		
Member's equity		
Membership interest	9,070	8,835
Undistributed earnings (losses)	30	(10)
Total member's equity	9,100	8,825
Total liabilities and member's equity	$21,766	$ 21,247

(a) PHI’s consolidated total assets include $37 million and $41 million at June 30, 2018 and December 31, 2017, respectively, of PHI's consolidated VIE that can only be used to settle the liabilities of the VIE. PHI’s consolidated total liabilities include $88 million and $102 million at June 30, 2018 and December 31, 2017, respectively, of PHI's consolidated VIE for which the VIE creditors do not have recourse to PHI. See Note 3 — Variable Interest Entities for additional information.

See the Combined Notes to Consolidated Financial Statements
39

Table of Contents

PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY
(Unaudited)

(In millions)	Membership Interest	Undistributed Earnings (Losses)	Member's Equity
Balance, December 31, 2017	$ 8,835	$ (10)	$ 8,825
Net income	—	149	149
Distribution to member	—	(109)	(109)
Contribution from member	235	—	235
Balance, June 30, 2018	$ 9,070	$ 30	$ 9,100

See the Combined Notes to Consolidated Financial Statements
40

Table of Contents

POTOMAC ELECTRIC POWER COMPANY
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2018	2017	2018	2017
Operating revenues				
Electric operating revenues	$531	$508	$1,067	$1,022
Revenues from alternative revenue programs	(10)	5	10	20
Operating revenues from affiliates	2	1	3	3
Total operating revenues	523	514	1,080	1,045
Operating expenses				
Purchased power	94	74	224	157
Purchased power from affiliates	46	69	98	152
Operating and maintenance	60	106	133	208
Operating and maintenance from affiliates	56	14	113	26
Depreciation and amortization	92	78	188	160
Taxes other than income	90	90	183	180
Total operating expenses	438	431	939	883
Gain on sales of assets	—	1	—	1
Operating income	85	84	141	163
Other income and (deductions)				
Interest expense, net	(32)	(28)	(63)	(58)
Other, net	8	7	16	15
Total other income and (deductions)	(24)	(21)	(47)	(43)
Income before income taxes	61	63	94	120
Income taxes	7	20	9	19
Net income	$54	$43	$85	$101
Comprehensive income	$54	$43	$85	$101

See the Combined Notes to Consolidated Financial Statements
41

Table of Contents

POTOMAC ELECTRIC POWER COMPANY
STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Six Months Ended June 30, 2018	2017
Cash flows from operating activities		
Net income	$85	$101
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	188	160
Deferred income taxes and amortization of investment tax credits	(8)	35
Gain on sales of long-lived assets	—	(1)
Other non-cash operating activities	24	—
Changes in assets and liabilities:		
Accounts receivable	(31)	(33)
Receivables from and payables to affiliates, net	(11)	(4)
Inventories	2	(10)
Accounts payable and accrued expenses	77	(45)
Income taxes	3	46
Pension and non-pension postretirement benefit contributions	(11)	(65)
Other assets and liabilities	(91)	(55)
Net cash flows provided by operating activities	227	129
Cash flows from investing activities		
Capital expenditures	(287)	(291)
Proceeds from sales of long-lived assets	—	1
Other investing activities	2	(2)
Net cash flows used in investing activities	(285)	(292)
Cash flows from financing activities		
Changes in short-term borrowings	(26)	(23)
Issuance of long-term debt	100	202
Retirement of long-term debt	(7)	(7)
Dividends paid on common stock	(50)	(58)
Contribution from parent	85	161
Other financing activities	(4)	(1)
Net cash flows provided by financing activities	98	274
Increase in cash, cash equivalents and restricted cash	40	111
Cash, cash equivalents and restricted cash at beginning of period	40	42
Cash, cash equivalents and restricted cash at end of period	$80	$153

See the Combined Notes to Consolidated Financial Statements
42

Table of Contents

POTOMAC ELECTRIC POWER COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$ 47	$ 5
Restricted cash and cash equivalents	33	35
Accounts receivable, net		
Customer	272	250
Other	91	87
Inventories, net	85	87
Regulatory assets	248	213
Other	11	33
Total current assets	787	710
Property, plant and equipment, net	6,207	6,001
Deferred debits and other assets		
Regulatory assets	682	678
Investments	105	102
Prepaid pension asset	321	322
Other	21	19
Total deferred debits and other assets	1,129	1,121
Total assets	$ 8,123	$ 7,832

See the Combined Notes to Consolidated Financial Statements

Table of Contents

POTOMAC ELECTRIC POWER COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2018	December 31, 2017
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$—	$ 26
Long-term debt due within one year	20	19
Accounts payable	245	139
Accrued expenses	137	137
Payables to affiliates	63	74
Customer deposits	51	54
Regulatory liabilities	30	3
Merger related obligation	38	42
Current portion of DC PLUG obligation	30	28
Other	10	28
Total current liabilities	624	550
Long-term debt	2,611	2,521
Deferred credits and other liabilities		
Regulatory liabilities	791	829
Deferred income taxes and unamortized investment tax credits	1,101	1,063
Non-pension postretirement benefit obligations	32	36
Other	311	300
Total deferred credits and other liabilities	2,235	2,228
Total liabilities	5,470	5,299
Commitments and contingencies		
Shareholder's equity		
Common stock	1,555	1,470
Retained earnings	1,098	1,063
Total shareholder's equity	2,653	2,533
Total liabilities and shareholder's equity	$ 8,123	$ 7,832

See the Combined Notes to Consolidated Financial Statements
44

Table of Contents

POTOMAC ELECTRIC POWER COMPANY
STATEMENT OF CHANGES IN SHAREHOLDER'S EQUITY
(Unaudited)

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2017	$ 1,470	$ 1,063	$ 2,533
Net income	—	85	85
Common stock dividends	—	(50)	(50)
Contributions from parent	85	—	85
Balance, June 30, 2018	$ 1,555	$ 1,098	$ 2,653

See the Combined Notes to Consolidated Financial Statements
45

Table of Contents

DELMARVA POWER & LIGHT COMPANY
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2018	2017	2018	2017
Operating revenues				
Electric operating revenues	$255	$258	$558	$544
Natural gas operating revenues	28	22	106	87
Revenues from alternative revenue programs	4	—	5	9
Operating revenues from affiliates	2	2	4	4
Total operating revenues	289	282	673	644
Operating expenses				
Purchased power	72	64	162	141
Purchased fuel	12	9	53	38
Purchased power from affiliate	30	40	76	91
Operating and maintenance	36	66	94	133
Operating and maintenance from affiliates	41	8	81	15
Depreciation and amortization	43	40	88	79
Taxes other than income	13	14	28	28
Total operating expenses	247	241	582	525
Operating income	42	41	91	119
Other income and (deductions)				
Interest expense, net	(14)	(13)	(27)	(25)
Other, net	3	3	5	6
Total other income and (deductions)	(11)	(10)	(22)	(19)
Income before income taxes	31	31	69	100
Income taxes	5	12	12	24
Net income	$26	$19	$57	$76
Comprehensive income	$26	$19	$57	$76

See the Combined Notes to Consolidated Financial Statements
46

Table of Contents

DELMARVA POWER & LIGHT COMPANY
STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Six Months Ended June 30, 2018	2017
Cash flows from operating activities		
Net income	$57	$76
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	88	79
Deferred income taxes and amortization of investment tax credits	9	33
Other non-cash operating activities	14	(3)
Changes in assets and liabilities:		
Accounts receivable	18	12
Receivables from and payables to affiliates, net	(22)	(2)
Inventories	4	(3)
Accounts payable and accrued expenses	10	18
Income taxes	16	13
Other assets and liabilities	22	(29)
Net cash flows provided by operating activities	216	194
Cash flows from investing activities		
Capital expenditures	(166)	(192)
Other investing activities	1	1
Net cash flows used in investing activities	(165)	(191)
Cash flows from financing activities		
Changes in short-term borrowings	(216)	25
Issuance of long-term debt	200	—
Retirement of long-term debt	(4)	(14)
Dividends paid on common stock	(40)	(54)
Contribution from parent	150	—
Other financing activities	(2)	—
Net cash flows provided by (used in) financing activities	88	(43)
Increase (Decrease) in cash, cash equivalents and restricted cash	139	(40)
Cash, cash equivalents and restricted cash at beginning of period	2	46
Cash, cash equivalents and restricted cash at end of period	$141	$6

See the Combined Notes to Consolidated Financial Statements
47

Table of Contents

DELMARVA POWER & LIGHT COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$ 141	$ 2
Accounts receivable, net		
Customer	119	146
Other	43	38
Receivables from affiliates	1	—
Inventories, net		
Gas held in storage	5	7
Materials and supplies	34	36
Regulatory assets	64	69
Other	18	27
Total current assets	425	325
Property, plant and equipment, net	3,689	3,579
Deferred debits and other assets		
Regulatory assets	242	245
Goodwill	8	8
Prepaid pension asset	189	193
Other	9	7
Total deferred debits and other assets	448	453
Total assets	$ 4,562	$ 4,357

See the Combined Notes to Consolidated Financial Statements
48

Table of Contents

DELMARVA POWER & LIGHT COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2018	December 31, 2017
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$—	$ 216
Long-term debt due within one year	79	83
Accounts payable	111	82
Accrued expenses	45	35
Payables to affiliates	25	46
Customer deposits	34	35
Regulatory liabilities	67	42
Other	6	8
Total current liabilities	367	547
Long-term debt	1,415	1,217
Deferred credits and other liabilities		
Regulatory liabilities	588	593
Deferred income taxes and unamortized investment tax credits	626	603
Non-pension postretirement benefit obligations	13	14
Other	51	48
Total deferred credits and other liabilities	1,278	1,258
Total liabilities	3,060	3,022
Commitments and contingencies		
Shareholder's equity		
Common stock	914	764
Retained earnings	588	571
Total shareholder's equity	1,502	1,335
Total liabilities and shareholder's equity	$ 4,562	$ 4,357

See the Combined Notes to Consolidated Financial Statements
49

Table of Contents

DELMARVA POWER & LIGHT COMPANY
STATEMENT OF CHANGES IN SHAREHOLDER'S EQUITY
(Unaudited)

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2017	$ 764	$ 571	$ 1,335
Net income	—	57	57
Common stock dividends	—	(40)	(40)
Contribution from parent	150	—	150
Balance, June 30, 2018	$ 914	$ 588	$ 1,502

See the Combined Notes to Consolidated Financial Statements
50

Table of Contents

ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2018	2017	2018	2017
Operating revenues				
Electric operating revenues	$265	$266	$576	$534
Revenues from alternative revenue programs	(1)	3	(3)	9
Operating revenues from affiliates	1	1	2	1
Total operating revenues	265	270	575	544
Operating expenses				
Purchased power	122	121	277	250
Purchased power from affiliates	6	7	12	16
Operating and maintenance	40	71	95	139
Operating and maintenance from affiliates	35	7	70	13
Depreciation and amortization	36	37	69	72
Taxes other than income	1	2	3	4
Total operating expenses	240	245	526	494
Operating income	25	25	49	50
Other income and (deductions)				
Interest expense, net	(16)	(15)	(32)	(30)
Other, net	1	2	1	4
Total other income and (deductions)	(15)	(13)	(31)	(26)
Income before income taxes	10	12	18	24
Income taxes	2	4	3	(12)
Net income	$8	$8	$15	$36
Comprehensive income	$8	$8	$15	$36

See the Combined Notes to Consolidated Financial Statements
51

Table of Contents

ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Six Months Ended June 30, 2018	2017
Cash flows from operating activities		
Net income	$15	$36
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	69	72
Deferred income taxes and amortization of investment tax credits	6	(8)
Other non-cash operating activities	12	7
Changes in assets and liabilities:		
Accounts receivable	(13)	18
Receivables from and payables to affiliates, net	(4)	(6)
Inventories	4	(3)
Accounts payable and accrued expenses	14	3
Income taxes	3	11
Pension and non-pension postretirement benefit contributions	(6)	—
Other assets and liabilities	(33)	(53)
Net cash flows provided by operating activities	67	77
Cash flows from investing activities		
Capital expenditures	(170)	(175)
Other investing activities	(2)	—
Net cash flows used in investing activities	(172)	(175)
Cash flows from financing activities		
Changes in short-term borrowings	14	42
Proceeds from short-term borrowings with maturities greater than 90 days	125	—
Retirement of long-term debt	(15)	(17)
Dividends paid on common stock	(19)	(22)
Other financing activities	—	(1)
Net cash flows provided by financing activities	105	2
Increase (Decrease) in cash, cash equivalents and restricted cash	—	(96)
Cash, cash equivalents and restricted cash at beginning of period	31	133
Cash, cash equivalents and restricted cash at end of period	$31	$37

See the Combined Notes to Consolidated Financial Statements

Table of Contents

ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$ 6	$ 2
Restricted cash and cash equivalents	5	6
Accounts receivable, net		
Customer	103	92
Other	50	56
Inventories, net	25	29
Prepaid utility taxes	36	—
Regulatory assets	60	71
Other	7	2
Total current assets	292	258
Property, plant and equipment, net	2,831	2,706
Deferred debits and other assets		
Regulatory assets	381	359
Long-term note receivable	—	4
Prepaid pension asset	73	73
Other	42	45
Total deferred debits and other assets	496	481
Total assets[a]	$ 3,619	$ 3,445

See the Combined Notes to Consolidated Financial Statements
53

Table of Contents

ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2018	December 31, 2017
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 247	$ 108
Long-term debt due within one year	275	281
Accounts payable	143	118
Accrued expenses	35	33
Payables to affiliates	25	29
Customer deposits	26	31
Regulatory liabilities	29	11
Other	9	8
Total current liabilities	789	619
Long-term debt	832	840
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	501	493
Non-pension postretirement benefit obligations	14	14
Regulatory liabilities	418	411
Other	26	25
Total deferred credits and other liabilities	959	943
Total liabilities[(a)]	2,580	2,402
Commitments and contingencies		
Shareholder's equity		
Common stock	912	912
Retained earnings	127	131
Total shareholder's equity	1,039	1,043
Total liabilities and shareholder's equity	$ 3,619	$ 3,445

(a) ACE’s consolidated total assets include $25 million and $29 million at June 30, 2018 and December 31, 2017, respectively, of ACE's consolidated VIE that can only be used to settle the liabilities of the VIE. ACE’s consolidated total liabilities include $76 million and $90 million at June 30, 2018 and December 31, 2017, respectively, of ACE's consolidated VIE for which the VIE creditors do not have recourse to ACE. See Note 3 — Variable Interest Entities for additional information.

See the Combined Notes to Consolidated Financial Statements

Table of Contents

ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY
CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDER'S EQUITY
(Unaudited)

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2017	$ 912	$ 131	$ 1,043
Net income	—	15	15
Common stock dividends	—	(19)	(19)
Balance, June 30, 2018	$ 912	$ 127	$ 1,039

See the Combined Notes to Consolidated Financial Statements
55

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data, unless otherwise noted)

Index to Combined Notes To Consolidated Financial Statements

The notes to the consolidated financial statements that follow are a combined presentation. The following list indicates the Registrants to which the footnotes apply:

Applicable Notes

Registrant	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
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	.	.	.		.	.			.	.	.	.		.			.	.	.	
Atlantic City Electric Company	.	.	.		.	.			.	.	.	.		.			.	.	.	

56

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

1. Significant Accounting Policies (All Registrants)

Description of Business (All Registrants)

Exelon is a utility services holding company engaged through its principal subsidiaries in the energy generation and energy distribution and transmission businesses.

Name of Registrant	Business	Service Territories
Exelon Generation Company, LLC	Generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity to both wholesale and retail customers. Generation also sells natural gas, renewable energy and other energy-related products and services.	Six reportable segments: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions
Commonwealth Edison Company	Purchase and regulated retail sale of electricity	Northern Illinois, including the City of Chicago
	Transmission and distribution of electricity to retail customers	
PECO Energy Company	Purchase and regulated retail sale of electricity and natural gas	Southeastern Pennsylvania, including the City of Philadelphia (electricity)
	Transmission and distribution of electricity and distribution of natural gas to retail customers	Pennsylvania counties surrounding the City of Philadelphia (natural gas)
Baltimore Gas and Electric Company	Purchase and regulated retail sale of electricity and natural gas	Central Maryland, including the City of Baltimore (electricity and natural gas)
	Transmission and distribution of electricity and distribution of natural gas to retail customers	
Pepco Holdings LLC	Utility services holding company engaged, through its reportable segments Pepco, DPL and ACE	Service Territories of Pepco, DPL and ACE
Potomac Electric Power Company	Purchase and regulated retail sale of electricity	District of Columbia, and major portions of Montgomery and Prince George's Counties, Maryland
	Transmission and distribution of electricity to retail customers	
Delmarva Power & Light Company	Purchase and regulated retail sale of electricity and natural gas	Portions of Delaware and Maryland (electricity)
	Transmission and distribution of electricity and distribution of natural gas to retail customers	Portions of New Castle County, Delaware (natural gas)
	Purchase and regulated retail sale of electricity	

Atlantic City Electric Company	Transmission and distribution of electricity to retail customers	Portions of Southern New Jersey

Basis of Presentation (All Registrants)

Each of the Registrant's Consolidated Financial Statements includes the accounts of its subsidiaries. All intercompany transactions have been eliminated.

The accompanying consolidated financial statements as of June 30, 2018 and 2017 and for the three and six months then ended are unaudited but, in the opinion of the management of each Registrant include all adjustments that are considered necessary for a fair statement of the Registrants' respective financial statements in accordance with GAAP. All adjustments are of a normal, recurring nature, except as otherwise disclosed. The December 31, 2017 revised Consolidated Balance Sheets were derived from audited financial statements. Financial results for interim periods are not necessarily indicative of results that may be expected for any other interim period or for the fiscal year ending December 31, 2018. These Combined Notes to Consolidated Financial Statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to such rules and regulations.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Prior Period Adjustments and Reclassifications (All Registrants)

Certain prior year amounts in the Registrants' Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows, Consolidated Balance Sheets and Consolidated Statements of Changes in Shareholders' Equity have been recasted to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018.

Beginning on January 1, 2018, Exelon adopted the following new accounting standards requiring reclassification or adjustments to previously reported information as follows:

- Statement of Cash Flows: Classification of Restricted Cash. The Registrants applied the new guidance using the full retrospective method and, accordingly, have recasted the presentation of restricted cash in their Consolidated Statements of Cash Flows in the prior periods presented. See Note 18 — Supplemental Financial Information for additional information.
- Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income. Exelon early adopted and retrospectively applied the new guidance to when the effects of the TCJA were recognized and, accordingly, recasted its December 31, 2017 AOCI and retained earnings in its Consolidated Balance Sheet and Consolidated Statement of Changes in Shareholders' Equity. Exelon's accounting policy is to release the stranded tax effects from AOCI related to its pension and OPEB plans under a portfolio (or aggregate) approach as an entire pension or OPEB plan is liquidated or terminated. See Note 2 — New Accounting Standards for additional information.
- Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost. Exelon applied this guidance retrospectively for the presentation of the service and other non-service costs components of net benefit cost and, accordingly, have recasted those amounts, which were not material, in its Consolidated Statement of Operations and Comprehensive Income in prior periods presented. As part of the adoption, Exelon elected the practical expedient that permits an employer to use the amounts disclosed in its pension and other postretirement benefit plan note for the comparative periods as the estimation basis for applying the retrospective presentation requirements. See Note 14 — Retirement Benefits for additional information.
- Revenue from Contracts with Customers. The Registrants applied the new guidance using the full retrospective method and, accordingly, have recasted certain amounts in their Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows, Consolidated Balance Sheets, Consolidated Statements of Changes in Shareholders' Equity and Combined Notes to Consolidated Financial Statements in the prior periods presented. The amounts recasted in the Registrants' Consolidated Statements of Operations and Comprehensive Income are shown in the table below. The amounts recasted in the Registrants’ Consolidated Statements of Cash Flows, Consolidated Balance Sheets, Consolidated Statements of Changes in Shareholders' Equity and Combined Notes to Consolidated Financial Statements were not material. See Note 5 — Revenue from Contracts with Customers for additional information.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Three Months Ended June 30, 2017	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Operating Revenues - As reported									
Competitive business revenues	$3,908	$ —	$—	$—	$—	$—	$—	$—	$—
Rate-regulated utility revenues	3,715	—	—	—	—	—	—	—	—
Operating revenues	—	3,906	—	—	—	—	—	—	—
Electric operating revenues	—	—	1,354	548	569	1,040	513	258	269
Natural gas operating revenues	—	—	—	80	102	22	—	22	—
Operating revenues from affiliates	—	268	3	2	3	12	1	2	1
Total operating revenues	$7,623	$ 4,174	$1,357	$630	$674	$1,074	$514	$282	$270
Operating Revenues - Adjustments									
Competitive business revenues	$42	$ —	$—	$—	$—	$—	$—	$—	$—
Rate-regulated utility revenues	(58)	—	—	—	—	—	—	—	—
Operating revenues	—	42	—	—	—	—	—	—	—
Electric operating revenues	—	—	(18)	—	(24)	(8)	(5)	—	(3)
Natural gas operating revenues	—	—	—	—	(8)	—	—	—	—
Revenues from alternative revenue programs	58	—	18	—	32	8	5	—	3
Operating revenues from affiliates	—	—	—	—	—	—	—	—	—
Total operating revenues	$42	$ 42	$—	$—	$—	$—	$—	$—	$—
Operating Revenues - Retrospective application									
Competitive business revenues	$3,950	$ —	$—	$—	$—	$—	$—	$—	$—
Rate-regulated utility revenues	3,657	—	—	—	—	—	—	—	—
Operating revenues	—	3,948	—	—	—	—	—	—	—
Electric operating revenues	—	—	1,336	548	545	1,032	508	258	266
Natural gas operating revenues	—	—	—	80	94	22	—	22	—
Revenues from alternative revenue programs	58	—	18	—	32	8	5	—	3
Operating revenues from affiliates	—	268	3	2	3	12	1	2	1
Total operating revenues	$7,665	$ 4,216	$1,357	$630	$674	$1,074	$514	$282	$270

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Six Months Ended June 30, 2017	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Operating Revenues - As reported									
Competitive business revenues	$8,468	$ —	$—	$—	$—	$—	$—	$—	$—
Rate-regulated utility revenues	7,913	—	—	—	—	—	—	—	—
Operating revenues	—	8,463	—	—	—	—	—	—	—
Electric operating revenues	—	—	2,647	1,138	1,234	2,138	1,042	553	543
Natural gas operating revenues	—	—	—	285	383	87	—	87	—
Operating revenues from affiliates	—	598	9	3	8	23	3	4	1
Total operating revenues	$16,381	$ 9,061	$2,656	$1,426	$1,625	$2,248	$1,045	$644	$544
Operating Revenues - Adjustments									
Competitive business revenues	$32	$ —	$—	$—	$—	$—	$—	$—	$—
Rate-regulated utility revenues	(137)	—	—	—	—	—	—	—	—
Operating revenues	—	32	—	—	—	—	—	—	—
Electric operating revenues	—	—	(32)	—	(48)	(38)	(20)	(9)	(9)
Natural gas operating revenues	—	—	—	—	(18)	—	—	—	—
Revenues from alternative revenue programs	137	—	32	—	66	38	20	9	9
Operating revenues from affiliates	—	—	—	—	—	—	—	—	—
Total operating revenues	$32	$ 32	$—	$—	$—	$—	$—	$—	$—
Operating Revenues - Retrospective application									
Competitive business revenues	$8,500	$ —	$—	$—	$—	$—	$—	$—	$—
Rate-regulated utility revenues	7,776	—	—	—	—	—	—	—	—
Operating revenues	—	8,495	—	—	—	—	—	—	—
Electric operating revenues	—	—	2,615	1,138	1,186	2,100	1,022	544	534
Natural gas operating revenues	—	—	—	285	365	87	—	87	—
Revenues from alternative revenue programs	137	—	32	—	66	38	20	9	9
Operating revenues from affiliates	—	598	9	3	8	23	3	4	1
Total operating revenues	$16,413	$ 9,093	$2,656	$1,426	$1,625	$2,248	$1,045	$644	$544

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Revenues (All Registrants)

Operating Revenues. The Registrants' operating revenues generally consist of revenues from contracts with customers involving the sale and delivery of energy commodities and related products and services, utility revenues from alternative revenue programs (ARP), and realized and unrealized revenues recognized under mark-to-market energy commodity derivative contracts. The Registrants recognize revenue from contracts with customers to depict the transfer of goods or services to customers in an amount that the entities expect to be entitled to in exchange for those goods or services. Generation's primary sources of revenue include competitive sales of power, natural gas, and other energy-related products and services. The Utility Registrants' primary sources of revenue include regulated electric and natural gas tariff sales, distribution and transmission services. At the end of each month, the Registrants accrue an estimate for the unbilled amount of energy delivered or services provided to customers.

ComEd records ARP revenue for its best estimate of the electric distribution, energy efficiency, and transmission revenue impacts resulting from future changes in rates that ComEd believes are probable of approval by the ICC and FERC in accordance with its formula rate mechanisms. BGE, Pepco and DPL record ARP revenue for their best estimate of the electric and natural gas distribution revenue impacts resulting from future changes in rates that they believe are probable of approval by the MDPSC and/or DCPSC in accordance with their revenue decoupling mechanisms. PECO, BGE, Pepco, DPL and ACE record ARP revenue for their best estimate of the transmission revenue impacts resulting from future changes in rates that they believe are probable of approval by FERC in accordance with their formula rate mechanisms. See Note 5 — Revenue from Contracts with Customers and Note 6 —Regulatory Matters for additional information.

RTOs and ISOs. In RTO and ISO markets that facilitate the dispatch of energy and energy-related products, the Registrants generally report sales and purchases conducted on a net hourly basis in either revenues or purchased power on their Consolidated Statements of Operations and Comprehensive Income, the classification of which depends on the net hourly sale or purchase position. In addition, capacity revenue and expense classification is based on the net sale or purchase position of the Registrants in the different RTOs and ISOs.

Option Contracts, Swaps and Commodity Derivatives. Certain option contracts and swap arrangements that meet the definition of derivative instruments are recorded at fair value with subsequent changes in fair value recognized as revenue or expense. The classification of revenue or expense is based on the intent of the transaction. For example, gas transactions may be used to hedge the sale of power. This will result in the change in fair value recorded through revenue. To the extent a Utility Registrant receives full cost recovery for energy procurement and related costs from retail customers, it records the fair value of its energy swap contracts with unaffiliated suppliers as well as an offsetting regulatory asset or liability on its Consolidated Balance Sheets. See Note 6 — Regulatory Matters and Note 10 — Derivative Financial Instruments for additional information.

Taxes Directly Imposed on Revenue-Producing Transactions. The Registrants collect certain taxes from customers such as sales and gross receipts taxes, along with other taxes, surcharges and fees that are levied by state or local governments on the sale or distribution of natural gas and electricity. Some of these taxes are imposed on the customer, but paid by the Registrants, while others are imposed directly on the Registrants. The Registrants do not recognize revenue or expense in their Consolidated Statements of Operations and Comprehensive Income when these taxes are imposed on the customer, such as sales taxes. However, when these taxes are imposed directly on the Registrants, such as gross receipts taxes or other surcharges or fees, the Registrants recognize revenue for the taxes collected from customers along with an offsetting expense. See Note 18 — Supplemental Financial Information for Generation's, ComEd's, PECO's, BGE's, Pepco's, DPL's and ACE's utility taxes that are presented on a gross basis.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

2. New Accounting Standards (All Registrants)

New Accounting Standards Adopted: In 2018, the Registrants have adopted the following new authoritative accounting guidance issued by the FASB.

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income (Issued February 2018): Provides an election for a reclassification from AOCI to Retained earnings to eliminate the stranded tax effects resulting from the TCJA. This standard is effective January 1, 2019, with early adoption permitted, and may be applied either in the period of adoption or retrospective to each period in which the effects of the TCJA were recognized. Exelon early adopted this standard during the first quarter 2018 and elected to apply the guidance retrospectively as of December 31, 2017, which resulted in an increase to Exelon’s Retained earnings and Accumulated other comprehensive loss of $539 million related to deferred income taxes associated with Exelon’s pension and OPEB obligations. There was no impact for Generation, ComEd, PECO, BGE, PHI, Pepco, DPL or ACE.

See Note 1 — Significant Accounting Policies of the Exelon 2017 Form 10-K for information on other new accounting standards issued and adopted as of January 1, 2018.

New Accounting Standards Issued and Not Yet Adopted as of June 30, 2018: The following new authoritative accounting guidance issued by the FASB has not yet been adopted and reflected by the Registrants in their consolidated financial statements as of June 30, 2018. Unless otherwise indicated, the Registrants are currently assessing the impacts such guidance may have (which could be material) on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures, as well as the potential to early adopt where applicable. The Registrants have assessed other FASB issuances of new standards which are not listed below given the current expectation that such standards will not significantly impact the Registrants' financial reporting.

Leases (Issued February 2016): Increases transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The standard is effective January 1, 2019. Early adoption is permitted; however, the Registrants will not early adopt the standard. The issued guidance required a modified retrospective transition approach, which requires lessees and lessors to recognize and measure leases at the beginning of the earliest period presented (January 1, 2017). In July 2018, the FASB issued an amendment to the standard giving entities the option to apply the requirements of the standard in the period of adoption (January 1, 2019) with no restatement of prior periods. Exelon plans to elect this expedient.

The new guidance requires lessees to recognize both the right-of-use assets and lease liabilities in the balance sheet for most leases, whereas today only finance lease liabilities (referred to as capital leases) are recognized in the balance sheet. In addition, the definition of a lease has been revised which may result in changes to the classification of an arrangement as a lease. Under the new guidance, an arrangement that conveys the right to control the use of an identified asset by obtaining substantially all of its economic benefits and directing how it is used is a lease, whereas the current definition focuses on the ability to control the use of the asset or to obtain its output. Quantitative and qualitative disclosures related to the amount, timing and judgments of an entity’s accounting for leases and the related cash flows are expanded. Disclosure requirements apply to both lessees and lessors, whereas current disclosures relate only to lessees. Significant changes to lease systems, processes and procedures are required to implement the requirements of the new standard. The recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee have not significantly changed from current GAAP. Lessor accounting is also largely unchanged.

The standard provides a number of transition practical expedients that entities may elect. These include a "package of three" expedients that must be taken together and allow entities to (1) not reassess

Table of Contents

whether existing contracts contain leases, (2) carryforward the existing lease classification, and (3) not reassess initial direct costs associated with existing leases. The Registrants expect to elect this practical expedient.

In January 2018, the FASB issued additional guidance which provides another optional transition practical expedient. This practical expedient allows entities to not evaluate land easements under the new guidance at adoption if they were not previously accounted for as leases.

The Registrants have assessed the lease standard and are executing a detailed implementation plan in preparation for adoption on January 1, 2019. Key activities in the implementation plan include:

- Developing a complete lease inventory and abstracting the required data attributes into a lease accounting system that supports the Registrants' lease portfolios and integrates with existing systems.
- Evaluating the transition practical expedients available under the guidance.
- Identifying, assessing and documenting technical accounting issues, policy considerations and financial reporting implications.
- Identifying and implementing changes to processes and controls to ensure all impacts of the new guidance are effectively addressed.

Impairment of Financial Instruments (Issued June 2016): Provides for a new Current Expected Credit Loss (CECL) impairment model for specified financial instruments including loans, trade receivables, debt securities classified as held-to-maturity investments and net investments in leases recognized by a lessor. Under the new guidance, on initial recognition and at each reporting period, an entity is required to recognize an allowance that reflects the entity’s current estimate of credit losses expected to be incurred over the life of the financial instrument. The standard does not make changes to the existing impairment models for non-financial assets such as fixed assets, intangibles and goodwill. The standard will be effective January 1, 2020 (with early adoption as of January 1, 2019 permitted) and requires a modified retrospective transition approach through a cumulative-effect adjustment to retained earnings as of the beginning of the period of adoption.

Goodwill Impairment (Issued January 2017): Simplifies the accounting for goodwill impairment by removing Step 2 of the current test, which requires calculation of a hypothetical purchase price allocation. Under the revised guidance, goodwill impairment will be measured as the amount by which a reporting unit’s carrying value exceeds its fair value, not to exceed the carrying amount of goodwill (currently Step 1 of the two-step impairment test). Entities will continue to have the option to perform a qualitative assessment to determine if a quantitative impairment test is necessary. Exelon, Generation, ComEd, PHI and DPL have goodwill as of June 30, 2018. This updated guidance is not currently expected to impact the Registrants’ financial reporting. The standard is effective January 1, 2020, with early adoption permitted, and must be applied on a prospective basis.

Derivatives and Hedging (Issued September 2017): Allows more financial and nonfinancial hedging strategies to be eligible for hedge accounting. The amendments are intended to more closely align hedge accounting with companies’ risk management strategies, simplify the application of hedge accounting, and increase transparency as to the scope and results of hedging programs. There are also amendments related to effectiveness testing and disclosure requirements. The guidance is effective January 1, 2019 and early adoption is permitted with a modified retrospective transition approach. The Registrants are currently assessing this standard but do not currently expect a significant impact given the limited activity for which the Registrants elect hedge accounting and because the Registrants do not anticipate increasing their use of hedge accounting as a result of this standard.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

3. Variable Interest Entities (All Registrants)

A VIE is a legal entity that possesses any of the following characteristics: an insufficient amount of equity at risk to finance its activities, equity owners who do not have the power to direct the significant activities of the entity (or have voting rights that are disproportionate to their ownership interest) or equity owners who do not have the obligation to absorb expected losses or the right to receive the expected residual returns of the entity. Companies are required to consolidate a VIE if they are its primary beneficiary, which is the enterprise that has the power to direct the activities that most significantly affect the entity's economic performance.

At June 30, 2018 and December 31, 2017, Exelon, Generation, PHI and ACE collectively consolidated five VIEs or VIE groups for which the applicable Registrant was the primary beneficiary (see Consolidated Variable Interest Entities below). As of June 30, 2018 and December 31, 2017, Exelon and Generation collectively had significant interests in seven other VIEs for which the applicable Registrant does not have the power to direct the entities' activities and, accordingly, was not the primary beneficiary (see Unconsolidated Variable Interest Entities below).

Consolidated Variable Interest Entities

As of June 30, 2018 and December 31, 2017, Exelon's and Generation's consolidated VIEs consist of:

- energy related companies involved in distributed generation, backup generation and energy development
- renewable energy project companies formed by Generation to build, own and operate renewable power facilities
- certain retail power and gas companies for which Generation is the sole supplier of energy, and
- CENG.

As of June 30, 2018 and December 31, 2017, Exelon's, PHI's and ACE's consolidated VIE consist of:

- ATF, a special purpose entity formed by ACE for the purpose of securitizing authorized portions of ACE's recoverable stranded costs through the issuance and sale of transition bonds.

As of June 30, 2018 and December 31, 2017, ComEd, PECO, BGE, Pepco and DPL did not have any material consolidated VIEs.

As of June 30, 2018 and December 31, 2017, Exelon and Generation provided the following support to their respective consolidated VIEs:

- Generation provides operating and capital funding to the renewable energy project companies and there is limited recourse to Generation related to certain renewable energy project companies.
- Generation provides operating and capital funding to one of the energy related companies involved in backup generation.
- Generation provides approximately $34 million in credit support for the retail power and gas companies for which Generation is the sole supplier of energy.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

- Exelon and Generation, where indicated, provide the following support to CENG (see Note 26 — Related Party Transactions of the Exelon 2017 Form 10-K for additional information regarding Generation's and Exelon’s transactions with CENG):
- under power purchase agreements with CENG, Generation purchased or will purchase 50.01% of the available output generated by the CENG nuclear plants not subject to other contractual agreements from January 2015 through the end of the operating life of each respective plant. However, pursuant to amendments dated March 31, 2015, the energy obligations under the Ginna Nuclear Power Plant (Ginna) PPAs were suspended during the term of the Reliability Support Services Agreement (RSSA), through the end of March 31, 2017. With the expiration of the RSSA, the PPA was reinstated beginning April 1, 2017,
- Generation provided a $400 million loan to CENG. As of June 30, 2018, the remaining obligation is $191 million,
- Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF against third-party claims that may arise from any future nuclear incident (as defined in the Price-Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation’s obligations under this Indemnity Agreement. (See Note 17 — Commitments and Contingencies for additional information),
- Generation and EDF share in the $637 million of contingent payment obligations for the payment of contingent retrospective premium adjustments for the nuclear liability insurance,
- Exelon has executed an agreement to provide up to $245 million to support the operations of CENG as well as a $165 million guarantee of CENG’s cash pooling agreement with its subsidiaries.

As of June 30, 2018 and December 31, 2017, Exelon, PHI and ACE provided the following support to their respective consolidated VIE:

- In the case of ATF, proceeds from the sale of each series of transition bonds by ATF were transferred to ACE in exchange for the transfer by ACE to ATF of the right to collect a non-bypassable Transition Bond Charge from ACE customers pursuant to bondable stranded costs rate orders issued by the NJBPU in an amount sufficient to fund the principal and interest payments on transition bonds and related taxes, expenses and fees. During the three and six months ended June 30, 2018, ACE transferred $6 million and $14 million to ATF, respectively. During the three and six months ended June 30, 2017, ACE transferred $8 million and $27 million to ATF, respectively.

For each of the consolidated VIEs, except as otherwise noted:

- the assets of the VIEs are restricted and can only be used to settle obligations of the respective VIE;
- Exelon, Generation, PHI and ACE did not provide any additional material financial support to the VIEs;
- Exelon, Generation, PHI and ACE did not have any material contractual commitments or obligations to provide financial support to the VIEs; and

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

• the creditors of the VIEs did not have recourse to Exelon's, Generation's, PHI's or ACE's general credit.

The carrying amounts and classification of the consolidated VIEs' assets and liabilities included in the Registrants' consolidated financial statements at June 30, 2018 and December 31, 2017 are as follows:

	June 30, 2018				December 31, 2017			
	Exelon[a]	Generation	PHI[a]	ACE	Exelon[a]	Generation	PHI[a]	ACE
Current assets	$744	$ 735	$ 9	$ 5	$662	$ 652	$ 10	$ 6
Noncurrent assets	9,234	9,206	28	20	9,317	9,286	31	23
Total assets	$9,978	$ 9,941	$ 37	$ 25	$9,979	$ 9,938	$ 41	$ 29
Current liabilities	$268	$ 238	$ 30	$ 26	$308	$ 272	$ 36	$ 32
Noncurrent liabilities	3,284	3,226	58	50	3,316	3,250	66	58
Total liabilities	$3,552	$ 3,464	$ 88	$ 76	$3,624	$ 3,522	$ 102	$ 90

(a) Includes certain purchase accounting adjustments not pushed down to the ACE standalone entity.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Assets and Liabilities of Consolidated VIEs

Included within the balances above are assets and liabilities of certain consolidated VIEs for which the assets can only be used to settle obligations of those VIEs, and liabilities that creditors or beneficiaries do not have recourse to the general credit of the Registrants. As of June 30, 2018 and December 31, 2017, these assets and liabilities primarily consisted of the following:

	June 30, 2018				December 31, 2017			
	Exelon (a)	Generation	PHI (a)	ACE	Exelon (a)	Generation	PHI (a)	ACE
Cash and cash equivalents	$205	$ 205	$—	$ —	$126	$ 126	$ —	$ —
Restricted cash	77	72	5	5	64	58	6	6
Accounts receivable, net								
Customer	149	149	—	—	170	170	—	—
Other	32	32	—	—	25	25	—	—
Inventory, net								
Materials and supplies	208	208	—	—	205	205	—	—
Other current assets	47	43	4	—	45	41	4	—
Total current assets	718	709	9	5	635	625	10	6
Property, plant and equipment, net	6,157	6,157	—	—	6,186	6,186	—	—
Nuclear decommissioning trust funds	2,483	2,483	—	—	2,502	2,502	—	—
Other noncurrent assets	254	226	28	20	274	243	31	23
Total noncurrent assets	8,894	8,866	28	20	8,962	8,931	31	23
Total assets	$9,612	$ 9,575	$37	$ 25	$9,597	$ 9,556	$ 41	$ 29
Long-term debt due within one year	$95	$ 66	$29	$ 25	$102	$ 67	$ 35	$ 31
Accounts payable	74	74	—	—	114	114	—	—
Accrued expenses	81	80	1	1	67	66	1	1
Unamortized energy contract liabilities	16	16	—	—	18	18	—	—
Other current liabilities	2	2	—	—	7	7	—	—
Total current liabilities	268	238	30	26	308	272	36	32
Long-term debt	1,119	1,061	58	50	1,154	1,088	66	58
Asset retirement obligations	2,088	2,088	—	—	2,035	2,035	—	—
Other noncurrent liabilities	69	69	—	—	121	121	—	—
Total noncurrent liabilities	3,276	3,218	58	50	3,310	3,244	66	58
Total liabilities	$3,544	$ 3,456	$88	$ 76	$3,618	$ 3,516	$ 102	$ 90

(a) Includes certain purchase accounting adjustments not pushed down to the ACE standalone entity.

Unconsolidated Variable Interest Entities

Exelon’s and Generation’s variable interests in unconsolidated VIEs generally include equity investments and energy purchase and sale contracts. For the equity investments, the carrying amount of the investments is reflected on Exelon’s and Generation’s Consolidated Balance Sheets in Investments. For the energy purchase and sale contracts (commercial agreements), the carrying amount of assets and liabilities in Exelon’s and Generation’s Consolidated Balance Sheets that relate to their involvement with the VIEs are predominately related to working capital accounts and generally represent the amounts owed by, or owed to, Exelon and Generation for the deliveries associated with the current billing cycles under the commercial agreements. Further, Exelon and Generation have not provided

Table of Contents

material debt or equity support, liquidity arrangements or performance guarantees associated with these commercial agreements.

As of June 30, 2018 and December 31, 2017, Exelon's and Generation's unconsolidated VIEs consist of:

- Energy purchase and sale agreements with VIEs for which Generation has concluded that consolidation is not required.
- Asset sale agreement with ZionSolutions, LLC and EnergySolutions, Inc. in which Generation has a variable interest but has concluded that consolidation is not required.
- Equity investments in distributed energy companies for which Generation has concluded that consolidation is not required.

As of June 30, 2018 and December 31, 2017, ComEd, PECO, BGE, PHI, Pepco, ACE and DPL did not have any material unconsolidated VIEs.

As of June 30, 2018 and December 31, 2017, Exelon and Generation had significant unconsolidated variable interests in seven VIEs for which Exelon or Generation, as applicable, was not the primary beneficiary; including certain equity investments and certain commercial agreements. Exelon and Generation only include unconsolidated VIEs that are individually material in the tables below. However, Generation has several individually immaterial VIEs that in aggregate represent a total investment of $9 million. These immaterial VIEs are equity and debt securities in energy development companies. The maximum exposure to loss related to these securities is limited to the $9 million included in Investments on Exelon’s and Generation’s Consolidated Balance Sheets. The risk of a loss was assessed to be remote and, accordingly, Exelon and Generation have not recognized a liability associated with any portion of the maximum exposure to loss.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

The following tables present summary information about Exelon's and Generation's significant unconsolidated VIE entities:

June 30, 2018	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[(a)]	$ 620	$ 491	$1,111
Total liabilities[(a)]	37	224	261
Exelon's ownership interest in VIE[(a)]	—	238	238
Other ownership interests in VIE[(a)]	583	29	612
Registrants' maximum exposure to loss:			
Carrying amount of equity method investments	—	238	238
Contract intangible asset	8	—	8
Net assets pledged for Zion Station decommissioning[(b)]	1	—	1

December 31, 2017	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[(a)]	$ 625	$ 509	$1,134
Total liabilities[(a)]	37	228	265
Exelon's ownership interest in VIE[(a)]	—	251	251
Other ownership interests in VIE[(a)]	588	30	618
Registrants' maximum exposure to loss:			
Carrying amount of equity method investments	—	251	251
Contract intangible asset	8	—	8
Net assets pledged for Zion Station decommissioning[(b)]	2	—	2

(a) These items represent amounts on the unconsolidated VIE balance sheets, not on Exelon's or Generation's Consolidated Balance Sheets. These items are included to provide information regarding the relative size of the unconsolidated VIEs.

(b) These items represent amounts on Exelon's and Generation's Consolidated Balance Sheets related to the asset sale agreement with ZionSolutions, LLC. The net assets pledged for Zion Station decommissioning includes gross pledged assets of $21 million and $39 million as of June 30, 2018 and December 31, 2017, respectively; offset by payables to ZionSolutions, LLC of $20 million and $37 million as of June 30, 2018 and December 31, 2017, respectively. These items are included to provide information regarding the relative size of the ZionSolutions, LLC unconsolidated VIE. See Note 13 — Nuclear Decommissioning for additional information.

For each of the unconsolidated VIEs, Exelon and Generation have assessed the risk of a loss equal to their maximum exposure to be remote and, accordingly, Exelon and Generation have not recognized a liability associated with any portion of the maximum exposure to loss. In addition, there are no material agreements with, or commitments by, third parties that would affect the fair value or risk of their variable interests in these VIEs.

4. Mergers, Acquisitions and Dispositions (Exelon and Generation)

Acquisition of Handley Generating Station

On November 7, 2017, EGTP and all of its wholly owned subsidiaries filed voluntary petitions for relief under Chapter 11 of Title 11 of the United States Code in the United States Bankruptcy Court for the District of Delaware, which resulted in Exelon and Generation deconsolidating EGTP's assets and liabilities from their consolidated financial statements in the fourth quarter of 2017. Concurrently with the

Table of Contents

Chapter 11 filings, Generation entered into an asset purchase agreement to acquire one of EGTP's generating plants, the Handley Generating Station, subject to a potential adjustment for fuel oil and assumption of certain liabilities. In the Chapter 11 Filings, EGTP requested that the proposed acquisition of the Handley Generating Station be consummated through a court-approved and supervised sales process. The acquisition was approved by the Bankruptcy Court in January 2018 and closed on April 4, 2018 for a purchase price of $62 million. The Chapter 11 bankruptcy proceedings were finalized on April 17, 2018, resulting in the ownership of EGTP assets (other than the Handley Generating Station) being transferred to EGTP's lenders.

Acquisition of James A. FitzPatrick Nuclear Generating Station

On March 31, 2017, Generation acquired the 842 MW single-unit James A. FitzPatrick (FitzPatrick) nuclear generating station located in Scriba, New York from Entergy Nuclear FitzPatrick LLC (Entergy) for a total purchase price of $289 million, which consisted of a cash purchase price of $110 million and a net cost reimbursement to and on behalf of Entergy of $179 million. As part of the acquisition agreements, Generation provided nuclear fuel and reimbursed Entergy for incremental costs to prepare for and conduct a plant refueling outage; and Generation reimbursed Entergy for incremental costs to operate and maintain the plant for the period after the refueling outage through the acquisition closing date. These reimbursements covered costs that Entergy otherwise would have avoided had it shut down the plant as originally intended in January 2017. The amounts reimbursed by Generation were offset by FitzPatrick's electricity and capacity sales revenues for this same post-outage period. As part of the transaction, Generation received the FitzPatrick NDT fund assets and assumed the obligation to decommission FitzPatrick. The NRC license for FitzPatrick expires in 2034.

The fair values of FitzPatrick’s assets and liabilities were determined based on significant estimates and assumptions that are judgmental in nature, including projected future cash flows (including timing), discount rates reflecting risk inherent in the future cash flows and future power and fuel market prices. The valuations performed in the first quarter of 2017 to determine the fair value of the FitzPatrick assets acquired and liabilities assumed were updated in the third quarter of 2017. The purchase price allocation is now final.

For the three months ended March 31, 2017, an after-tax bargain purchase gain of $226 million is included within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income and primarily reflects differences in strategies between Generation and Entergy for the intended use and ultimate decommissioning of the plant. During the third quarter of 2017, Exelon and Generation recorded an additional after-tax bargain purchase gain of $7 million for the three months ended September 30, 2017. The total after tax bargain purchase gain recorded at Exelon and Generation was $233 million for the twelve months ended December 31, 2017. See Note 13 — Nuclear Decommissioning and Note 14 — Retirement Benefits for additional information regarding the FitzPatrick decommissioning ARO and pension and OPEB updates.

(Dollars in millions, except per share data, unless otherwise noted)

Table of Contents

The following table summarizes the acquisition-date fair value of the consideration transferred and the assets and liabilities assumed for the FitzPatrick acquisition by Generation:

Cash paid for purchase price	$110
Cash paid for net cost reimbursement	125
Nuclear fuel transfer	54
Total consideration transferred	$289
Identifiable assets acquired and liabilities assumed	
Current assets	$60
Property, plant and equipment	298
Nuclear decommissioning trust funds	807
Other assets[(a)]	114
Total assets	$1,279
Current liabilities	$6
Nuclear decommissioning ARO	444
Pension and OPEB obligations	33
Deferred income taxes	149
Spent nuclear fuel obligation	110
Other liabilities	15
Total liabilities	$757
Total net identifiable assets, at fair value	$522
Bargain purchase gain (after tax)	$233

(a) Includes a $110 million asset associated with a contractual right to reimbursement from the New York Power Authority (NYPA), a prior owner of FitzPatrick, associated with the DOE one-time fee obligation. See Note 23-Commitments and Contingencies of the Exelon 2017 Form 10-K for additional information regarding SNF obligations to the DOE.

Exelon and Generation incurred $16 million and $47 million of merger and integration costs related to FitzPatrick for the three and six months ended June 30, 2017, respectively, which are included within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. Exelon and Generation did not incur any merger and integration costs related to FitzPatrick for the three and six months ended June 30, 2018.

Asset Disposition

In December 2017, Generation entered into an agreement to sell its interest in an electrical contracting business that primarily installs, maintains and repairs underground and high-voltage cable transmission and distribution systems. As a result, as of December 31, 2017, certain assets and liabilities were classified as held for sale and included in the Other current assets and Other current liabilities balances on Exelon's and Generation's Consolidated Balance Sheet. On February 28, 2018, Generation completed the sale of its interest for $87 million, resulting in a pre-tax gain which is included within Gain on sales of assets and businesses on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. In June 2018, additional proceeds were received, and a pre-tax gain was recorded within Gain on sales of assets and businesses on Exelon's and Generation's Consolidated Statement of Operations and Comprehensive Income.

Table of Contents

5. Revenue from Contracts with Customers (All Registrants)

The Registrants recognize revenue from contracts with customers to depict the transfer of goods or services to customers at an amount that the entities expect to be entitled to in exchange for those goods or services. Generation's primary sources of revenue include competitive sales of power, natural gas, and other energy-related products and services. The Utility Registrants' primary sources of revenue include regulated electric and gas tariff sales, distribution and transmission services. The performance obligations associated with these sources of revenue are further discussed below.

Unless otherwise noted, for each of the significant revenue categories and related performance obligations described below, the Registrants have the right to consideration from the customer in an amount that corresponds directly with the value transferred to the customer for the performance completed to date. Therefore, the Registrant's have elected to use the right to invoice practical expedient for the contracts within these revenue categories and generally recognize revenue in the amount for which they have the right to invoice the customer. As a result, there are generally no significant judgments used in determining or allocating the transaction price.

Competitive Power Sales (Exelon and Generation)

Generation sells power and other energy-related commodities to both wholesale and retail customers across multiple geographic regions through its customer-facing business, Constellation. Power sale contracts generally contain various performance obligations including the delivery of power and other energy-related commodities such as capacity, ZECs, RECs or other ancillary services. Revenues related to such contracts are generally recognized over time as the power is generated and simultaneously delivered to the customer. However, revenues related to the sale of any goods or services that are not simultaneously received and consumed by the customer are recognized as the performance obligations are satisfied at a point in time. Payment terms generally require that the customers pay for the power or the energy-related commodity within the month following delivery to the customer and there are generally no significant financing components.

Certain contracts may contain limits on the total amount of revenue we are able to collect over the entire term of the contract. In such cases, the Registrants estimate the total consideration expected to be received over the term of the contract net of the constraint and allocate the expected consideration to the performance obligations in the contract such that revenue is recognized ratably over the term of the entire contract as the performance obligations are satisfied.

Competitive Natural Gas Sales (Exelon and Generation)

Generation sells natural gas on a full requirements basis or for an agreed upon volume to both commercial and residential customers. The primary performance obligation associated with natural gas sale contracts is the delivery of the natural gas to the customer. Revenues related to the sale of natural gas are recognized over time as the natural gas is delivered to and consumed by the customer. Payment from customers is typically due within the month following delivery of the natural gas to the customer and there are generally no significant financing components.

Other Competitive Products and Services (Exelon and Generation)

Generation also sells other energy-related products and services such as long-term construction and installation of energy efficiency assets and new power generating facilities, primarily to commercial and industrial customers. These contracts generally contain a single performance obligation, which is the construction and/or installation of the asset for the customer. The average contract term for these projects is approximately 18 months. Revenues, and associated costs, are recognized throughout the contract term using an input method to measure progress towards completion. The method recognizes revenue based on the various inputs used to satisfy the performance obligation, such as costs incurred

Table of Contents

and total labor hours expended. The total amount of revenue that will be recognized is based on the agreed upon contractually-stated amount. Payments from customers are typically due within 30 or 45 days from the date the invoice is generated and sent to the customer.

Regulated Electric and Gas Tariff Sales (Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE)

The Utility Registrants sell electricity and electricity distribution services to residential, commercial, industrial and governmental customers through regulated tariff rates approved by their state regulatory commissions. PECO, BGE and DPL also sell natural gas and gas distribution services to residential, commercial, and industrial customers through regulated tariff rates approved by their state regulatory commissions. The performance obligation associated with these tariff sale contracts is the delivery of electricity and/or natural gas. Tariff sales are generally considered daily contracts given that customers can discontinue service at any time. Revenues are generally recognized over time (each day) as the electricity and/or natural gas is delivered to customers. Payment terms generally require that customers pay for the services within the month following delivery of the electricity or natural gas to the customer and there are generally no significant financing components or variable consideration.

Electric and natural gas utility customers have the choice to purchase electricity or natural gas from competitive electric generation and natural gas suppliers. While the Utility Registrants are required under state legislation to bill their customers for the supply and distribution of electricity and/or natural gas, they recognize revenue related only to the distribution services when customers purchase their electricity or natural gas from competitive suppliers.

Regulated Transmission Services (Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE)

Under FERC’s open access transmission policy, the Utility Registrants, as owners of transmission facilities, are required to provide open access to their transmission facilities under filed tariffs at cost-based rates approved by FERC. The Utility Registrants are members of PJM, the regional transmission organization designated by FERC to coordinate the movement of wholesale electricity in PJM’s region, which includes portions of the mid-Atlantic and Midwest. In accordance with FERC-approved rules, the Utility Registrants and other transmission owners in the PJM region make their transmission facilities available to PJM, which directs and controls the operation of these transmission facilities and accordingly compensates the Utility Registrants and other transmission owners. The performance obligations associated with the Utility Registrants’ contract with PJM include (i) Network Integration Transmission Services (NITS), (ii) scheduling, system control and dispatch services, and (iii) access to the wholesale grid. These performance obligations are satisfied over time, and Utility Registrants utilize output methods to measure the progress towards their completion. Passage of time is used for NITS and access to the wholesale grid and MWhs of energy transported over the wholesale grid is used for scheduling, system control and dispatch services. PJM pays the Utility Registrants for these services on a weekly basis and there are no financing components or variable consideration.

Costs to Obtain or Fulfill a Contract with a Customer (Exelon and Generation)

Generation incurs incremental costs in order to execute certain retail power and gas sales contracts. These costs primarily relate to retail broker fees and sales commissions. Generation has capitalized such contract acquisition costs in the amount of $28 million and $26 million as of June 30, 2018 and December 31, 2017, respectively, within Other current assets and Other deferred debits in Exelon’s and Generation’s Consolidated Balance Sheets. These costs are capitalized when incurred and amortized using the straight-line method over the average length of such retail contracts, which is approximately 2 years. Exelon and Generation recognized amortization expense associated with these costs in the amount of $5 million and $11 million for the three and six months ended June 30, 2018, respectively, and $8 million and $17 million for the three and six months ended June 30, 2017, respectively, within Operating and maintenance expense in Exelon’s and Generation’s Consolidated Statements of Operations and Comprehensive Income. Generation does not incur material costs to fulfill contracts

(Dollars in millions, except per share data, unless otherwise noted)

Table of Contents

with customers that are not already capitalized under existing guidance. In addition, the Utility Registrants do not incur any material costs to obtain or fulfill contracts with customers.

Contract Balances (All Registrants)

Contract Assets

Generation records contract assets for the revenue recognized on the construction and installation of energy efficiency assets and new power generating facilities before Generation has an unconditional right to bill for and receive the consideration from the customer. These contract assets are subsequently reclassified to receivables when the right to payment becomes unconditional. Generation records contract assets and contract receivables within Other current assets and Accounts receivable, net - Customer, respectively, within Exelon’s and Generation’s Consolidated Balance Sheets. The following table provides a rollforward of the contract assets reflected on Exelon's and Generation's Consolidated Balance Sheets from January 1, 2018 to June 30, 2018:

Contract Assets	Exelon and Generation
Balance as of January 1, 2018	$ 283
Increases as a result of changes in the estimate of the stage of completion	28
Amounts reclassified to receivables	(68)
Balance at June 30, 2018	$ 243

The Utility Registrants do not have any contract assets.

Contract Liabilities

Generation records contract liabilities when consideration is received or due prior to the satisfaction of the performance obligations. These contract liabilities primarily relate to upfront consideration received or due for equipment service plans, solar panel leases and the Illinois ZEC program that introduces a cap on the total consideration to be received by Generation. Generation records contract liabilities within Other current liabilities and Other noncurrent liabilities within Exelon’s and Generation’s Consolidated Balance Sheets. The following table provides a rollforward of the contract liabilities reflected on Exelon's and Generation's Consolidated Balance Sheet from January 1, 2018 to June 30, 2018:

Contract Liabilities	Exelon and Generation
Balance as of January 1, 2018	$ 35
Increases as a result of additional cash received or due	298
Amounts recognized into revenues	(305)
Balance at June 30, 2018	$ 28

The Utility Registrants also record contract liabilities when consideration is received prior to the satisfaction of the performance obligations. As of June 30, 2018 and December 31, 2017, the Utility Registrants' contract liabilities were immaterial.

Transaction Price Allocated to Remaining Performance Obligations (All Registrants)

The following table shows the amounts of future revenues expected to be recorded in each year for performance obligations that are unsatisfied or partially unsatisfied as of June 30, 2018. Generation has elected the exemption which permits the exclusion from this disclosure of certain variable contract consideration. As such, the majority of Generation’s power and gas sales contracts are excluded from this disclosure as they contain variable volumes and/or variable pricing. Thus, this disclosure only includes contracts for which the total consideration is fixed and determinable at contract inception. The average contract term varies by customer type and commodity but ranges from one month to several years.

(Dollars in millions, except per share data, unless otherwise noted)

The majority of the Utility Registrants' tariff sale contracts are generally day-to-day contracts and, therefore, do not contain any future, unsatisfied performance obligations to be included in this disclosure. Further, the Utility Registrants have elected the exemption to not disclose the transaction price allocation to remaining performance obligations for contracts with an original expected duration of one year or less. As such, gas and electric tariff sales contracts and transmission revenue contracts are excluded from this disclosure.

	2019	2020	2021	2022	2023 and thereafter	Total
Exelon	$574	$279	$113	$ 46	$ 128	$1,140
Generation	574	279	113	46	128	$1,140

Revenue Disaggregation (All Registrants)

The Registrants disaggregate revenue recognized from contracts with customers into categories that depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors. See Note 19 — Segment Information for the presentation of the Registrant's revenue disaggregation.

6. Regulatory Matters (All Registrants)

Except for the matters noted below, the disclosures set forth in Note 3 — Regulatory Matters of the Exelon 2017 Form 10-K reflect, in all material respects, the current status of regulatory and legislative proceedings of the Registrants. The following is an update to that discussion.

Illinois Regulatory Matters

Tax Cuts and Jobs Act (Exelon and ComEd). On January 18, 2018, the ICC approved ComEd's petition filed on January 5, 2018 seeking approval to pass back to customers beginning February 1, 2018 $201 million in tax savings resulting from the enactment of the TCJA through a reduction in electric distribution rates. The amounts being passed back to customers reflect the benefit of lower income tax rates beginning January 1, 2018 and the settlement of a portion of deferred income tax regulatory liabilities established upon enactment of the TCJA. See Note 12 — Income Taxes for additional information on Corporate Tax Reform.

Electric Distribution Formula Rate (Exelon and ComEd). On April 16, 2018, ComEd filed its annual distribution formula rate update with the ICC. The filing establishes the revenue requirement used to set the rates that will take effect in January 2019 after the ICC's review and approval, which is due by December 2018. The revenue requirement requested is based on 2017 actual costs plus projected 2018 capital additions as well as an annual reconciliation of the revenue requirement in effect in 2017 to the actual costs incurred that year. ComEd's 2018 filing request includes a total decrease to the revenue requirement of $23 million, reflecting a decrease of $58 million for the initial revenue requirement for 2018 and an increase of $35 million related to the annual reconciliation for 2017. The revenue requirement for 2018 provides for a weighted average debt and equity return on distribution rate base of 6.52% inclusive of an allowed ROE of 8.69%, reflecting the average rate on 30-year treasury notes plus 580 basis points. The annual reconciliation for 2017 provided for a weighted average debt and equity return on distribution rate base of 6.52% inclusive of an allowed ROE of 8.69%, reflecting the average rate on 30-year treasury notes plus 580 basis points. See table below for ComEd's regulatory

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

assets associated with its electric distribution formula rate. See Note 3 — Regulatory Matters of the Exelon 2017 Form 10-K for additional information on ComEd's distribution formula rate filings.

During the first quarter 2018, ComEd revised its electric distribution formula rate, as provided for by FEJA, to reduce the ROE collar calculation from plus or minus 50 basis points to 0 basis points beginning with the reconciliation filed in 2018 for the 2017 calendar year. This revision effectively offsets the favorable or unfavorable impacts to ComEd's electric distribution formula rate revenues associated with variations in delivery volumes associated with above or below normal weather, numbers of customers or usage per customer. ComEd began reflecting the impacts of this change in its electric distribution formula rate regulatory asset in the first quarter 2017.

Energy Efficiency Formula Rate (Exelon and ComEd). On June 1, 2018, ComEd filed its annual energy efficiency formula rate update with the ICC. The filing establishes the 2019 application year revenue requirement used to set the rates that will take effect in January 2019 after the ICC’s review and approval, which is due by December 2018. The revenue requirement requested is based on 2017 actual costs plus projected 2018 and 2019 expenditures as well as an annual reconciliation of the revenue requirement in effect in 2017 to the actual costs incurred that year. ComEd's 2018 filing request includes a total increase to the revenue requirement of $39 million, reflecting an increase of $38 million for the initial revenue requirement for 2018 and an increase of $1 million related to the annual reconciliation for 2017. The revenue requirement for the 2019 application year provides for a weighted average debt and equity return on rate base of 6.52% inclusive of an allowed ROE of 8.69%, reflecting the average rate on 30-year treasury notes plus 580 basis points.

Zero Emission Standard (Exelon, Generation and ComEd). Pursuant to FEJA, on January 25, 2018, the ICC announced that Generation’s Clinton unit 1, Quad Cities unit 1 and Quad Cities unit 2 nuclear plants were selected as the winning bidders through the IPA's ZEC procurement event. Generation executed the ZEC procurement contracts with Illinois utilities, including ComEd, effective January 26, 2018 and began recognizing revenue. Winning bidders are entitled to compensation for the sale of ZECs retroactive to the June 1, 2017 effective date of FEJA. During the three months ended June 30, 2018, Generation recognized revenue of $52 million. During the six months ended June 30, 2018, Generation recognized revenue of $254 million, of which $150 million related to ZECs generated from June 1, 2017 through December 31, 2017.

ComEd recovers all costs associated with purchasing ZECs through a rate rider that provides for an annual reconciliation and true-up to actual costs incurred by ComEd to purchase ZECs, with any difference to be credited to or collected from ComEd’s retail customers in subsequent periods with interest. ComEd began billing its retail customers under its new ZEC rate rider on June 1, 2017.

On February 14, 2017, two lawsuits were filed in the Northern District of Illinois against the IPA alleging that the state’s ZEC program violates certain provisions of the U.S. Constitution. One lawsuit was filed by customers of ComEd, led by the Village of Old Mill Creek, and the other was brought by the EPSA and three other electric suppliers. Both lawsuits argue that the Illinois ZEC program will distort PJM's FERC-approved energy and capacity market auction system of setting wholesale prices, and seek a permanent injunction preventing the implementation of the program. Exelon intervened and filed motions to dismiss in both lawsuits. In addition, on March 31, 2017, plaintiffs in both lawsuits filed motions for preliminary injunction with the court; the court stayed briefing on the motions for preliminary injunction until the resolution of the motions to dismiss. On July 14, 2017, the district court granted the motions to dismiss. On July 17, 2017, the plaintiffs appealed the decision to the Seventh Circuit. Briefs were fully submitted on December 12, 2017, the Court heard oral argument on January 3, 2018. At the argument, the Court asked for supplemental briefing, which was filed on January 26, 2018. On February 21, 2018, the Seventh Circuit issued an order inviting the Solicitor General to express the views of the United States on the matter. On May 29, 2018, the Solicitor General and FERC filed its brief in the Seventh Circuit Court of Appeals stating that the Illinois ZEC program does not violate federal law or interfere

Table of Contents

with FERC's authority to regulate wholesale power markets. The Illinois Attorney General, EPSA and Exelon have all filed responses to the Solicitor General's brief. The appeal of the Illinois ZEC program remains pending in the Seventh Circuit. Exelon cannot predict the outcome of these lawsuits. It is possible that resolution of these matters could have a material, unfavorable impact on Exelon's and Generation's results of operations, cash flows, and financial positions.
See Note 8 — Early Plant Retirements for additional information regarding the economic challenges facing Generation's Clinton and Quad Cities nuclear plants and the expected benefits of the ZES.

Pennsylvania Regulatory Matters

2018 Pennsylvania Electric Distribution Base Rate Case (Exelon and PECO). On March 29, 2018, PECO filed a request with the PAPUC seeking approval to increase its electric distribution base rates by $82 million beginning January 1, 2019. This requested amount includes the effect of an approximately $71 million reduction as a result of the ongoing annual tax savings beginning January 1, 2019 associated with the TCJA. The requested ROE is 10.95%. PECO expects a decision on its electric distribution rate case proceeding in the fourth quarter of 2018 but cannot predict what increase, if any, the PAPUC will approve.

Tax Cuts and Jobs Act (Exelon and PECO). As part of the rate case filing referenced above, PECO is seeking approval to pass back to electric distribution customers $68 million in 2018 TCJA tax savings, which would be an additional offset to the proposed increase to its electric distribution rates. The amounts being proposed to be passed back to customers reflect the respective annual benefits of lower income tax rates established upon enactment of the TCJA. PECO cannot predict the amount or timing of the refunds the PAPUC will ultimately approve.

On May 17, 2018, the PAPUC issued an order to all Pennsylvania utility companies, including PECO, requiring that the annual tax savings beginning on January 1, 2018 associated with TCJA be passed back to customers. The order directs Pennsylvania utility companies without an existing base rate case, including PECO's gas distribution business, to start passing back the savings from January 1, 2018 onward through a negative surcharge mechanism to be effective on July 1, 2018. Pursuant to the May 17, 2018 Order, PECO filed a negative surcharge mechanism and began on July 1, 2018, to return an estimated $4 million in annual 2018 tax savings to its natural gas distribution customers. For Pennsylvania utility companies with existing base rate cases, including PECO's electric distribution base rate case, the timing of when and how to pass the annual TCJA savings to customers will be resolved through the base rate case proceeding.

See Note 12 — Income Taxes for additional information on Corporate Tax Reform and the table below for regulatory liabilities recognized during 2018 associated with TCJA tax savings that will be passed through future customer rates.

Maryland Regulatory Matters

Tax Cuts and Jobs Act (Exelon, BGE, PHI, Pepco and DPL). On January 12, 2018, the MDPSC issued an order that directed each of BGE, Pepco and DPL to track the impacts of the TCJA beginning January 1, 2018 and file by February 15, 2018 how and when they expect to pass through such impacts to their customers.

On January 31, 2018, the MDPSC approved BGE's petition to pass back to customers $103 million in ongoing annual tax savings resulting from the enactment of the TCJA through a reduction in distribution base rates beginning February 1, 2018, of which $72 million and $31 million were related to electric and natural gas, respectively. The amounts being passed back to customers reflect the ongoing annual benefit of lower income tax rates and the settlement of a portion of deferred income tax regulatory liabilities established upon enactment of the TCJA. BGE's natural gas distribution rate case filing in June

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

2018 included a request to provide to customers the natural gas portion of the January 2018 TCJA savings over a 5-year period.

On April 20, 2018, Pepco entered into a settlement agreement with several parties to resolve all issues in its pending electric distribution base rate case, including the treatment of the annual ongoing TCJA tax savings as well as the TCJA tax savings from January 1, 2018 through the expected effective date of the rate change. On May 31, 2018, the MDPSC issued an order approving the settlement agreement with an effective date of June 1, 2018. See discussion below for additional information.

On February 9, 2018, DPL filed with the MDPSC seeking approval to pass back to customers $13 million in ongoing annual TCJA tax savings through a reduction in electric distribution base rates beginning in 2018. On April 18, 2018, the MDPSC approved a settlement agreement to pass back to customers $14 million in ongoing annual TCJA tax savings through a reduction in electric distribution base rates beginning April 20, 2018. The amounts being passed back to customers reflect the ongoing annual benefit of lower income tax rates and the settlement of a portion of deferred income tax regulatory liabilities established upon enactment of the TCJA. In addition, the MDPSC separately ordered DPL to provide a one-time bill credit to customers of $2 million in June 2018 representing the TCJA tax savings from January 1, 2018 through March 31, 2018.

See Note 12 — Income Taxes for additional information on Corporate Tax Reform and the table below for regulatory liabilities recognized during 2018 associated with TCJA tax savings that will be passed through future customer rates.

The Maryland Strategic Infrastructure Development and Enhancement Program (Exelon and BGE). On December 1, 2017 (and as amended on January 22, 2018), BGE filed an application with the MDPSC seeking approval for a new gas infrastructure replacement plan and associated surcharge, effective for the five-year period from 2019 through 2023. On May 30, 2018, the MDPSC approved with modifications a new infrastructure plan and associated surcharge, subject to BGE's acceptance of the Order. On June 1, 2018, BGE accepted the MDPSC Order and the associated surcharge will be effective in rates beginning in January 2019. The new five-year plan calls for capital expenditures over the 2019-2023 timeframe of $732 million, with an associated revenue requirement of $200 million.

2018 Maryland Natural Gas Distribution Base Rates (Exelon and BGE). On June 8, 2018, BGE filed an application with the MDPSC to increase natural gas revenues by $63 million, reflecting a requested ROE of 10.5%. BGE expects a decision in the first quarter of 2019 but cannot predict how much of the requested increase the MDPSC will approve.

2018 Maryland Electric Distribution Base Rates (Exelon, PHI and Pepco). On January 2, 2018, Pepco filed an application with the MDPSC to increase its annual electric distribution base rates by $41 million, reflecting a requested ROE of 10.1%. On February 5, 2018, Pepco filed with the MDPSC an update to its current distribution base rate case to reflect $31 million in ongoing annual TCJA tax savings, thereby reducing the requested annual base rate increase to $11 million. On March 8, 2018, Pepco filed with the MDPSC a subsequent update to its electric distribution base rate case, which further reduced the requested annual base rate increase to $3 million. On April 20, 2018, Pepco entered into a settlement agreement with several parties to resolve all issues in the rate case and filed the settlement agreement with the MDPSC. The settlement agreement provides for a net decrease to annual electric distribution base rates of $15 million, which includes annual ongoing TCJA tax savings, and reflects a ROE of 9.5%. In addition, the settlement agreement separately provides a one-time bill credit to customers of approximately $10 million representing the TCJA tax savings from January 1, 2018 through the expected rate effective date of June 1, 2018. On May 31, 2018, the MDPSC issued an order approving the settlement agreement with an effective date of June 1, 2018.

2017 Maryland Electric Distribution Base Rates (Exelon, PHI and DPL). On July 14, 2017, DPL filed an application with the MDPSC to increase its annual electric distribution base rates by $27

Table of Contents

million, which was updated to $19 million on November 16, 2017, reflecting a requested ROE of 10.1%. On December 18, 2017, a settlement agreement was filed with the MDPSC wherein DPL will be granted a base rate increase of $13 million, and a ROE of 9.5% solely for purposes of calculating AFUDC and regulatory asset carrying costs. On February 9, 2018, the MDPSC approved the settlement agreement and the new rates became effective.

In the second quarter of 2018, DPL discovered a rate design issue in Maryland such that the current rates are not sufficient to collect the full amount of the $13 million revenue increase agreed to by the parties in the recent settlement. DPL is in discussion with the parties to determine the appropriate resolution to this issue but cannot predict when it will be decided.

Delaware Regulatory Matters

Tax Cuts and Jobs Act (Exelon, PHI and DPL). On January 16, 2018, the DPSC opened a docket indicating that DPL’s TCJA tax savings would be addressed in its pending rate cases. See discussion below for further information on the proposed treatment of the TCJA tax savings in DPL’s pending electric and natural gas distribution base rate cases.

2017 Delaware Electric and Natural Gas Distribution Base Rates (Exelon, PHI and DPL). In 2017 (as updated on February 9, 2018 to reflect $19 million and $7 million of ongoing annual TCJA tax savings for electric and natural gas, respectively), DPL filed applications with the DPSC to increase its annual electric and natural gas distribution base rates by $12 million and $4 million, respectively, reflecting a requested ROE of 10.1%. The ongoing annual TCJA tax savings reflect the ongoing annual benefit of lower income tax rates and the settlement of a portion of deferred income tax regulatory liabilities established upon enactment of the TCJA. Of the proposed electric and natural gas rate increases, $2.5 million of each were put into effect in the fourth quarter 2017 and an additional $3 million and $1 million, respectively, were put into effect in the first quarter 2018, all of which are subject to refund based on the final DPSC order.

On June 27, 2018, DPL entered into a settlement agreement with all active 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%. In addition, the settlement agreement separately 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. 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 DPSC approves the settlement agreement as filed. DPL expects a decision on its natural gas distribution base rate proceeding in the fourth quarter of 2018 but cannot predict how much of the requested increase the DPSC will approve.

See Note 12 — Income Taxes for additional information on Corporate Tax Reform and the table below for regulatory liabilities recognized during 2018 associated with TCJA tax savings that will be passed through future customer rates.

District of Columbia Regulatory Matters

Tax Cuts and Jobs Act (Exelon, PHI and Pepco). On January 23, 2018, the DCPSC opened a rate proceeding directing Pepco to track the impacts of the TCJA beginning January 1, 2018 and file its plan to reduce the current revenue requirement by customer class by February 12, 2018. The DCPSC stated it will address the impact of the TCJA on future rates within Pepco's pending electric distribution base rate case discussed below.

On February 6, 2018, Pepco filed with the DCPSC seeking approval to pass back to customers $39 million in ongoing annual tax savings resulting from the enactment of the TCJA through a reduction

Table of Contents

to existing electric distribution base rates beginning in 2018. On April 17, 2018, Pepco entered into a settlement agreement with several parties to resolve all issues in its pending electric distribution base rate case, including the treatment of the annual ongoing TCJA tax savings as well as the TCJA tax savings from January 1, 2018 through the expected effective date of the rate change. See discussion below for additional information.

2017 District of Columbia Electric Distribution Base Rates (Exelon, PHI and Pepco). On December 19, 2017 (and updated on February 9, 2018), Pepco filed an application with the DCPSC to increase its annual electric distribution base rates by $66 million, reflecting a requested ROE of 10.1%. On April 17, 2018, Pepco entered into a settlement agreement with several parties to resolve both the pending electric distribution base rate case and the $39 million rate reduction request in the TCJA proceeding discussed above and filed the settlement agreement with the DCPSC. The settlement agreement provides for a net decrease to annual electric distribution rates of $24 million, which includes annual ongoing TCJA tax savings, and a ROE of 9.525%. The parties to the settlement agreement have requested that Pepco's new rates be effective on July 1, 2018. In addition, the settlement agreement separately provides a one-time bill credit to customers of approximately $19 million representing the TCJA benefits for the period January 1, 2018 through the expected rate effective date of July 1, 2018. Pepco expects a decision in this matter in the third quarter of 2018.

See Note 12 — Income Taxes for additional information on Corporate Tax Reform and the table below for regulatory liabilities recognized during 2018 associated with TCJA tax savings that will be passed through future customer rates.

New Jersey Regulatory Matters

Tax Cuts and Jobs Act (Exelon, PHI and ACE). On January 31, 2018, the NJBPU issued an order mandating that New Jersey utility companies, including ACE, pass any economic benefit from the TCJA to rate payers. The order directed New Jersey utility companies to file by March 2, 2018 proposed tariff sheets reflecting TCJA benefits, with new rates to be implemented in two phases. In addition, the NJBPU directed New Jersey utility companies to file by March 2, 2018 a Petition with the NJBPU outlining how they propose to refund any over-collection associated with revised rates not being in place from January 1, 2018 through March 31, 2018, with interest.

On March 2, 2018, ACE filed with the NJBPU seeking approval to pass back to customers $23 million in ongoing annual TCJA tax savings through a reduction in electric distribution base rates beginning in 2018. The amounts being passed back to customers would reflect the ongoing annual benefit of lower income tax rates and the settlement of a portion of deferred income tax regulatory liabilities established upon enactment of the TCJA. On March 26, 2018, the NJBPU issued an order accepting ACE's proposed bill reduction related to the lower income tax rates. A portion of the annual decrease in electric distribution base rates totaling approximately $13 million was effective as of April 1, 2018, but considered interim, and the proposed final annual decrease in electric distribution base rates of $23 million, which includes the settlement of the deferred income tax regulatory liability, is still in settlement discussions. It is expected that the NJBPU will address in a future rate proceeding ACE's treatment of the TCJA tax savings for the period January 1, 2018 through July 1, 2018.

See Note 12 — Income Taxes for additional information on Corporate Tax Reform and the table below for regulatory liabilities recognized during 2018 associated with TCJA tax savings that will be passed through future customer rates.

ACE Infrastructure Investment Program Filing (Exelon, PHI and ACE). On February 28, 2018, ACE filed with the NJBPU the company's Infrastructure Investment Program (IIP) proposing to seek recovery of a series of investments through a new rider mechanism, totaling $338 million, between 2019-2022 to provide safe and reliable service for its customers. The IIP will allow for more timely recovery of investments made to modernize and enhance ACE's electric system. ACE currently expects a decision

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

in this matter in the first quarter of 2019 but cannot predict if the NJBPU will approve the application as filed.

Update and Reconciliation of Certain Over and Under Recovered Balances (Exelon, PHI and ACE). On February 5, 2018, ACE submitted its 2018 annual petition with the NJBPU seeking to reconcile and update (i) charges related to the recovery of above-market costs associated with ACE's long-term power purchase contracts with the non-utility generators and (ii) costs related to surcharges for the New Jersey Societal Benefit Program (a statewide public interest program that is intended to benefit low income customers and address other public policy goals) and ACE's uncollectible accounts. As filed, the net impact of adjusting the charges as proposed would have been an overall annual rate decrease of $19 million, including New Jersey sales and use tax. On May 22, 2018, the NJBPU approved a stipulation of settlement among certain interested parties providing for an overall annual rate decrease of $33 million, effective June 1, 2018. The rate decrease was placed into effect provisionally, subject to a review by the NJBPU and the Division of Rate Counsel of the final underlying costs for reasonableness and prudence. This rate decrease will have no effect on ACE's operating income, since these revenues provide for recovery of deferred costs under an approved deferral mechanism. The matter is pending at the NJBPU.

New Jersey Clean Energy Legislation (Exelon, Generation and ACE). On May 23, 2018, the Governor of New Jersey signed new legislation, which became effective immediately, that establishes and modifies New Jersey's clean energy and energy efficiency programs and solar and renewable energy portfolio standards. The new legislation expands the state's renewable portfolio standard to require that 50% of electric generation sold be from renewable energy sources by 2030; modifies the New Jersey solar renewable energy portfolio standard to require that 5.1% of electric generation sold in New Jersey be from solar electric power by 2021, lowers the solar alternative compliance payment amount starting in 2019 and requires the NJBPU to adopt rules to replace the current solar renewable energy credit program; and requires the NJBPU to increase its offshore wind energy credit program to 3,500 MW. The new legislation further imposes an energy efficiency standard that each electric public utility will be required to reduce annual usage by 2% and provides for utilities to annually file for recovery of the costs of the programs, including the revenue impact of sales losses resulting from the programs. The NJBPU is required to initiate a study to determine the savings targets for each public utility, to adopt other rules regarding the programs, and to approve energy efficiency and peak demand reduction programs for each utility. The new legislation also requires the NJBPU to conduct an energy storage analysis including the potential costs and benefits and to initiate a proceeding to establish a goal of achieving 2,000 MW of energy storage by 2030; requires the utilities to conduct a study on voltage optimization on their distribution system; and requires the NJBPU to establish a community solar program to permit customers to participate in a solar project that is not located on the customer's property.

On the same day, the Governor of New Jersey also 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. PSEG's Salem nuclear plant is expected to apply for approval to participate in the ZEC program. 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. 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. Selected nuclear plants will receive ZEC payments for each energy year (12-month period from June 1 through May 31) within 90 days after the completion of such energy year. The quantity of ZECs issued will be determined based on the greater of 40% 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

Table of Contents

the first 3-year eligibility period, the NJBPU has discretion to reduce the ZEC price. Electric distribution utilities in New Jersey, including ACE, will be authorized to collect from retail distribution customers through a non-bypassable charge all costs associated with the utility's procurement of the ZECs. See Note 8 - Early Plant Retirements for additional information on New Jersey's ZEC program potential impacts to PSEG's Salem nuclear plant.

2018 New Jersey Electric Distribution Base Rates (Exelon, PHI and ACE). On June 15, 2018, ACE submitted an application with the NJBPU to increase its annual electric distribution base rates by approximately $99.7 million (before New Jersey sales and use tax), based upon a requested ROE of 10.1%. Included in the $99.7 million request is $40 million of higher depreciation expense related to ACE's updated depreciation study. On July 25, 2018, the NJBPU dismissed ACE's base rate case due to the number of forecasted months included in the twelve month test period. Historically, ACE and other New Jersey utilities have filed distribution base rate cases with a similar number of forecasted months in the test period. ACE expects to file a new application with the NJBPU in the third quarter of 2018 that complies with the required forecasted test period.

New York Regulatory Matters

New York Clean Energy Standard (Exelon and Generation). On August 1, 2016, the New York Public Service Commission (NYPSC) issued an order establishing the New York CES, a component of which is a Tier 3 ZEC program targeted at preserving the environmental attributes of zero-emissions nuclear-powered generating facilities that meet the criteria demonstrating public necessity as determined by the NYPSC. The ZEC price for the first tranche has been set at $17.48 per MWh of production. Following the first tranche, the price will be updated bi-annually.

On October 19, 2016, a coalition of fossil-generation companies filed a complaint in federal district court against the NYPSC alleging that the ZEC program violates certain provisions of the U.S. Constitution; specifically, that the ZEC program interferes with FERC's jurisdiction over wholesale rates and that it discriminates against out of state competitors. On December 9, 2016, Generation and CENG filed a motion to intervene in the case and to dismiss the lawsuit. The State also filed a motion to dismiss. On July 25, 2017, the court granted both motions to dismiss. On August 24, 2017, plaintiffs appealed the decision to the Second Circuit. Plaintiffs-Appellants' initial brief was filed on October 13, 2017. Briefing in the appeal was completed in December 2017 and oral argument was held on March 12, 2018. On May 29, 2018, Generation and CENG provided the court with a copy of the brief submitted by the Solicitor General and FERC in the Seventh Circuit ZEC litigation stating that that the Illinois ZEC program does not violate federal law. The Plaintiffs-Appellants' subsequent response to the brief and our answer to that response also have been provided to the Second Circuit.

In addition, on November 30, 2016, a group of parties, including certain environmental groups and individuals, filed a Petition in New York State court seeking to invalidate the ZEC program. The Petition, which was amended on January 13, 2017, argued that the NYPSC did not have authority to establish the program, that it violated state environmental law and that it violated certain technical provisions of the State Administrative Procedures Act (SAPA) when adopting the ZEC program. On February 15, 2017, Generation and CENG filed a motion to dismiss the state court action. The NYPSC also filed a motion to dismiss the state court action. On March 24, 2017, the plaintiffs filed a memorandum of law opposing the motions to dismiss, and Generation and CENG filed a reply brief on April 28, 2017. Oral argument was held on June 19, 2017. On January 22, 2018, the court dismissed the environmental claims and the majority of the plaintiffs from the case but denied the motions to dismiss with respect to the remaining five plaintiffs and claims, without commenting on the merits of the case. The case is now proceeding to summary judgment with the full record. Exelon's and the state's answers and briefs were filed on March 30, 2018. Plaintiffs' responses were due on May 11, 2018; however, on April 17, 2018, Plaintiffs' filed an order to show cause seeking production of additional documents, including confidential financial information. Exelon and the state filed in opposition to the order to show cause. On July 18, 2018, the court denied the order to show cause and ordered the parties to provide the court within 20 days with an agreed upon final schedule for the remaining brief. After briefing is completed, the court will decide whether or not to set the case for hearing.

Other legal challenges remain possible, the outcomes of which remain uncertain. See Note 8 — Early Plant Retirements for additional information relative to Ginna and Nine Mile Point.

Federal Regulatory Matters

Tax Cuts and Jobs Act and Transmission-Related Income Tax Regulatory Assets (Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE). Pursuant to their respective transmission formula rates, ComEd, PECO, BGE, Pepco, DPL and ACE began passing back to customers on June 1, 2018, the benefit of lower income tax rates effective January 1, 2018. ComEd's, BGE's, Pepco's, DPL's and ACE's transmission formula rates currently do not provide for the pass back or recovery of income tax-related regulatory liabilities or assets, including those established upon enactment of the TCJA.

On December 13, 2016 (and as amended on March 13, 2017), BGE filed with FERC to begin recovering certain existing and future transmission-related income tax regulatory assets through its transmission formula rate. BGE's existing regulatory assets included (1) amounts that, if BGE's transmission formula rate provided for recovery, would have been previously amortized and (2) amounts that would be amortized and recovered prospectively. On November 16, 2017, FERC issued an order rejecting BGE's proposed revisions to its transmission formula rate to recover these transmission-related income tax regulatory assets. On December 18, 2017, BGE filed for clarification and rehearing of FERC's order, still seeking full recovery of its existing transmission-related income tax regulatory asset amounts.

On February 27, 2018 (and updated on March 26, 2018), BGE submitted a letter to FERC advising that the lower federal corporate income tax rate effective January 1, 2018 provided for in TCJA will be reflected in BGE's annual formula rate update effective June 1, 2018, but that the deferred income tax benefits will not be passed back to customers unless BGE's formula rate is revised to provide for pass back and recovery of transmission-related income tax-related regulatory liabilities and assets.

ComEd, Pepco, DPL and ACE have similar transmission-related income tax regulatory liabilities and assets also requiring FERC approval. On February 23, 2018, ComEd, Pepco, DPL, and ACE each filed with FERC to revise their transmission formula rate mechanisms to facilitate passing back to customers ongoing annual TCJA tax savings and to permit recovery of transmission-related income tax regulatory assets. The companies requested the revisions be effective as of April 24, 2018. On April 24, 2018, the FERC issued a letter indicating that the filings were deficient and requiring the parties to file additional information. On July 9, 2018, each of ComEd, Pepco, DPL and ACE submitted such additional information. Similar regulatory assets and liabilities at PECO are not subject to the same FERC transmission rate recovery formula and, thus, are not impacted by BGE's November 16, 2017 FERC order. See below for additional information regarding PECO's transmission formula rate filing.

Each of BGE, ComEd, Pepco, DPL and ACE believe there is sufficient basis to support full recovery of their existing transmission-related income tax regulatory assets, as evidenced by the further pursuit of full recovery with FERC. However, upon further consideration of the November 16, 2017 FERC order, management of each company concluded that the portion of the total transmission-related income tax regulatory assets that would have been previously amortized and recovered through rates had the transmission formula rate provided for such recovery was no longer probable of recovery. As a result, Exelon, ComEd, BGE, PHI, Pepco, DPL and ACE recorded charges to Income tax expense within their Consolidated Statements of Operations and Comprehensive Income in the fourth quarter of 2017, reducing their associated transmission-related income tax regulatory assets.

If any of the companies are ultimately successful with FERC allowing future recovery of these amounts, the associated regulatory assets will be reestablished, with corresponding decreases to Income

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

tax expense. To the extent all or a portion of the prospective amortization amounts were no longer considered probable of recovery, Exelon, ComEd, BGE, PHI, Pepco, DPL and ACE would record additional charges to Income tax expense, which could be up to approximately $84 million, $42 million, $23 million, $19 million, $9 million, $7 million and $3 million, respectively, as of June 30, 2018.

The Utility Registrants cannot predict the outcome of these FERC proceedings.

Transmission Formula Rate (Exelon, ComEd, BGE, PHI, Pepco, DPL and ACE). The following total (decreases)/increases were included in ComEd's, BGE's, Pepco's, DPL's and ACE's 2018 annual electric transmission formula rate updates.

	2018				
Annual Transmission Updates[a][b]	ComEd	BGE	Pepco	DPL	ACE
Initial revenue requirement (decrease) increase	$(44)	$10	$6	$14	$4
Annual reconciliation increase (decrease)	18	4	2	13	(4)
Dedicated facilities increase[c]	—	12	—	—	—
Total revenue requirement (decrease) increase	$(26)	$26	$8	$27	$—
Allowed return on rate base[d]	8.32%	7.61%	7.82%	7.29%	8.02%
Allowed ROE[e]	11.50%	10.50%	10.50%	10.50%	10.50%

____

(a) All rates are effective June 2018, subject to review by the FERC and other parties, which is due by fourth quarter 2018.

(b) The initial revenue requirement changes reflect the annual benefit of lower income tax rates effective January 1, 2018 resulting from the enactment of the TCJA of $69 million, $18 million, $13 million, $12 million and $11 million for ComEd, BGE, Pepco, DPL and ACE, respectively. They do not reflect the pass back or recovery of income tax-related regulatory liabilities or assets, including those established upon enactment of the TCJA. See further discussion above.

(c) BGE's transmission revenues include a FERC-approved dedicated facilities charge to recover the costs of providing transmission service to a specifically designated load by BGE.

(d) Represents the weighted average debt and equity return on transmission rate bases.

(e) As part of the FERC-approved settlement of ComEd’s 2007 transmission rate case, the rate of return on common equity is 11.50% and the common equity component of the ratio used to calculate the weighted average debt and equity return for the transmission formula rate is currently capped at 55%. As part of the FERC-approved settlement of the ROE complaint against BGE, Pepco, DPL and ACE, the rate of return on common equity is 10.50%, inclusive of a 50 basis point incentive adder for being a member of a regional transmission organization.

See Note 3 - Regulatory Matters of the Exelon 2017 Form 10-K for additional information regarding transmission formula rate updates.

Transmission Formula Rate (Exelon and PECO). On May 1, 2017, PECO filed a request with FERC seeking approval to update its transmission rates and change the manner in which PECO’s transmission rate is determined from a fixed rate to a formula rate. The formula rate will be updated annually to ensure that under this rate customers pay the actual costs of providing transmission services. The formula rate filing includes a requested increase of $22 million to PECO’s annual transmission revenues and a requested rate of return on common equity of 11%, inclusive of a 50 basis point adder for being a member of a regional transmission organization. PECO requested that the new transmission rate be effective as of July 2017. On June 27, 2017, FERC issued an Order accepting the filing and suspending the proposed rates until December 1, 2017, subject to refund, and set the matter for hearing and settlement judge procedures. On May 4, 2018, the Chief Administrative Law Judge terminated settlement judge procedures and designated a new presiding judge. PECO cannot predict the final outcome of this proceeding, or the transmission formula FERC may approve.

On May 11, 2018, pursuant to the transmission formula rate request discussed above, PECO made its first annual formula rate update, which included a revenue decrease of $6 million. The revenue

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

decrease of $6 million included an approximately $20 million reduction as a result of the tax savings associated with the TCJA. The updated transmission rate was effective June 1, 2018, subject to refund.

PJM Transmission Rate Design (Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE). 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 December 2025.

On May 31, 2018, FERC issued an order approving the settlement and directed PJM to adjust wholesale transmission rates within 30 days. 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. The Utility Registrants expect to refund or recover these settlement amounts through prospective electric distribution customer rates. On July 2, 2018, a number of parties filed petitions for rehearing or clarification.

Pursuant to the FERC approval of the settlement and the expected refund or recovery of the associated amounts from electric distribution customers, in the second quarter of 2018, the Utility Registrants recorded the following payables to/receivables from PJM and related regulatory assets/liabilities. Generation recorded a $23 million net payable to PJM and a pre-tax charge within Purchased power and fuel expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

	PJM Receivable	PJM Payable	Regulatory Asset	Regulatory Liability
Exelon	$ 197	$ 158	$ 136	$ 198
Generation	—	23	—	—
ComEd	99	—	—	99
PECO	85	—	—	85
BGE	—	51	51	—
PHI[(a)]	13	84	85	14
Pepco	—	84	84	—
DPL	10	—	—	10
ACE	3	—	1	4

____

(a) PHI reflects the consolidated impacts of Pepco, DPL, and ACE.

Operating License Renewals (Exelon and Generation). On August 29, 2012, Generation submitted a hydroelectric license application to FERC for a 46-year license for the Conowingo Hydroelectric Project (Conowingo). In connection with Generation’s efforts to obtain a water quality certification pursuant to Section 401 of the Clean Water Act (401 Certification) with Maryland Department of the Environment (MDE) for Conowingo, Generation continues to work with MDE and other stakeholders to resolve water quality licensing issues, including: (1) water quality, (2) fish habitat, and (3) sediment.

On April 21, 2016, Generation and the U.S. Fish and Wildlife Service of the U.S. Department of the Interior executed a Settlement Agreement resolving all fish passage issues between the parties. The financial impact of the Settlement Agreement is estimated to be $3 million to $7 million per year, on average, over the 46-year life of the new license, including both capital and operating costs. The actual

85

timing and amount of these costs are not currently fixed and may vary significantly from year to year throughout the life of the new license.

On April 27, 2018, the MDE issued its 401 Certification for Conowingo. As issued, the 401 Certification contains numerous conditions, including those relating to reduction of nutrients from upstream sources, removal of all visible trash and debris from upstream sources, and implementation of measures relating to fish passage, which could have a material, unfavorable impact on Exelon’s and Generation’s results of operations, cash flows and financial positions through an increase in capital expenditures and operating costs if implemented. On May 25, 2018, Generation filed complaints in federal and state court, along with a petition for reconsideration with MDE, alleging that the conditions are unfair and onerous violating MDE regulations, state, federal, and constitutional law. Generation also requested that FERC defer action on the federal license while these significant state and federal law issues are pending. Exelon and Generation cannot predict the final outcome or its potential financial impact, if any, on Exelon or Generation.

As of June 30, 2018, $34 million of direct costs associated with Conowingo licensing efforts have been capitalized.

See Note 3 — Regulatory Matters of the Exelon 2017 Form 10-K for additional information on Generation's operating license renewal efforts.

On July 10, 2018, Generation submitted a second 20-year license renewal application with the NRC for Peach Bottom units 2 and 3. Generation anticipates the second license renewal process to take approximately 2 years from the application submission until completion of the NRC’s review process. Peach Bottom units 2 and 3 are licensed to operate through 2033 and 2034, respectively.

Regulatory Assets and Liabilities (Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE)

Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE each prepare their consolidated financial statements in accordance with the authoritative guidance for accounting for certain types of regulation. Under this guidance, regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates or represent billings in advance of expenditures for approved regulatory programs.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

The following tables provide information about the regulatory assets and liabilities of Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE as of June 30, 2018 and December 31, 2017. See Note 3 — Regulatory Matters of the Exelon 2017 Form 10-K for additional information on the specific regulatory assets and liabilities.

June 30, 2018	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Regulatory assets								
Pension and other postretirement benefits[(a)]	$3,777	$—	$—	$—	$—	$—	$—	$—
Deferred income taxes	363	—	353	—	10	10	—	—
AMI programs[(c)]	602	147	30	203	222	149	73	—
Electric distribution formula rate[(d)]	243	243	—	—	—	—	—	—
Energy efficiency costs	284	284	—	—	—	—	—	—
Debt costs	105	35	1	11	69	14	7	5
Fair value of long-term debt	730	—	—	—	594	—	—	—
Fair value of PHI's unamortized energy contracts	638	—	—	—	638	—	—	—
Asset retirement obligations	113	76	22	15	—	—	—	—
MGP remediation costs	276	257	19	—	—	—	—	—
Under-recovered uncollectible accounts	61	61	—	—	—	—	—	—
Renewable energy	252	252	—	—	—	—	—	—
Energy and transmission programs[(e)(f)(g)(h)(i)(j)]	249	8	37	75	129	90	14	25
Deferred storm costs	44	—	—	—	44	10	4	30
Energy efficiency and demand response programs	552	—	1	267	284	206	78	—
Merger integration costs[(k)(l)(m)]	45	—	—	4	41	19	12	10
Under-recovered revenue decoupling[(n)]	37	—	—	9	28	28	—	—
COPCO acquisition adjustment	4	—	—	—	4	—	4	—
Workers compensation and long-term disability costs	34	—	—	—	34	34	—	—
Vacation accrual	30	—	16	—	14	—	8	6
Securitized stranded costs	64	—	—	—	64	—	—	64
CAP arrearage	11	—	11	—	—	—	—	—
Removal costs	545	—	—	—	545	153	95	298
DC PLUG charge	179	—	—	—	179	179	—	—
Other	78	8	12	6	52	38	11	3
Total regulatory assets	9,316	1,371	502	590	2,951	930	306	441
Less: current portion	1,293	237	75	185	512	248	64	60
Total noncurrent regulatory assets	$8,023	$1,134	$427	$405	$2,439	$682	$242	$381

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

June 30, 2018	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Regulatory liabilities								
Other postretirement benefits	$22	$—	$ —	$—	$—	$ —	$—	$—
Deferred income taxes[(b)]	5,118	2,435	—	1,009	1,674	768	497	409
Nuclear decommissioning	2,915	2,430	485	—	—	—	—	—
Removal costs	1,560	1,353	—	79	128	20	108	—
Deferred rent	34	—	—	—	34	—	—	—
Energy efficiency and demand response programs	11	5	4	—	2	—	—	2
DLC program costs	7	—	7	—	—	—	—	—
Electric distribution tax repairs	19	—	19	—	—	—	—	—
Gas distribution tax repairs	7	—	7	—	—	—	—	—
Energy and transmission programs[(e)(f)(g)(h)(i)(j)]	336	154	139	15	28	—	18	10
Over-recovered revenue decoupling[(n)]	19	—	—	19	—	—	—	—
Renewable portfolio standards costs	106	106	—	—	—	—	—	—
Zero emission credit costs	11	11	—	—	—	—	—	—
Over-recovered uncollectible accounts	9	—	—	—	9	—	—	9
Merger integration costs[(l)]	3	—	—	—	3	—	3	—
TCJA income tax benefit over-recoveries[(o)]	94	—	31	18	45	29	7	9
Other	107	14	21	36	36	4	22	8
Total regulatory liabilities	10,378	6,508	713	1,176	1,959	821	655	447
Less: current portion	701	287	168	106	125	30	67	29
Total noncurrent regulatory liabilities	$9,677	$6,221	$ 545	$1,070	$1,834	$ 791	$588	$418

88

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

December 31, 2017	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Regulatory assets								
Pension and other postretirement benefits[a]	$3,848	$—	$—	$—	$—	$—	$—	$—
Deferred income taxes	306	—	297	—	9	9	—	—
AMI programs[c]	640	155	36	214	235	158	77	—
Electric distribution formula rate[d]	244	244	—	—	—	—	—	—
Energy efficiency costs	166	166	—	—	—	—	—	—
Debt costs	116	37	1	11	73	15	8	5
Fair value of long-term debt	758	—	—	—	619	—	—	—
Fair value of PHI's unamortized energy contracts	750	—	—	—	750	—	—	—
Asset retirement obligations	109	73	22	14	—	—	—	—
MGP remediation costs	295	273	22	—	—	—	—	—
Under-recovered uncollectible accounts	61	61	—	—	—	—	—	—
Renewable energy	258	256	—	—	2	—	1	1
Energy and transmission programs[e][g][h][i][j]	82	6	1	23	52	11	15	26
Deferred storm costs	27	—	—	—	27	7	5	15
Energy efficiency and demand response programs	596	—	1	285	310	229	81	—
Merger integration costs[k][l][m]	45	—	—	6	39	20	10	9
Under-recovered revenue decoupling[n]	55	—	—	14	41	38	3	—
COPCO acquisition adjustment	5	—	—	—	5	—	5	—
Workers compensation and long-term disability costs	35	—	—	—	35	35	—	—
Vacation accrual	19	—	6	—	13	—	8	5
Securitized stranded costs	79	—	—	—	79	—	—	79
CAP arrearage	8	—	8	—	—	—	—	—
Removal costs	529	—	—	—	529	150	93	286
DC PLUG charge	190	—	—	—	190	190	—	—
Other	67	8	16	4	39	29	8	4
Total regulatory assets	9,288	1,279	410	571	3,047	891	314	430
Less: current portion	1,267	225	29	174	554	213	69	71
Total noncurrent regulatory assets	$8,021	$1,054	$381	$397	$2,493	$678	$245	$359

December 31, 2017	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Regulatory liabilities								
Other postretirement benefits	$30	$—	$—	$—	$—	$—	$—	$—
Deferred income taxes[b]	5,241	2,479	—	1,032	1,730	809	510	411
Nuclear decommissioning	3,064	2,528	536	—	—	—	—	—
Removal costs	1,573	1,338	—	105	130	20	110	—
Deferred rent	36	—	—	—	36	—	—	—
Energy efficiency and demand response programs	23	4	19	—	—	—	—	—
DLC program costs	7	—	7	—	—	—	—	—
Electric distribution tax repairs	35	—	35	—	—	—	—	—
Gas distribution tax repairs	9	—	9	—	—	—	—	—
Energy and transmission programs[e][f][i][j]	111	47	60	—	4	—	1	3
Renewable portfolio standard costs	63	63	—	—	—	—	—	—
Zero emission credit costs	112	112	—	—	—	—	—	—
Over-recovered uncollectible accounts	2	—	—	—	2	—	—	2
Other	82	6	24	26	26	3	14	6

Total regulatory liabilities	10,388	6,577	690	1,163	1,928	832	635	422
Less: current portion	523	249	141	62	56	3	42	11
Total noncurrent regulatory liabilities	$9,865	$6,328	$ 549	$1,101	$1,872	$ 829	$593	$411

89

Table of Contents

(a) Includes regulatory assets established at the Constellation and PHI merger dates of $414 million and $915 million, respectively, as of June 30, 2018 and $440 million and $953 million, respectively, as of December 31, 2017 related to the rate regulated portions of the deferred costs associated with legacy Constellation's and PHI's pension and other postretirement benefit plans that are being amortized and recovered over approximately 12 years and 3 to 15 years, respectively (as established at the respective acquisition dates). The Utility Registrants are not earning or paying a return on these amounts.

(b) As of June 30, 2018, includes transmission-related income tax regulatory liabilities that require FERC approval separate from the transmission formula rate of $475 million, $133 million, $136 million, $145 million and $146 million for ComEd, BGE, Pepco, DPL and ACE, respectively. As of December 31, 2017, includes transmission-related income tax regulatory liabilities that require FERC approval separate from the transmission formula rate of $484 million, $137 million, $147 million, $148 million and $147 million for ComEd, BGE, Pepco, DPL and ACE, respectively.

(c) As of June 30, 2018, BGE's regulatory asset of $203 million includes $121 million of unamortized incremental deployment costs under the program, $49 million of unamortized costs of the non-AMI meters replaced under the AMI program, and $33 million related to post-test year incremental program deployment costs incurred prior to approval became effective June 2016. As of December 31, 2017, BGE's regulatory asset of $214 million includes $129 million of unamortized incremental deployment costs under the program, $53 million of unamortized costs of the non-AMI meters replaced under the AMI program, and $32 million related to post-test year incremental program deployment costs incurred prior to approval became effective June 2016. Recovery of the post-test year incremental deployment costs will be addressed in a future base rate proceeding.

(d) As of June 30, 2018, ComEd's regulatory asset of $243 million was comprised of $180 million for the 2016, 2017 and 2018 annual reconciliations and $63 million related to significant one-time events. As of December 31, 2017, ComEd's regulatory asset of $244 million was comprised of $186 million for the 2016 and 2017 annual reconciliations and $58 million related to significant one-time events.

(e) As of June 30, 2018, ComEd's regulatory asset of $8 million represents transmission costs recoverable through its FERC approved formula rate. As of June 30, 2018, ComEd's regulatory liability of $154 million included $99 million related to the PJM Transmission Rate Design Settlement, $23 million related to over-recovered energy costs and $32 million associated with revenues received for renewable energy requirements. As of December 31, 2017, ComEd's regulatory asset of $6 million represents transmission costs recoverable through its FERC approved formula rate. As of December 31, 2017, ComEd's regulatory liability of $47 million included $14 million related to over-recovered energy costs and $33 million associated with revenues received for renewable energy requirements.

(f) As of June 30, 2018, PECO's regulatory asset of $37 million represents the under-recovered natural gas costs under the PGC. As of December 31, 2017, PECO's regulatory asset of $1 million is related to under-recovered costs under the TSC program. As of June 30, 2018, PECO's regulatory liability of $139 million included $85 million related to the PJM Transmission Rate Design Settlement, $46 million related to over-recovered costs under the DSP program, $3 million related to the over-recovered transmission service charges and $5 million related to over-recovered non-bypassable transmission service charges. As of December 31, 2017, PECO's regulatory liability of $60 million included $36 million related to over-recovered costs under the DSP program, $12 million related to over-recovered non-bypassable transmission service charges and $12 million related to the over-recovered natural gas costs under the PGC.

(g) As of June 30, 2018, BGE's regulatory asset of $75 million included $51 million related to the PJM Transmission Rate Design Settlement, $14 million of costs associated with transmission costs recoverable through its FERC approved formula rate, $7 million related to under-recovered electric energy costs and $3 million of abandonment costs to be recovered upon FERC approval. As of June 30, 2018, BGE's regulatory liability of $15 million related to over-recovered natural gas costs. As of December 31, 2017, BGE's regulatory asset of $23 million included $7 million of costs associated with transmission costs recoverable through its FERC approved formula rate, $5 million related to under-recovered electric energy costs, $3 million of abandonment costs to be recovered upon FERC approval and $8 million of under-recovered natural gas costs.

(h) As of June 30, 2018, Pepco's regulatory asset of $90 million included $84 million related to the PJM Transmission Rate Design Settlement, $4 million of transmission costs recoverable through its FERC approved formula rate and $2 million related to under-recovered electric energy costs. As of December 31, 2017, Pepco's regulatory asset of $11 million included $3 million of transmission costs recoverable through its FERC approved formula rate and $8 million of under-recovered electric energy costs.

(i) As of June 30, 2018, DPL's regulatory asset of $14 million included $12 million of transmission costs recoverable through its FERC approved formula rate and $2 million related to under-recovered electric energy costs. As of June 30, 2018, DPL's regulatory liability of $18 million included $10 million related to the PJM Transmission Rate Design Settlement and $8 million related to over-recovered electric energy and gas fuel costs. As of December 31, 2017, DPL's regulatory asset of $15 million included $8 million of transmission costs recoverable through its FERC approved formula rate and $7 million related to under-recovered electric energy costs. As of December 31, 2017, DPL's regulatory liability of $1 million related to over-recovered electric energy costs.

(j) As of June 30, 2018, ACE's regulatory asset of $25 million included $1 million related to the PJM Transmission Rate Design Settlement, $8 million of transmission costs recoverable through its FERC approved formula rate and $16 million of under-recovered electric energy costs. As of June 30, 2018, ACE's regulatory liability of $10 million included $4 million related to the PJM Transmission Rate Design Settlement and $6 million related to over-recovered electric energy costs. As of December 31, 2017, ACE's regulatory asset of $26 million included $11 million of transmission costs recoverable through its FERC approved formula rate and $15 million of under-recovered electric energy costs. As of December 31, 2017, ACE's regulatory liability of $3 million related to over-recovered electric energy costs.

(k) As of June 30, 2018, Pepco’s regulatory asset of $19 million represents previously incurred PHI integration costs, including $10 million authorized for recovery in Maryland and $9 million expected to be recovered in the District of Columbia service territory. As of December 31, 2017, Pepco’s regulatory asset of $20 million represents previously incurred PHI integration costs, including $11 million authorized for recovery in Maryland and $9 million expected to be recovered in the District of Columbia service territory.

(l) As of June 30, 2018, DPL’s regulatory asset of $12 million represents previously incurred PHI integration costs, including $4 million authorized for recovery in Maryland, $4 million authorized for recovery in Delaware electric rates, $2 million authorized for recovery in Delaware gas rates and $2 million expected to be recovered in electric rates in the Delaware and Maryland service territories. As of June 30, 2018, DPL’s regulatory liability of $3 million represents net synergy savings incurred related to PHI integration costs that are expected to be returned in electric and gas rates in the Delaware service territory. As of December 31, 2017, DPL’s regulatory asset of $10 million represents previously incurred PHI integration costs, including $4 million authorized for recovery in Maryland, $5 million authorized for recovery in Delaware electric rates, and $1 million expected to be recovered in electric and gas rates in the Maryland and Delaware service territories.

(Dollars in millions, except per share data, unless otherwise noted)

(m) As of June 30, 2018 and December 31, 2017, ACE’s regulatory asset of $10 million and $9 million, respectively, represents previously incurred PHI integration costs expected to be recovered in the New Jersey service territory.

(n) Represents the electric and natural gas distribution costs recoverable from customers under BGE’s decoupling mechanism. As of June 30, 2018, BGE had a regulatory asset of $9 million related to under-recovered electric revenue decoupling and a regulatory liability of $19 million related to over-recovered natural gas revenue decoupling. As of December 31, 2017, BGE had a regulatory asset of $10 million related to under-recovered electric revenue decoupling and $4 million related to under-recovered natural gas revenue decoupling.

(o) Represents over-recoveries related to the change in the federal income tax rate with the enactment of the TCJA. These regulatory liabilities will be amortized as the TCJA income tax benefits are passed back to customers. See Tax Cuts and Jobs Act disclosures above for additional information on the regulatory proceedings.

Capitalized Ratemaking Amounts Not Recognized (Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE)

The following table presents authorized amounts capitalized for ratemaking purposes related to earnings on shareholders’ investment that are not recognized for financial reporting purposes on Exelon's, ComEd's, PECO's, BGE's, PHI's, Pepco's, DPL's and ACE's Consolidated Balance Sheets. These amounts will be recognized as revenues in the related Consolidated Statements of Operations and Comprehensive Income in the periods they are billable to our customers.

	Exelon	ComEd[(a)]	PECO	BGE[(b)]	PHI	Pepco[(c)]	DPL[(c)]	ACE
June 30, 2018	$ 67	$ 7	$ —	$ 51	$ 9	$ 5	$ 4	$ —

	Exelon	ComEd[(a)]	PECO	BGE[(b)]	PHI	Pepco[(c)]	DPL[(c)]	ACE
December 31, 2017	$ 69	$ 6	$ —	$ 53	$ 10	$ 6	$ 4	$ —

(a) Reflects ComEd's unrecognized equity returns earned for ratemaking purposes on its electric distribution formula rate regulatory assets.

(b) BGE's authorized amounts capitalized for ratemaking purposes primarily relate to earnings on shareholders' investment on its AMI programs.

(c) Pepco's and DPL's authorized amounts capitalized for ratemaking purposes relate to earnings on shareholders' investment on their respective AMI Programs and Energy Efficiency and Demand Response Programs. The earnings on energy efficiency are on Pepco DC and DPL DE programs only.

Purchase of Receivables Programs (Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE)

ComEd, PECO, BGE, Pepco, DPL and ACE are required, under separate legislation and regulations in Illinois, Pennsylvania, Maryland, District of Columbia and New Jersey, to purchase certain receivables from retail electric and natural gas suppliers that participate in the utilities' consolidated billing. ComEd, BGE, Pepco and DPL purchase receivables at a discount to recover primarily uncollectible accounts expense from the suppliers. PECO is required to purchase receivables at face value and is permitted to recover uncollectible accounts expense, including those from Third Party Suppliers, from customers through distribution rates. ACE purchases receivables at face value. ACE recovers all uncollectible accounts expense, including those from Third Party Suppliers, through the Societal Benefits Charge (SBC) rider, which includes uncollectible accounts expense as a component. The SBC is filed annually with the NJBPU. Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE do not record unbilled commodity receivables under the POR programs. Purchased billed receivables are classified in Other accounts receivable, net on Exelon’s, ComEd’s, PECO’s, BGE’s, PHI's, Pepco's, DPL's and ACE's Consolidated Balance Sheets. The following tables provide information about the purchased receivables of those companies as of June 30, 2018 and December 31, 2017.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

As of June 30, 2018	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Purchased receivables	$ 305	$ 98	$ 66	$ 54	$ 87	$ 59	$ 8	$ 20
Allowance for uncollectible accounts[(a)]	(31)	(15)	(4)	(3)	(9)	(5)	(1)	(3)
Purchased receivables, net	$ 274	$ 83	$ 62	$ 51	$ 78	$ 54	$ 7	$ 17
As of December 31, 2017	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Purchased receivables	$ 298	$ 87	$ 70	$ 58	$ 83	$ 56	$ 9	$ 18
Allowance for uncollectible accounts[(a)]	(31)	(14)	(5)	(3)	(9)	(5)	(1)	(3)
Purchased receivables, net	$ 267	$ 73	$ 65	$ 55	$ 74	$ 51	$ 8	$ 15

(a) For ComEd, BGE, Pepco and DPL, reflects the incremental allowance for uncollectible accounts recorded, which is in addition to the purchase discount. For ComEd, the incremental uncollectible accounts expense is recovered through its Purchase of Receivables with Consolidated Billing tariff.

7. Impairment of Long-Lived Assets (Exelon and Generation)

Registrants evaluate long-lived assets for recoverability whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. In the second quarter of 2018, updates to Exelon's long-term view of energy and capacity prices suggested that the carrying value of a group of merchant wind assets, located in West Texas, may be impaired. Upon review, the estimated undiscounted future cash flows and fair value of the group were less than its carrying value. The fair value analysis was based on the income approach using significant unobservable inputs (Level 3) including revenue and generation forecasts, projected capital and maintenance expenditures and discount rates. As a result, long-lived merchant wind assets held and used with a net carrying amount of $41 million were fully impaired and a pre-tax impairment charge of $41 million was recorded during the second quarter of 2018 within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

During the first quarter of 2018, Mystic unit 9 did not clear in the ISO-NE capacity auction for the 2021 - 2022 planning year. On March 29, 2018, Generation announced it had formally notified ISO-NE of the early retirement of its Mystic Generating Station's units 7, 8, 9 and the Mystic Jet unit (Mystic Generating Station assets) absent regulatory reforms. These events suggested that the carrying value of its New England asset group may be impaired. As a result, Generation completed a comprehensive review of the estimated undiscounted future cash flows of the New England asset group and no impairment charge was required. Further developments such as the failure of ISO-NE to adopt interim and long-term solutions for reliability and fuel security could potentially result in future impairments of the New England asset group, which could be material. See Note 8 — Early Plant Retirements for additional information on the early retirement of the Mystic Generating Station assets.

On May 2, 2017, EGTP entered into a consent agreement with its lenders to initiate an orderly sales process to sell the assets of its wholly owned subsidiaries. As a result, Exelon and Generation classified certain of EGTP's assets and liabilities as held for sale at their respective fair values less costs to sell and recorded a pre-tax impairment charge of $460 million within Operating and maintenance expense on their Consolidated Statements of Operations and Comprehensive Income of which $418 million was recorded in the second quarter of 2017. On November 7, 2017, EGTP and its wholly owned subsidiaries filed voluntary petitions for relief under Chapter 11 of Title 11 of the United States Code in the United States Bankruptcy Court for the District of Delaware and, as a result, Exelon and Generation deconsolidated EGTP's assets and liabilities from their consolidated financial statements. See Note 4 — Mergers, Acquisitions and Dispositions for additional information.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

8. Early Plant Retirements (Exelon and Generation)

Exelon and Generation continue to evaluate the current and expected economic value of each of Generation's plants. Factors that will continue to affect the economic value of Generation's plants include, but are not limited to: market power prices, results of capacity auctions, potential legislative and regulatory solutions to ensure plants are fairly compensated for benefits they provide through their carbon-free emissions, reliability, or fuel security, and the impact of potential rules from the EPA requiring reduction of carbon and other emissions and the efforts of states to implement those final rules. The precise timing of an early retirement date for any plant, and the resulting financial statement impacts, may be affected by many factors, including the status of potential regulatory or legislative solutions, results of any transmission system reliability study assessments, the nature of any co-owner requirements and stipulations, and decommissioning trust fund requirements for nuclear plants, among other factors. However, the earliest retirement date for any plant would usually be the first year in which the unit does not have capacity or other obligations, and where applicable, just prior to its next scheduled nuclear refueling outage.

In 2015 and 2016, Generation identified the Clinton and Quad Cities nuclear plants in Illinois, Ginna and Nine Mile Point nuclear plants in New York and Three Mile Island nuclear plant in Pennsylvania as having the greatest risk of early retirement based on economic valuation and other factors.

Assuming the continued effectiveness of the Illinois ZES and the New York CES, Generation and CENG, through its ownership of Ginna and Nine Mile Point, no longer consider Clinton, Quad Cities, Ginna or Nine Mile Point to be at heightened risk for early retirement. However, to the extent either the Illinois ZES or the New York CES programs do not operate as expected over their full terms, each of these nuclear plants could again be at heightened risk for early retirement, which could have a material impact on Exelon's and Generation's future results of operations, cash flows and financial positions. See Note 6 — Regulatory Matters for additional information on the Illinois ZES and New York CES.

In Pennsylvania, the TMI nuclear plant did not clear in the May 2017 PJM capacity auction for the 2020-2021 planning year, the third consecutive year that TMI failed to clear the PJM base residual capacity auction. The plant is currently committed to operate through May 2019 and is licensed to operate through 2034. On May 30, 2017, based on these capacity auction results, prolonged periods of low wholesale power prices, and the absence of federal or state policies that place a value on nuclear energy for its ability to produce electricity without air pollution, Exelon announced that Generation will permanently cease generation operations at TMI on or about September 30, 2019. Generation has filed the required market and regulatory notifications to shut down the plant. PJM has subsequently notified Generation that it has not identified any reliability issues and has approved the deactivation of TMI as proposed.

On February 2, 2018, Exelon announced that Generation will permanently cease generation operations at Oyster Creek nuclear plant at the end of its current operating cycle by October 2018. In 2010, Generation announced that Oyster Creek would retire by the end of 2019 as part of an agreement with the State of New Jersey to avoid significant costs associated with the construction of cooling towers to meet the State's then new environmental regulations. Since then, like other nuclear sites, Oyster Creek has continued to face rising operating costs amid a historically low wholesale power price environment. The decision to retire Oyster Creek in 2018 at the end of its current operating cycle involved consideration of several factors, including economic and operating efficiencies, and avoids a refueling outage scheduled for the fall of 2018 that would have required advanced purchasing of fuel fabrication and materials beginning in late February 2018. Generation has filed the required market and regulatory notifications to shut down the plant. PJM has subsequently notified Generation that it has not identified any reliability issues and has approved the deactivation of Oyster Creek as proposed.

As a result of these early nuclear plant retirement decisions, Exelon and Generation recognized one-time charges in Operating and maintenance expense related to materials and supplies inventory

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

reserve adjustments, employee-related costs and CWIP impairments, among other items. In addition to these one-time charges, annual incremental non-cash charges to earnings stemming from shortening the expected economic useful lives primarily related to accelerated depreciation of plant assets (including any ARC), accelerated amortization of nuclear fuel, and additional ARO accretion expense associated with the changes in decommissioning timing and cost assumptions were also recorded. See Note 13 — Nuclear Decommissioning for additional information on changes to the nuclear decommissioning ARO balance.

During the three and six months ended June 30, 2018, both Exelon's and Generation's results include a net incremental $173 million and $351 million, respectively, of total pre-tax expense associated with the early retirement decisions for TMI and Oyster Creek, as summarized in the table below.

Income statement expense (pre-tax)	Q2 2018	YTD 2018
Depreciation and amortization[(a)]		
Accelerated depreciation[(b)]	$ 152	$ 289
Accelerated nuclear fuel amortization	19	34
Operating and maintenance[(c)]	2	28
Total	$ 173	$ 351

(a) Reflects incremental accelerated depreciation and amortization for TMI and Oyster Creek for the three and six months ended June 30, 2018. The Oyster Creek year-to-date amounts are from February 2, 2018 through June 30, 2018.
(b) Reflects incremental accelerated depreciation of plant assets, including any ARC.
(c) Primarily includes materials and supplies inventory reserve adjustments, employee related costs and CWIP impairments.

Exelon's and Generation's 2017 results included a net incremental $339 million of total pre-tax expense associated with the early retirement decision for TMI, as summarized in the table below.

Income statement expense (pre-tax)	Q2 2017	Q3 2017	Q4 2017	YTD 2017
Depreciation and amortization[(a)]				
Accelerated depreciation[(b)]	$ 35	$ 106	$ 109	$ 250
Accelerated nuclear fuel amortization	2	6	4	12
Operating and maintenance[(c)]	71	5	1	77
Total	$ 108	$ 117	$ 114	$ 339

(a) Reflects incremental charges for TMI including incremental accelerated depreciation and amortization from May 30, 2017 through December 31, 2017.
(b) Reflects incremental accelerated depreciation of plant assets, including any ARC.
(c) Primarily includes materials and supplies inventory reserve adjustments, employee related costs and CWIP impairments.

In 2017, PSEG made public similar financial challenges facing its New Jersey nuclear plants including Salem, of which Generation owns a 42.59% ownership interest. Although Salem is committed to operate through May 2021, the plant faces continued economic challenges and PSEG, as the operator of the plant, is exploring all options.

On May 23, 2018, the Governor 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. The NJBPU has 180 days from the effective date to establish procedures for implementation of the ZEC

94

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

program and 330 days from the effective date to determine which nuclear power plants are selected to receive ZECs under the program. Selected nuclear plants will receive ZEC payments for each energy year (12-month period from June 1 through May 31) within 90 days after the completion of such energy year. 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. See Note 6 — Regulatory Matters for additional information on the New Jersey ZEC program.

The following table provides the balance sheet amounts as of June 30, 2018 for Generation's ownership share of the significant assets and liabilities associated with Salem.

	June 30, 2018
Asset Balances	
Materials and supplies inventory	$ 45
Nuclear fuel inventory, net	94
Completed plant, net	611
Construction work in progress	28
Liability Balances	
Asset retirement obligation	(451)
NRC License Renewal Term	2036 (unit 1) 2040 (unit 2)

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 absent regulatory reforms on June 1, 2022, at the end of the current capacity commitment for Mystic units 7 and 8. Mystic unit 9 is currently committed through May 2021. Absent any regulatory reforms to properly value reliability and regional fuel security, these units will not participate in the Forward Capacity Auction (FCA) scheduled for February 2019 for the 2022 - 2023 capacity commitment period.

The ISO-NE announced that it would take a three-step approach to fuel security. First, 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 capacity commitment periods. Second, ISO-NE planned to file tariff revisions to allow it to retain other resources for fuel security in the capacity market if necessary in the future. Third, ISO-NE stated its intention to work with stakeholders to develop long-term market rule changes to address system resiliency considering significant reliability risks identified in ISO-NE's January 2018 fuel security report. Changes to market rules are necessary because critical units to the region, such as Mystic units 8 and 9, cannot recover future operating costs, including the cost of procuring fuel.

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. Among the costs included in the filing are costs associated with the Distrigas facility. Generation asked that FERC establish an expedited settlement process that would allow Generation to know the outcome of the cost-of-service proceeding prior to making a final decision as to whether to unconditionally retire the plants beginning June 1, 2022. A number of parties filed protests in response to the May 16, 2018 filing.

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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

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. In addition, notwithstanding its denial of the waiver request, FERC stated that it will continue to evaluate Mystic's May 16, 2018 cost-of-service agreement filing. On July 13, 2018, FERC issued an order accepting Generation's cost-of-service agreement for filing and making findings on certain issues, including that recovery of fuel supply costs for the Distrigas facility are not prohibited if they are just and reasonable. Additionally, the order established hearing procedures on an expedited schedule. Any settlement discussions are to be undertaken on a parallel track with the hearing.

Exelon and Generation cannot predict the final outcome of these proceedings or the potential financial impact, if any, on Exelon or Generation.

The following table provides the balance sheet amounts as of June 30, 2018 for Generation's significant assets and liabilities associated with the Mystic Generating Station assets.

	June 30, 2018
Asset Balances	
Materials and supplies inventory	$ 26
Fuel inventory	19
Completed plant, net	887
Construction work in progress	3
Prepaid expenses[(a)]	11
Liability Balances	
Asset retirement obligation	(5)
Accrued expenses[(a)]	(2)

(a) Reflects ending balances only as they relate to Mystic's Long-term Service Agreement.

96

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

9. Fair Value of Financial Assets and Liabilities (All Registrants)

Fair Value of Financial Liabilities Recorded at Amortized Cost

The following tables present the carrying amounts and fair values of the Registrants' short-term liabilities, long-term debt, SNF obligation and trust preferred securities (long-term debt to financing trusts or junior subordinated debentures) as of June 30, 2018 and December 31, 2017:

Exelon

	June 30, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities[(a)]	$1,252	$—	$1,252	$ —	$1,252
Long-term debt (including amounts due within one year)[(b)(c)]	34,337	—	32,388	2,154	34,542
Long-term debt to financing trusts[(d)]	389	—	—	420	420
SNF obligation	1,157	—	921	—	921

	December 31, 2017				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities[(a)]	$929	$—	$ 929	$ —	$ 929
Long-term debt (including amounts due within one year)[(b)(c)]	34,264	—	34,735	1,970	36,705
Long-term debt to financing trusts[(d)]	389	—	—	431	431
SNF obligation	1,147	—	936	—	936

Generation

	June 30, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[(b)(c)]	$8,886	$—	$7,461	$1,532	$8,993
SNF obligation	1,157	—	921	—	921

	December 31, 2017				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities[(a)]	$2	$—	$ 2	$ —	$ 2
Long-term debt (including amounts due within one year)[(b)(c)]	8,990	—	7,839	1,673	9,512
SNF obligation	1,147	—	936	—	936

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

ComEd

	June 30, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities[a]	$320	$—	$320	$—	$320
Long-term debt (including amounts due within one year)[b][c]	7,695	—	7,865	—	7,865
Long-term debt to financing trusts[d]	205	—	—	219	219

	December 31, 2017				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[b][c]	$7,601	$—	$8,418	$—	$8,418
Long-term debt to financing trusts[d]	205	—	—	227	227

PECO

	June 30, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities[a]	$50	$—	$ 50	$—	$ 50
Long-term debt (including amounts due within one year)[b][c]	2,773	—	2,819	50	2,869
Long-term debt to financing trusts[d]	184	—	—	201	201

	December 31, 2017				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[b][c]	$2,903	$—	$3,194	$—	$3,194
Long-term debt to financing trusts[d]	184	—	—	204	204

BGE

	June 30, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities[a]	$136	$—	$136	$—	$136
Long-term debt (including amounts due within one year)[b][c]	2,578	—	2,629	—	2,629

98

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	December 31, 2017				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities[(a)]	$77	$—	$77	$—	$77
Long-term debt (including amounts due within one year)[(b)(c)]	2,577	—	2,825	—	2,825

PHI

	June 30, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities[(a)]	$247	$—	$247	$—	$247
Long-term debt (including amounts due within one year)[(b)(c)]	6,116	—	5,300	572	5,872
	December 31, 2017				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities[(a)]	$350	$—	$350	$—	$350
Long-term debt (including amounts due within one year)[(b)(c)]	5,874	—	5,722	297	6,019

Pepco

	June 30, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[(b)(c)]	$2,631	$—	$2,863	$107	$2,970
	December 31, 2017				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities[(a)]	$26	$—	$26	$—	$26
Long-term debt (including amounts due within one year)[(b)(c)]	2,540	—	3,114	9	3,123

DPL

	June 30, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[(b)(c)]	$1,494	$—	$1,295	$196	$1,491

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	December 31, 2017				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities[a]	$216	$—	$216	$ —	$216
Long-term debt (including amounts due within one year)[b][c]	1,300	—	1,393	—	1,393

ACE

	June 30, 2018				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities[a]	$247	$—	$247	$ —	$247
Long-term debt (including amounts due within one year)[b][c]	1,107	—	898	269	1,167

	December 31, 2017				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities[a]	$108	$—	$108	$ —	$108
Long-term debt (including amounts due within one year)[b][c]	1,121	—	949	288	1,237

(a) Level 1 securities consist of dividends payable (included in other current liabilities). Level 2 securities consist of short term borrowings.

(b) Includes unamortized debt issuance costs which are not fair valued of $213 million, $55 million, $59 million, $20 million, $16 million, $12 million, $35 million, $12 million and $4 million for Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively, as of June 30, 2018. Includes unamortized debt issuance costs which are not fair valued of $201 million, $60 million, $52 million, $17 million, $17 million, $6 million, $32 million, $11 million and $5 million for Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively, as of December 31, 2017.

(c) Level 2 securities consist of fixed-rate taxable debt securities, fixed-rate tax-exempt debt, variable rate tax-exempt debt and variable rate non-recourse debt. Level 3 securities consist of fixed-rate private placement taxable debt securities, fixed rate nonrecourse debt, government-backed fixed rate non-recourse debt and loan agreements.

(d) Includes unamortized debt issuance costs which are not fair valued of $1 million and $1 million for Exelon and ComEd, respectively, as of June 30, 2018 and December 31, 2017.

Recurring Fair Value Measurements

Exelon records the fair value of assets and liabilities in accordance with the hierarchy established by the authoritative guidance for fair value measurements. The hierarchy prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

- Level 1 — quoted prices (unadjusted) in active markets for identical assets or liabilities that the Registrants have the ability to liquidate as of the reporting date.
- Level 2 — inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data.
- Level 3 — unobservable inputs, such as internally developed pricing models or third-party valuations for the asset or liability due to little or no market activity for the asset or liability.

Transfers in and out of levels are recognized as of the end of the reporting period when the transfer occurred. Given derivatives categorized within Level 1 are valued using exchange-based quoted prices within observable periods, transfers between Level 2 and Level 1 were not material. Additionally, there

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

were no material transfers between Level 1 and Level 2 during the six months ended June 30, 2018 for cash equivalents, nuclear decommissioning trust fund investments, Pledged assets for Zion Station decommissioning, Rabbi trust investments, and Deferred compensation obligations. For derivative contracts, transfers into Level 2 from Level 3 generally occur when the contract tenor becomes more observable and due to changes in market liquidity or assumptions for certain commodity contracts.

Generation and Exelon

In accordance with the applicable guidance on fair value measurement, certain investments that are measured at fair value using the NAV per share as a practical expedient are no longer classified within the fair value hierarchy and are included under "Not subject to leveling" in the table below.

The following tables present assets and liabilities measured and recorded at fair value on Exelon's and Generation’s Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of June 30, 2018 and December 31, 2017:

	Generation					Exelon				
As of June 30, 2018	Level 1	Level 2	Level 3	Not subject to leveling	Total	Level 1	Level 2	Level 3	Not subject to leveling	Total
Assets										
Cash equivalents[(a)]	$301	$ —	$ —	$ —	$ 301	$660	$ —	$ —	$ —	$ 660
NDT fund investments										
Cash equivalents[(b)]	212	94	—	—	306	212	94	—	—	306
Equities	3,429	1,174	—	1,948	6,551	3,429	1,174	—	1,948	6,551
Fixed income										
Corporate debt	—	1,593	231	—	1,824	—	1,593	231	—	1,824
U.S. Treasury and agencies	2,007	94	—	—	2,101	2,007	94	—	—	2,101
Foreign governments	—	61	—	—	61	—	61	—	—	61
State and municipal debt	—	236	—	—	236	—	236	—	—	236
Other[(c)]	—	33	—	908	941	—	33	—	908	941
Fixed income subtotal	2,007	2,017	231	908	5,163	2,007	2,017	231	908	5,163
Middle market lending	—	—	354	216	570	—	—	354	216	570
Private equity	—	—	—	270	270	—	—	—	270	270
Real estate	—	—	—	506	506	—	—	—	506	506
NDT fund investments subtotal[(d)]	5,648	3,285	585	3,848	13,366	5,648	3,285	585	3,848	13,366
Pledged assets for Zion Station decommissioning										
Cash equivalents	3	—	—	—	3	3	—	—	—	3
Middle market lending	—	—	18	—	18	—	—	18	—	18
Pledged assets for Zion Station decommissioning subtotal[(e)]	3	—	18	—	21	3	—	18	—	21

101

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	Generation					Exelon				
As of June 30, 2018	Level 1	Level 2	Level 3	Not subject to leveling	Total	Level 1	Level 2	Level 3	Not subject to leveling	Total
Rabbi trust investments										
Cash equivalents	5	—	—	—	5	45	—	—	—	45
Mutual funds	24	—	—	—	24	73	—	—	—	73
Fixed income	—	—	—	—	—	—	18	—	—	18
Life insurance contracts	—	22	—	—	22	—	71	36	—	107
Rabbi trust investments subtotal[(f)]	29	22	—	—	51	118	89	36	—	243
Commodity derivative assets										
Economic hedges	237	2,091	1,770	—	4,098	237	2,091	1,770	—	4,098
Proprietary trading	—	138	83	—	221	—	138	83	—	221
Effect of netting and allocation of collateral[(g) (h)]	(219)	(1,912)	(950)	—	(3,081)	(219)	(1,912)	(950)	—	(3,081)
Commodity derivative assets subtotal	18	317	903	—	1,238	18	317	903	—	1,238
Interest rate and foreign currency derivative assets										
Derivatives designated as hedging instruments	—	16	—	—	16	—	16	—	—	16
Economic hedges	—	6	—	—	6	—	6	—	—	6
Effect of netting and allocation of collateral	—	(4)	—	—	(4)	—	(4)	—	—	(4)
Interest rate and foreign currency derivative assets subtotal	—	18	—	—	18	—	18	—	—	18
Other investments	—	—	36	—	36	—	—	36	—	36
Total assets	5,999	3,642	1,542	3,848	15,031	6,447	3,709	1,578	3,848	15,582
Liabilities										
Commodity derivative liabilities										
Economic hedges	(329)	(2,244)	(1,234)	—	(3,807)	(329)	(2,244)	(1,486)	—	(4,059)
Proprietary trading	—	(152)	(20)	—	(172)	—	(152)	(20)	—	(172)
Effect of netting and allocation of collateral[(g) (h)]	255	2,120	1,088	—	3,463	255	2,120	1,088	—	3,463
Commodity derivative liabilities subtotal	(74)	(276)	(166)	—	(516)	(74)	(276)	(418)	—	(768)
Interest rate and foreign currency derivative										

liabilities										
Derivatives designated as hedging instruments	—	—	—	—	—	—	(8)	—	—	(8)
Economic hedges	—	(3)	—	—	(3)	—	(3)	—	—	(3)
Effect of netting and allocation of collateral	—	4	—	—	4	—	4	—	—	4
Interest rate and foreign currency derivative liabilities subtotal	—	1	—	—	1	—	(7)	—	—	(7)
Deferred compensation obligation	—	(34)	—	—	(34)	—	(136)	—	—	(136)
Total liabilities	(74)	(309)	(166)	—	(549)	(74)	(419)	(418)	—	(911)
Total net assets	$5,925	$3,333	$1,376	$ 3,848	$14,482	$6,373	$3,290	$1,160	$ 3,848	$14,671

102

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	Generation					Exelon				
As of December 31, 2017	Level 1	Level 2	Level 3	Not subject to leveling	Total	Level 1	Level 2	Level 3	Not subject to leveling	Total
Assets										
Cash equivalents[a]	$168	$ —	$ —	$ —	$168	$656	$ —	$ —	$ —	$656
NDT fund investments										
Cash equivalents[b]	135	85	—	—	220	135	85	—	—	220
Equities	4,163	915	—	2,176	7,254	4,163	915	—	2,176	7,254
Fixed income										
Corporate debt	—	1,614	251	—	1,865	—	1,614	251	—	1,865
U.S. Treasury and agencies	1,917	52	—	—	1,969	1,917	52	—	—	1,969
Foreign governments	—	82	—	—	82	—	82	—	—	82
State and municipal debt	—	263	—	—	263	—	263	—	—	263
Other[c]	—	47	—	510	557	—	47	—	510	557
Fixed income subtotal	1,917	2,058	251	510	4,736	1,917	2,058	251	510	4,736
Middle market lending	—	—	397	131	528	—	—	397	131	528
Private equity	—	—	—	222	222	—	—	—	222	222
Real estate	—	—	—	471	471	—	—	—	471	471
NDT fund investments subtotal[d]	6,215	3,058	648	3,510	13,431	6,215	3,058	648	3,510	13,431
Pledged assets for Zion Station decommissioning										
Cash equivalents	2	—	—	—	2	2	—	—	—	2
Equities	—	1	—	—	1	—	1	—	—	1
Middle market lending	—	—	12	24	36	—	—	12	24	36
Pledged assets for Zion Station decommissioning subtotal[e]	2	1	12	24	39	2	1	12	24	39
Rabbi trust investments										
Cash equivalents	5	—	—	—	5	77	—	—	—	77
Mutual funds	23	—	—	—	23	58	—	—	—	58
Fixed income	—	—	—	—	—	—	12	—	—	12
Life insurance contracts	—	22	—	—	22	—	71	22	—	93
Rabbi trust investments subtotal[f]	28	22	—	—	50	135	83	22	—	240
Commodity derivative assets										
Economic hedges	557	2,378	1,290	—	4,225	557	2,378	1,290	—	4,225
Proprietary trading	2	31	35	—	68	2	31	35	—	68
Effect of netting and allocation of collateral[g][h]	(585)	(1,769)	(635)	—	(2,989)	(585)	(1,769)	(635)	—	(2,989)
Commodity derivative assets subtotal	(26)	640	690	—	1,304	(26)	640	690	—	1,304

103

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	Generation					Exelon				
As of December 31, 2017	Level 1	Level 2	Level 3	Not subject to leveling	Total	Level 1	Level 2	Level 3	Not subject to leveling	Total
Interest rate and foreign currency derivative assets										
Derivatives designated as hedging instruments	—	3	—	—	3	—	6	—	—	6
Economic hedges	—	10	—	—	10	—	10	—	—	10
Effect of netting and allocation of collateral	(2)	(5)	—	—	(7)	(2)	(5)	—	—	(7)
Interest rate and foreign currency derivative assets subtotal	(2)	8	—	—	6	(2)	11	—	—	9
Other investments	—	—	37	—	37	—	—	37	—	37
Total assets	6,385	3,729	1,387	3,534	15,035	6,980	3,793	1,409	3,534	15,716
Liabilities										
Commodity derivative liabilities										
Economic hedges	(712)	(2,226)	(845)	—	(3,783)	(713)	(2,226)	(1,101)	—	(4,040)
Proprietary trading	(2)	(42)	(9)	—	(53)	(2)	(42)	(9)	—	(53)
Effect of netting and allocation of collateral[(g) (h)]	650	2,089	716	—	3,455	651	2,089	716	—	3,456
Commodity derivative liabilities subtotal	(64)	(179)	(138)	—	(381)	(64)	(179)	(394)	—	(637)
Interest rate and foreign currency derivative liabilities										
Derivatives designated as hedging instruments	—	(2)	—	—	(2)	—	(2)	—	—	(2)
Economic hedges	(1)	(8)	—	—	(9)	(1)	(8)	—	—	(9)
Effect of netting and allocation of collateral	2	5	—	—	7	2	5	—	—	7
Interest rate and foreign currency derivative liabilities subtotal	1	(5)	—	—	(4)	1	(5)	—	—	(4)
Deferred compensation obligation	—	(38)	—	—	(38)	—	(145)	—	—	(145)
Total liabilities	(63)	(222)	(138)	—	(423)	(63)	(329)	(394)	—	(786)
Total net assets	$6,322	$3,507	$1,249	$3,534	$14,612	$6,917	$3,464	$1,015	$3,534	$14,930

(a) Generation excludes cash of $204 million and $259 million at June 30, 2018 and December 31, 2017 and restricted cash of $45 million and $127 million at June 30, 2018 and December 31, 2017. Exelon excludes cash of $296 million and $389 million at June 30, 2018 and December 31, 2017 and restricted cash of $72 million and $145 million at June 30, 2018 and December 31, 2017 and includes long-term restricted cash of $128 million and $85 million at June 30, 2018 and December 31, 2017, which is reported in Other deferred debits on the Consolidated Balance Sheets.

(b) Includes $48 million and $77 million of cash received from outstanding repurchase agreements at June 30, 2018 and December 31, 2017, respectively, and is offset by an obligation to repay upon settlement of the agreement as discussed in (d) below.

(c) Includes derivative instruments of less than $1 million and less than $1 million, which have a total notional amount of $965 million and $811 million at June 30, 2018 and December 31, 2017, respectively. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the fiscal years ended and do not represent the amount of Exelon and Generation's exposure to credit or market loss.

(d) Excludes net liabilities of $103 million and $82 million at June 30, 2018 and December 31, 2017, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, repurchase agreement obligations, and payables related to pending securities purchases. The repurchase agreements are generally short-term in nature with durations generally of 30 days or less.

(e) Excludes net assets of less than $1 million at June 30, 2018. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.

(f) The amount of unrealized gains/(losses) at Generation totaled less than $1 million and less than $1 million for the three months ended June 30, 2018 and June 30, 2017, respectively. The amount of unrealized gains/(losses) at Generation totaled less than $1

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

million and $1 million for the six months ended June 30, 2018 and June 30, 2017, respectively. The amount of unrealized gains/(losses) at Exelon totaled less than $1 million and $1 million for the three months ended June 30, 2018 and June 30, 2017, respectively. The amount of unrealized gains/(losses) at Exelon totaled $1 million and $3 million for the six months ended June 30, 2018 and June 30, 2017, respectively.

(g) Collateral posted/(received) from counterparties totaled $36 million, $208 million and $138 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of June 30, 2018. Collateral posted/(received) from counterparties, net of collateral paid to counterparties, totaled $65 million, $320 million and $81 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2017.

(h) Of the collateral posted/(received), $11 million represents variation margin on the exchanges as of June 30, 2018. Of the collateral posted/(received), $(117) million represents variation margin on the exchanges as of December 31, 2017.

Exelon and Generation hold investments without readily determinable fair values with carrying amounts of $68 million as of June 30, 2018. Changes were immaterial in fair value, cumulative adjustments and impairments for the three and six months ended June 30, 2018.

ComEd, PECO and BGE

The following tables present assets and liabilities measured and recorded at fair value on ComEd's, PECO's and BGE's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of June 30, 2018 and December 31, 2017:

	ComEd				PECO				BGE			
As of June 30, 2018	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets												
Cash equivalents[(a)]	$113	$ —	$—	$113	$5	$ —	$ —	$5	$—	$ —	$ —	$ —
Rabbi trust investments												
Cash equivalents	—	—	—	—	—	—	—	—	—	—	—	—
Mutual funds	—	—	—	—	7	—	—	7	6	—	—	6
Life insurance contracts	—	—	—	—	—	10	—	10	—	—	—	—
Rabbi trust investments subtotal[(b)]	—	—	—	—	7	10	—	17	6	—	—	6
Total assets	113	—	—	113	12	10	—	22	6	—	—	6
Liabilities												
Deferred compensation obligation	—	(7)	—	(7)	—	(9)	—	(9)	—	(4)	—	(4)
Mark-to-market derivative liabilities[(c)]	—	—	(252)	(252)	—	—	—	—	—	—	—	—
Total liabilities	—	(7)	(252)	(259)	—	(9)	—	(9)	—	(4)	—	(4)
Total net assets (liabilities)	$113	$ (7)	$(252)	$(146)	$12	$ 1	$ —	$13	$6	$ (4)	$ —	$ 2

105

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	ComEd				PECO				BGE			
As of December 31, 2017	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets												
Cash equivalents[(a)]	$98	$ —	$—	$98	$228	$ —	$ —	$228	$—	$ —	$ —	$ —
Rabbi trust investments												
Mutual funds	—	—	—	—	7	—	—	7	6	—	—	6
Life insurance contracts	—	—	—	—	—	10	—	10	—	—	—	—
Rabbi trust investments subtotal[(b)]	—	—	—	—	7	10	—	17	6	—	—	6
Total assets	98	—	—	98	235	10	—	245	6	—	—	6
Liabilities												
Deferred compensation obligation	—	(8)	—	(8)	—	(11)	—	(11)	—	(5)	—	(5)
Mark-to-market derivative liabilities[(c)]	—	—	(256)	(256)	—	—	—	—	—	—	—	—
Total liabilities	—	(8)	(256)	(264)	—	(11)	—	(11)	—	(5)	—	(5)
Total net assets (liabilities)	$98	$ (8)	$(256)	$(166)	$235	$ (1)	$ —	$234	$6	$ (5)	$ —	$ 1

(a) ComEd excludes cash of $30 million and $45 million at June 30, 2018 and December 31, 2017 and includes long-term restricted cash of $108 million and $62 million at June 30, 2018 and December 31, 2017, which is reported in Other deferred debits on the Consolidated Balance Sheets. PECO excludes cash of $18 million and $47 million at June 30, 2018 and December 31, 2017. BGE excludes cash of $7 million and $17 million at June 30, 2018 and December 31, 2017 and restricted cash of $1 million and $1 million at June 30, 2018 and December 31, 2017.

(b) The amount of unrealized gains/(losses) at ComEd, PECO and BGE totaled less than $1 million for the three and six months ended June 30, 2018 and June 30, 2017, respectively.

(c) The Level 3 balance consists of the current and noncurrent liability of $23 million and $229 million, respectively, at June 30, 2018, and $21 million and $235 million, respectively, at December 31, 2017, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

PHI, Pepco, DPL and ACE
The following tables present assets and liabilities measured and recorded at fair value on PHI's, Pepco's, DPL's and ACE's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of June 30, 2018 and December 31, 2017:

	As of June 30, 2018				As of December 31, 2017			
PHI	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
Cash equivalents[a]	$235	$ —	$ —	$235	$83	$ —	$ —	$83
Rabbi trust investments								
Cash equivalents	39	—	—	39	72	—	—	72
Mutual funds	15	—	—	15	—	—	—	—
Fixed income	—	18	—	18	—	12	—	12
Life insurance contracts	—	23	36	59	—	23	22	45
Rabbi trust investments subtotal[b]	54	41	36	131	72	35	22	129
Total assets	289	41	36	366	155	35	22	212
Liabilities								
Deferred compensation obligation	—	(22)	—	(22)	—	(25)	—	(25)
Mark-to-market derivative liabilities[c]	—	—	—	—	(1)	—	—	(1)
Effect of netting and allocation of collateral	—	—	—	—	1	—	—	1
Mark-to-market derivative liabilities subtotal	—	—	—	—	—	—	—	—
Total liabilities	—	(22)	—	(22)	—	(25)	—	(25)
Total net assets	$289	$ 19	$ 36	$344	$155	$ 10	$ 22	$187

	Pepco				DPL				ACE			
As of June 30, 2018	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets												
Cash equivalents[a]	$73	$ —	$ —	$73	$137	$ —	$ —	$137	$25	$ —	$ —	$ 25
Rabbi trust investments												
Cash equivalents	38	—	—	38	—	—	—	—	—	—	—	—
Fixed income	—	7	—	7	—	—	—	—	—	—	—	—
Life insurance contracts	—	23	36	59	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal[b]	38	30	36	104	—	—	—	—	—	—	—	—
Total assets	111	30	36	177	137	—	—	137	25	—	—	25
Liabilities												
Deferred compensation obligation	—	(4)	—	(4)	—	(1)	—	(1)	—	—	—	—
Total liabilities	—	(4)	—	(4)	—	(1)	—	(1)	—	—	—	—
Total net assets (liabilities)	$111	$ 26	$ 36	$173	$137	$ (1)	$ —	$136	$25	$ —	$ —	$ 25

107

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	Pepco				DPL				ACE			
As of December 31, 2017	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets												
Cash equivalents[(a)]	$36	$ —	$ —	$36	$—	$ —	$ —	$ —	$29	$ —	$ —	$ 29
Rabbi trust investments												
Cash equivalents	44	—	—	44	—	—	—	—	—	—	—	—
Fixed income	—	12	—	12	—	—	—	—	—	—	—	—
Life insurance contracts	—	23	22	45	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal[(b)]	44	35	22	101	—	—	—	—	—	—	—	—
Total assets	80	35	22	137	—	—	—	—	29	—	—	29
Liabilities												
Deferred compensation obligation	—	(4)	—	(4)	—	(1)	—	(1)	—	—	—	—
Mark-to-market derivative liabilities[(c)]	—	—	—	—	(1)	—	—	(1)	—	—	—	—
Effect of netting and allocation of collateral	—	—	—	—	1	—	—	1	—	—	—	—
Mark-to-market derivative liabilities subtotal	—	—	—	—	—	—	—	—	—	—	—	—
Total liabilities	—	(4)	—	(4)	—	(1)	—	(1)	—	—	—	—
Total net assets (liabilities)	$80	$ 31	$ 22	$133	$—	$ (1)	$ —	$ (1)	$29	$ —	$ —	$ 29

(a) PHI excludes cash of $18 million and $12 million at June 30, 2018 and December 31, 2017, respectively, and includes long-term restricted cash of $20 million and $23 million at June 30, 2018 and December 31, 2017, respectively, which is reported in Other deferred debits on the Consolidated Balance Sheets. Pepco excludes cash of $7 million and $4 million at June 30, 2018 and December 31, 2017, respectively. DPL excludes cash of $4 million and $2 million at June 30, 2018 and December 31, 2017, respectively. ACE excludes cash of $6 million and $2 million at June 30, 2018 and December 31, 2017, respectively, and includes long-term restricted cash of $20 million and $23 million at June 30, 2018 and December 31, 2017, respectively, which is reported in Other deferred debits on the Consolidated Balance Sheets.

(b) The amount of unrealized gains/(losses) at PHI and Pepco totaled $1 million and less than $1 million for the three and six months ended June 30, 2018 and June 30, 2017, respectively. The amount of unrealized gains/(losses) at DPL and ACE totaled less than $1 million for the three and six months ended June 30, 2018 and June 30, 2017, respectively.

(c) Represents natural gas futures purchased by DPL as part of a natural gas hedging program approved by the DPSC.

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the three and six months ended June 30, 2018 and 2017:

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Three Months Ended June 30, 2018	Generation NDT Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total Generation	ComEd Mark-to-Market Derivatives	PHI Life Insurance Contracts[c]	Eliminated in Consolidation	Exelon Total
Balance as of March 31, 2018	$609	$ 16	$ 918	$ 36	$ 1,579	$ (267)	$ 23	$ —	$ 1,335
Total realized / unrealized gains (losses)									
Included in net income	—	—	(113) [a]	—	(113)	—	1	—	(112)
Included in noncurrent payables to affiliates	(3)	—	—	—	(3)	—	—	3	—
Included in payable for Zion Station decommissioning	—	2	—	—	2	—	—	—	2
Included in regulatory assets/liabilities	—	—	—	—	—	15 [b]	—	(3)	12
Change in collateral	—	—	(49)	—	(49)	—	—	—	(49)
Purchases, sales, issuances and settlements									
Purchases	17	—	13	—	30	—	—	—	30
Sales	—	—	(1)	—	(1)	—	—	—	(1)
Settlements	(38)	—	—	—	(38)	—	12 [d]	—	(26)
Transfers into Level 3	—	—	(15)	—	(15)	—	—	—	(15)
Transfers out of Level 3	—	—	(16)	—	(16)	—	—	—	(16)
Balance at June 30, 2018	$585	$ 18	$ 737	$ 36	$ 1,376	$ (252)	$ 36	$ —	$ 1,160
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of June 30, 2018	$(4)	$ —	$ 7	$ —	$ 3	$ —	$ —	$ —	$ 3

109

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	Generation					ComEd	PHI		Exelon
Six Months Ended June 30, 2018	NDT Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total Generation	Mark-to-Market Derivatives	Life Insurance Contracts[(c)]	Eliminated in Consolidation	Mark-to-Market Derivatives
Balance as of December 31, 2017	$648	$ 12	$ 552	$ 37	$ 1,249	$ (256)	$ 22	$ —	$ 1,015
Total realized / unrealized gains (losses)									
Included in net income	1	—	71 [(a)]	1	73	—	2	—	75
Included in noncurrent payables to affiliates	3	—	—	—	3	—	—	(3)	—
Included in payable for Zion Station decommissioning	—	5	—	—	5	—	—	—	5
Included in regulatory assets	—	—	—	—	—	4 [(b)]	—	3	7
Change in collateral	—	—	57	—	57	—	—	—	57
Purchases, sales, issuances and settlements									
Purchases	19	1	100	—	120	—	—	—	120
Sales	—	—	(4)	—	(4)	—	—	—	(4)
Settlements	(86)	—	—	—	(86)	—	12 [(d)]	—	(74)
Transfers into Level 3	—	—	(23)	—	(23)	—	—	—	(23)
Transfers out of Level 3	—	—	(16)	(2)	(18)	—	—	—	(18)
Balance as of June 30, 2018	$585	$ 18	$ 737	$ 36	$ 1,376	$ (252)	$ 36	$ —	$ 1,160
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of June 30, 2018	$(4)	$ —	$ 263	$ 1	$ 260	$ —	$ —	$ —	$ 260

(a) Includes a reduction for the reclassification of $120 million and $192 million of realized gains due to the settlement of derivative contracts for the three and six months ended June 30, 2018, respectively.

(b) Includes $11 million of increases in fair value and an increase for realized losses due to settlements of $4 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended June 30, 2018. Includes $6 million of decreases in fair value and an increase for realized losses due to settlements of $10 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the six months ended June 30, 2018.

(c) The amounts represented are life insurance contracts at Pepco.

(d) The settlement amount represents the full payment of a loan held against one of Pepco's life insurance policy contracts.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	Generation					ComEd	PHI		Exelon
Three Months Ended June 30, 2017	NDT Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total Generation	Mark-to-Market Derivatives	Life Insurance Contracts	Eliminated in Consolidation [c]	Total
Balance as of March 31, 2017	$683	$ 20	$ 565	$ 40	$ 1,308	$ (282)	$ 20	$ —	$ 1,046
Total realized / unrealized gains (losses)									
Included in net income	1	—	(3) [a]	—	(2)	—	—	—	(2)
Included in noncurrent payables to affiliates	4	—	—	—	4	—	—	(4)	—
Included in payable for Zion Station decommissioning	—	1	—	—	1	—	—	—	1
Included in regulatory assets	—	—	—	—	—	26 [b]	—	4	30
Change in collateral	—	—	31	—	31	—	—	—	31
Purchases, sales, issuances and settlements									
Purchases	19	—	21	1	41	—	—	—	41
Sales	—	—	(13)	—	(13)	—	—	—	(13)
Settlements	(24)	—	—	—	(24)	—	—	—	(24)
Transfers into Level 3	—	—	(8)	—	(8)	—	—	—	(8)
Transfers out of Level 3	—	—	(4)	—	(4)	—	—	—	(4)
Balance as of June 30, 2017	$683	$ 21	$ 589	$ 41	$ 1,334	$ (256)	$ 20	$ —	$ 1,098
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of June 30, 2017	$—	$ —	$ 43	$ —	$ 43	$ —	$ —	$ —	$43

111

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Six Months Ended June 30, 2017	Generation					ComEd	PHI		Exelon
	NDT Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total Generation	Mark-to-Market Derivatives	Life Insurance Contracts [(c)]	Eliminated in Consolidation	Total
Balance as of December 31, 2016	$677	$ 19	$ 493	$ 42	$ 1,231	$ (258)	$ 20	$ —	$993
Total realized / unrealized gains (losses)									
Included in net income	4	—	(46) [(a)]	1	(41)	—	1	—	(40)
Included in noncurrent payables to affiliates	13	—	—	—	13	—	—	(13)	—
Included in payable for Zion Station decommissioning	—	1	—	—	1	—	—	—	1
Included in regulatory assets	—	—	—	—	—	2 [(b)]	—	13	15
Change in collateral	—	—	69	—	69	—	—	—	69
Purchases, sales, issuances and settlements									
Purchases	36	1	90	3	130	—	—	—	130
Sales	—	—	(15)	—	(15)	—	—	—	(15)
Issuances	—	—	—	—	—	—	(1)	—	(1)
Settlements	(47)	—	—	—	(47)	—	—	—	(47)
Transfers into Level 3	—	—	(10)	—	(10)	—	—	—	(10)
Transfers out of Level 3	—	—	8	(5)	3	—	—	—	3
Balance as of June 30, 2017	$683	$ 21	$ 589	$ 41	$ 1,334	$ (256)	$ 20	$ —	$1,098
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of June 30, 2017	$2	$ —	$ 102	$ 1	$ 105	$ —	$ 1	$ —	$106

(a) Includes a reduction for the reclassification of $46 million and $148 million of realized gains due to the settlement of derivative contracts for the three and six months ended June 30, 2017, respectively.

(b) Includes $25 million of increases in fair value and an increase for realized losses due to settlements of $1 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended June 30, 2017. Includes $5 million of decreases in fair value and an increase for realized losses due to settlements of $7 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the six months ended June 30, 2017.

(c) The amounts represented are life insurance contracts at Pepco.

112

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the three and six months ended June 30, 2018 and 2017:

	Generation			PHI	Exelon			
	Operating Revenues	Purchased Power and Fuel	Other, net[a]	Operating and Maintenance[a]	Operating Revenues	Purchased Power and Fuel	Operating and Maintenance	Other, net[a]
Total gains (losses) included in net income for the three months ended June 30, 2018	$(191)	$ 78	$ —	$ 1	$(191)	$ 78	$ 1	$ —
Total gains (losses) included in net income for the six months ended June 30, 2018	144	(73)	2	2	144	(73)	2	2
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended June 30, 2018	(71)	78	(4)	—	(71)	78	—	(4)
Change in the unrealized gains (losses) relating to assets and liabilities held for the six months ended June 30, 2018	238	25	(3)	—	238	25	—	(3)

	Generation			PHI	Exelon		
	Operating Revenues	Purchased Power and Fuel	Other, net[a]	Other, net[a]	Operating Revenues	Purchased Power and Fuel	Other, net[a]
Total gains (losses) included in net income for the three months ended June 30, 2017	$(51)	$ 48	$ 1	$ —	$(51)	$ 48	$ 1
Total gains (losses) included in net income for the six months ended June 30, 2017	37	(83)	5	1	37	(83)	6
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended June 30, 2017	—	43	—	—	—	43	—
Change in the unrealized gains (losses) relating to assets and liabilities held for the six months ended June 30, 2017	140	(38)	3	1	140	(38)	4

(a) Other, net activity consists of realized and unrealized gains (losses) included in income for the NDT funds held by Generation, accrued interest on a convertible promissory note at Generation and the life insurance contracts held by PHI and Pepco.

Valuation Techniques Used to Determine Fair Value

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above.

Cash Equivalents (Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE). The Registrants' cash equivalents include investments with original maturities of three months or less when purchased. The cash equivalents shown in the fair value tables are comprised of investments in mutual and money market funds. The fair values of the shares of these funds are based on observable market prices and, therefore, have been categorized in Level 1 in the fair value hierarchy.

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). The trust fund investments have been established to satisfy Generation's and CENG's nuclear decommissioning obligations as required by the NRC. The NDT funds hold debt and equity securities directly and indirectly through commingled funds and mutual funds, which are included in Equities and Fixed Income. Generation’s and CENG's NDT fund investments policies outline investment guidelines for the trusts and limit the trust funds’ exposures to investments in highly

113

Table of Contents

illiquid markets and other alternative investments. Investments with maturities of three months or less when purchased, including certain short-term fixed income securities are considered cash equivalents and included in the recurring fair value measurements hierarchy as Level 1 or Level 2.

With respect to individually held equity securities, the trustees obtain prices from pricing services, whose prices are generally obtained from direct feeds from market exchanges, which Generation is able to independently corroborate. The fair values of equity securities held directly by the trust funds which are based on quoted prices in active markets are categorized in Level 1. Certain equity securities have been categorized as Level 2 because they are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities. Equity securities held individually are primarily traded on the New York Stock Exchange and NASDAQ-Global Select Market, which contain only actively traded securities due to the volume trading requirements imposed by these exchanges.

For fixed income securities, multiple prices from pricing services are obtained whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class or issue for each security. With respect to individually held fixed income securities, the trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine that another price source is considered to be preferable. Generation has obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, Generation selectively corroborates the fair values of securities by comparison to other market-based price sources. U.S. Treasury securities are categorized as Level 1 because they trade in a highly liquid and transparent market. The fair values of fixed income securities, excluding U.S. Treasury securities, are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities, adjusted for observable differences and are categorized in Level 2. The fair values of private placement fixed income securities, which are included in Corporate debt, are determined using a third-party valuation that contains significant unobservable inputs and are categorized in Level 3.

Equity and fixed income commingled funds and mutual funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives such as holding short-term fixed income securities or tracking the performance of certain equity indices by purchasing equity securities to replicate the capitalization and characteristics of the indices. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For commingled funds and mutual funds, which are not publicly quoted, the funds are valued using NAV as a practical expedient for fair value, which is primarily derived from the quoted prices in active markets on the underlying securities, and are not classified within the fair value hierarchy. These investments typically can be redeemed monthly with 30 or less days of notice and without further restrictions.

Derivative instruments consisting primarily of futures and interest rate swaps to manage risk are recorded at fair value. Over the counter derivatives are valued daily based on quoted prices in active markets and trade in open markets and have been categorized as Level 1. Derivative instruments other than over the counter derivatives are valued based on external price data of comparable securities and have been categorized as Level 2.

Middle market lending are investments in loans or managed funds which lend to private companies. Generation elected the fair value option for its investments in certain limited partnerships that invest in middle market lending managed funds. The fair value of these loans is determined using a combination of valuation models including cost models, market models and income models. Investments in loans are categorized as Level 3 because the fair value of these securities is based largely on inputs that are unobservable and utilize complex valuation models. Managed funds are valued using NAV or its

equivalent as a practical expedient, and therefore, are not classified within the fair value hierarchy. Investments in middle market lending typically cannot be redeemed until maturity of the term loan.

Private equity and real estate investments include those in limited partnerships that invest in operating companies and real estate holding companies that are not publicly traded on a stock exchange, such as, leveraged buyouts, growth capital, venture capital, distressed investments, investments in natural resources, and direct investments in pools of real estate properties. The fair value of private equity and real estate investments is determined using NAV or its equivalent as a practical expedient, and therefore, are not classified within the fair value hierarchy. These investments typically cannot be redeemed and are generally liquidated over a period of 8 to 10 years from the initial investment date. Private equity and real estate valuations are reported by the fund manager and are based on the valuation of the underlying investments, which include inputs such as cost, operating results, discounted future cash flows, market based comparable data, and independent appraisals from sources with professional qualifications. These valuation inputs are unobservable.

As of June 30, 2018, Generation has outstanding commitments to invest in fixed income, middle market lending, private equity and real estate investments of approximately \$62 million, \$302 million, \$178 million, and \$100 million, respectively. These commitments will be funded by Generation's existing nuclear decommissioning trust funds.

Concentrations of Credit Risk. Generation evaluated its NDT portfolios for the existence of significant concentrations of credit risk as of June 30, 2018. Types of concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, type of industry, foreign country, and individual fund. As of June 30, 2018, there were no significant concentrations (generally defined as greater than 10 percent) of risk in Generation's NDT assets.

See Note 13 — Nuclear Decommissioning for additional information on the NDT fund investments.

Rabbi Trust Investments (Exelon, Generation, PECO, BGE, PHI, Pepco, DPL and ACE). The Rabbi trusts were established to hold assets related to deferred compensation plans existing for certain active and retired members of Exelon's executive management and directors. The Rabbi trusts assets are included in investments in the Registrants' Consolidated Balance Sheets and consist primarily of money market funds, mutual funds, fixed income securities and life insurance policies. The mutual funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. Money market funds and mutual funds are publicly quoted and have been categorized as Level 1 given the clear observability of the prices. The fair values of fixed income securities are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities, adjusted for observable differences and are categorized in Level 2. The life insurance policies are valued using the cash surrender value of the policies, net of loans against those policies, which is provided by a third-party. Certain life insurance policies, which consist primarily of mutual funds that are priced based on observable market data, have been categorized as Level 2 because the life insurance policies can be liquidated at the reporting date for the value of the underlying assets. Life insurance policies that are valued using unobservable inputs have been categorized as Level 3.

Mark-to-Market Derivatives (Exelon, Generation, ComEd, PHI and DPL). Derivative contracts are traded in both exchange-based and non-exchange-based markets. Exchange-based derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy. Certain derivatives' pricing is verified using indicative price quotations available through brokers or over-the-counter, on-line exchanges and are categorized in Level 2. These price quotations reflect the average of the bid-ask, mid-point prices and are obtained from sources that the Registrants believe provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. This includes consideration of actual transaction volumes, market delivery points,

Table of Contents

bid-ask spreads and contract duration. The remainder of derivative contracts are valued using the Black model, an industry standard option valuation model. The Black model takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the future prices of energy, interest rates, volatility, credit worthiness and credit spread. For derivatives that trade in liquid markets, such as generic forwards, swaps and options, model inputs are generally observable. Such instruments are categorized in Level 2. The Registrants' derivatives are predominantly at liquid trading points. For derivatives that trade in less liquid markets with limited pricing information model inputs generally would include both observable and unobservable inputs. These valuations may include an estimated basis adjustment from an illiquid trading point to a liquid trading point for which active price quotations are available. Such instruments are categorized in Level 3.

Exelon may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve its targeted level of variable-rate debt as a percent of total debt. In addition, the Registrants may utilize interest rate derivatives to lock in interest rate levels in anticipation of future financings. These interest rate derivatives are typically designated as cash flow hedges. Exelon determines the current fair value by calculating the net present value of expected payments and receipts under the swap agreement, based on and discounted by the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and other market parameters. As these inputs are based on observable data and valuations of similar instruments, the interest rate swaps are categorized in Level 2 in the fair value hierarchy. See Note 10 — Derivative Financial Instruments for additional information on mark-to-market derivatives.

Deferred Compensation Obligations (Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE). The Registrants' deferred compensation plans allow participants to defer certain cash compensation into a notional investment account. The Registrants include such plans in other current and noncurrent liabilities in their Consolidated Balance Sheets. The value of the Registrants' deferred compensation obligations is based on the market value of the participants' notional investment accounts. The underlying notional investments are comprised primarily of equities, mutual funds, commingled funds, and fixed income securities which are based on directly and indirectly observable market prices. Since the deferred compensation obligations themselves are not exchanged in an active market, they are categorized as Level 2 in the fair value hierarchy.

The value of certain employment agreement obligations (which are included with the Deferred Compensation Obligation in the tables above) are based on a known and certain stream of payments to be made over time and are categorized as Level 2 within the fair value hierarchy.

Additional Information Regarding Level 3 Fair Value Measurements (Exelon, Generation, ComEd, PHI, Pepco, DPL and ACE)

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). For middle market lending and certain corporate debt securities investments, the fair value is determined using a combination of valuation models including cost models, market models and income models. The valuation estimates are based on discounting the forecasted cash flows, market-based comparable data, credit and liquidity factors, as well as other factors that may impact value. Significant judgment is required in the application of discounts or premiums applied for factors such as size, marketability, credit risk and relative performance.

Because Generation relies on third-party fund managers to develop the quantitative unobservable inputs without adjustment for the valuations of its Level 3 investments, quantitative information about significant unobservable inputs used in valuing these investments is not reasonably available to Generation. This includes information regarding the sensitivity of the fair values to changes in the unobservable inputs. Generation gains an understanding of the fund managers' inputs and assumptions used in preparing the valuations. Generation performed procedures to assess the reasonableness of the valuations.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Rabbi Trust Investments - Life insurance contracts (Exelon, PHI, Pepco, DPL and ACE). For life insurance policies categorized as Level 3, the fair value is determined based on the cash surrender value of the policy, which contains unobservable inputs and assumptions. Because Exelon relies on its third-party insurance provider to develop the inputs without adjustment for the valuations of its Level 3 investments, quantitative information about significant unobservable inputs used in valuing these investments is not reasonably available to Exelon. Exelon gains an understanding of the types of inputs and assumptions used in preparing the valuations and performs procedures to assess the reasonableness of the valuations.

Mark-to-Market Derivatives (Exelon, Generation and ComEd). For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief executive officer and includes the chief risk officer, chief strategy officer, chief executive officer of Exelon Utilities, chief commercial officer, chief financial officer and chief executive officer of Constellation. The RMC reports to the Finance and Risk Committee of the Exelon Board of Directors on the scope of the risk management activities. Forward price curves for the power market utilized by the front office to manage the portfolio, are reviewed and verified by the middle office, and used for financial reporting by the back office. The Registrants consider credit and nonperformance risk in the valuation of derivative contracts categorized in Level 2 and 3, including both historical and current market data in its assessment of credit and nonperformance risk by counterparty. Due to master netting agreements and collateral posting requirements, the impacts of credit and nonperformance risk were not material to the financial statements.

Disclosed below is detail surrounding the Registrants' significant Level 3 valuations. The calculated fair value includes marketability discounts for margining provisions and other attributes. Generation's Level 3 balance generally consists of forward sales and purchases of power and natural gas and certain transmission congestion contracts. Generation utilizes various inputs and factors including market data and assumptions that market participants would use in pricing assets or liabilities as well as assumptions about the risks inherent in the inputs to the valuation technique. The inputs and factors include forward commodity prices, commodity price volatility, contractual volumes, delivery location, interest rates, credit quality of counterparties and credit enhancements.

For commodity derivatives, the primary input to the valuation models is the forward commodity price curve for each instrument. Forward commodity price curves are derived by risk management for liquid locations and by the traders and portfolio managers for illiquid locations. All locations are reviewed and verified by risk management considering published exchange transaction prices, executed bilateral transactions, broker quotes, and other observable or public data sources. The relevant forward commodity curve used to value each of the derivatives depends on a number of factors, including commodity type, delivery location, and delivery period. Price volatility varies by commodity and location. When appropriate, Generation discounts future cash flows using risk free interest rates with adjustments to reflect the credit quality of each counterparty for assets and Generation's own credit quality for liabilities. The level of observability of a forward commodity price varies generally due to the delivery location and delivery period. Certain delivery locations including PJM West Hub (for power) and Henry Hub (for natural gas) are more liquid and prices are observable for up to three years in the future. The observability period of volatility is generally shorter than the underlying power curve used in option valuations. The forward curve for a less liquid location is estimated by using the forward curve from the liquid location and applying a spread to represent the cost to transport the commodity to the delivery location. This spread does not

117

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

typically represent a majority of the instrument's market price. As a result, the change in fair value is closely tied to liquid market movements and not a change in the applied spread. The change in fair value associated with a change in the spread is generally immaterial. An average spread calculated across all Level 3 power and gas delivery locations is approximately $3.17 and $0.47 for power and natural gas, respectively. Many of the commodity derivatives are short-term in nature and thus a majority of the fair value may be based on observable inputs even though the contract as a whole must be classified as Level 3.

On December 17, 2010, ComEd entered into several 20-year floating to fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. See Note 10 —Derivative Financial Instruments for additional information. The fair value of these swaps has been designated as a Level 3 valuation due to the long tenure of the positions and internal modeling assumptions. The modeling assumptions include using natural gas heat rates to project long term forward power curves adjusted by a renewable factor that incorporates time of day and seasonality factors to reflect accurate renewable energy pricing. In addition, marketability reserves are applied to the positions based on the tenor and supplier risk.

The table below discloses the significant inputs to the forward curve used to value these positions.

Type of trade	Fair Value at June 30, 2018	Valuation Technique	Unobservable Input	Range	
Mark-to-market derivatives — Economic Hedges (Exelon and Generation)[(a)(b)]	$ 536	Discounted Cash Flow	Forward power price	$9	-$141
			Forward gas price	$1.04	-$11.19
		Option Model	Volatility percentage	9%	-435%
Mark-to-market derivatives — Proprietary trading (Exelon and Generation)[(a)(b)]	$ 63	Discounted Cash Flow	Forward power price	$9	-$139
Mark-to-market derivatives (Exelon and ComEd)	$ (252)	Discounted Cash Flow	Forward heat rate[(c)]	10x	-11x
			Marketability reserve	4%	-8%
			Renewable factor	88%	-120%

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Type of trade	Fair Value at December 31, 2017	Valuation Technique	Unobservable Input	Range	
Mark-to-market derivatives — Economic Hedges (Exelon and Generation)[(a)(b)]	$ 445	Discounted Cash Flow	Forward power price	$3	-$124
			Forward gas price	$1.27	-$12.80
		Option Model	Volatility percentage	11%	-139%
Mark-to-market derivatives — Proprietary trading (Exelon and Generation)[(a)(b)]	$ 26	Discounted Cash Flow	Forward power price	$14	-$94
Mark-to-market derivatives (Exelon and ComEd)	$ (256)	Discounted Cash Flow	Forward heat rate[(c)]	9x	-10x
			Marketability reserve	4%	-8%
			Renewable factor	88%	-120%

(a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
(b) The fair values do not include cash collateral posted on level three positions of $138 million and $81 million as of June 30, 2018 and December 31, 2017, respectively.
(c) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract’s delivery.

The inputs listed above would have a direct impact on the fair values of the above instruments if they were adjusted. The significant unobservable inputs used in the fair value measurement of Generation’s commodity derivatives are forward commodity prices and for options is price volatility. Increases (decreases) in the forward commodity price in isolation would result in significantly higher (lower) fair values for long positions (contracts that give Generation the obligation or option to purchase a commodity), with offsetting impacts to short positions (contracts that give Generation the obligation or right to sell a commodity). Increases (decreases) in volatility would increase (decrease) the value for the holder of the option (writer of the option). Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of volatility of prices. An increase to the reserves listed above would decrease the fair value of the positions. An increase to the heat rate or renewable factors would increase the fair value accordingly. Generally, interrelationships exist between market prices of natural gas and power. As such, an increase in natural gas pricing would potentially have a similar impact on forward power markets.

10. Derivative Financial Instruments (All Registrants)

The Registrants use derivative instruments to manage commodity price risk, interest rate risk and foreign exchange risk related to ongoing business operations.

Commodity Price Risk (All Registrants)

To the extent the amount of energy Generation produces differs from the amount of energy it has contracted to sell, Exelon and Generation are exposed to market fluctuations in the prices of electricity, fossil fuels and other commodities. Each of the Registrants employ established policies and procedures to manage their risks associated with market fluctuations in commodity prices by entering into physical and financial derivative contracts, including swaps, futures, forwards, options and short-term and long-

Table of Contents

term commitments to purchase and sell energy and commodity products. The Registrants believe these instruments, which are either determined to be non-derivative or classified as economic hedges, mitigate exposure to fluctuations in commodity prices.

Derivative authoritative guidance requires that derivative instruments be recognized as either assets or liabilities at fair value, with changes in fair value of the derivative recognized in earnings immediately. Other accounting treatments are available through special election and designation, provided they meet specific, restrictive criteria both at the time of designation and on an ongoing basis. These alternative permissible accounting treatments include normal purchase normal sale (NPNS), cash flow hedges and fair value hedges. For Generation, all derivative economic hedges related to commodities are recorded at fair value through earnings for the consolidated company, referred to as economic hedges in the following tables. Additionally, Generation is exposed to certain market risks through its proprietary trading activities. The proprietary trading activities are a complement to Generation’s energy marketing portfolio but represent a small portion of Generation’s overall energy marketing activities.

Fair value authoritative guidance and disclosures about offsetting assets and liabilities requires the fair value of derivative instruments to be shown in the Combined Notes to Consolidated Financial Statements on a gross basis, even when the derivative instruments are subject to legally enforceable master netting agreements and qualify for net presentation in the Consolidated Balance Sheet. A master netting agreement is an agreement between two counterparties that may have derivative and non-derivative contracts with each other providing for the net settlement of all referencing contracts via one payment stream, which takes place as the contracts deliver, when collateral is requested or in the event of default. Generation’s use of cash collateral is generally unrestricted, unless Generation is downgraded below investment grade (i.e., to BB+ or Ba1). In the table below, Generation’s energy-related economic hedges and proprietary trading derivatives are shown gross. The impact of the netting of fair value balances with the same counterparty that are subject to legally enforceable master netting agreements, as well as netting of cash collateral, including margin on exchange positions, is aggregated in the collateral and netting column. As of June 30, 2018 and December 31, 2017, $9 million and $4 million of cash collateral held, respectively, was not offset against derivative positions because such collateral was not associated with any energy-related derivatives, were associated with accrual positions, or had no positions to offset as of the balance sheet date. Excluded from the tables below are economic hedges that qualify for the NPNS scope exception and other non-derivative contracts that are accounted for under the accrual method of accounting.

ComEd’s use of cash collateral is generally unrestricted unless ComEd is downgraded below investment grade (i.e., to BB+ or Ba1).

Cash collateral held by PECO and BGE must be deposited in an unaffiliated major U.S. commercial bank or foreign bank with a U.S. branch office that meet certain qualifications.

In the table below, DPL's economic hedges are shown gross. The impact of the netting of fair value balances with the same counterparty that are subject to legally enforceable master netting agreements, as well as netting of cash collateral, including margin on exchange positions, is aggregated in the collateral and netting column.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of June 30, 2018:

	Generation				ComEd	DPL			Exelon
Derivatives	Economic Hedges	Proprietary Trading	Collateral and Netting[(a)(e)]	Subtotal[(b)]	Economic Hedges[(c)]	Economic Hedges[(d)]	Collateral and Netting[(a)]	Subtotal	Total Derivatives
Mark-to-market derivative assets (current assets)	$2,527	$ 163	$ (1,893)	$ 797	$ —	$ —	$ —	$ —	$ 797
Mark-to-market derivative assets (noncurrent assets)	1,571	58	(1,188)	441	—	—	—	—	441
Total mark-to-market derivative assets	4,098	221	(3,081)	1,238	—	—	—	—	1,238
Mark-to-market derivative liabilities (current liabilities)	(2,241)	(132)	2,127	(246)	(23)	—	—	—	(269)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,566)	(40)	1,336	(270)	(229)	—	—	—	(499)
Total mark-to-market derivative liabilities	(3,807)	(172)	3,463	(516)	(252)	—	—	—	(768)
Total mark-to-market derivative net assets (liabilities)	$291	$ 49	$ 382	$ 722	$ (252)	$ —	$ —	$ —	$ 470

(a) Exelon, Generation and DPL net all available amounts allowed under the derivative authoritative guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral. These are not reflected in the table above.

(b) Current and noncurrent assets are shown net of collateral of $115 million and $54 million, respectively, and current and noncurrent liabilities are shown net of collateral of $119 million and $94 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $382 million at June 30, 2018.

(c) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

(d) Represents natural gas futures purchased by DPL as part of a natural gas hedging program approved by the DPSC.

(e) Of the collateral posted/(received), $11 million represents variation margin on the exchanges.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2017:

	Generation				ComEd	DPL			Exelon
Description	Economic Hedges	Proprietary Trading	Collateral and Netting[a][e]	Subtotal[b]	Economic Hedges[c]	Economic Hedges[d]	Collateral and Netting[a]	Subtotal	Total Derivatives
Mark-to-market derivative assets (current assets)	$3,061	$ 56	$(2,144)	$ 973	$ —	$—	$ —	$ —	$ 973
Mark-to-market derivative assets (noncurrent assets)	1,164	12	(845)	331	—	—	—	—	331
Total mark-to-market derivative assets	4,225	68	(2,989)	1,304	—	—	—	—	1,304
Mark-to-market derivative liabilities (current liabilities)	(2,646)	(43)	2,480	(209)	(21)	(1)	1	—	(230)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,137)	(10)	975	(172)	(235)	—	—	—	(407)
Total mark-to-market derivative liabilities	(3,783)	(53)	3,455	(381)	(256)	(1)	1	—	(637)
Total mark-to-market derivative net assets (liabilities)	$442	$ 15	$466	$ 923	$(256)	$(1)	$ 1	$ —	$ 667

(a) Exelon, Generation and DPL net all available amounts allowed under the derivative authoritative guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, and letters of credit and other forms of non-cash collateral. These are not reflected in the table above.

(b) Current and noncurrent assets are shown net of collateral of $169 million and $53 million, respectively, and current and noncurrent liabilities are shown net of collateral of $167 million and $77 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $466 million at December 31, 2017.

(c) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

(d) Represents natural gas futures purchased by DPL as part of a natural gas hedging program approved by the DPSC.

(e) Of the collateral posted/(received), $(117) million represents variation margin on the exchanges.

122

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Economic Hedges (Commodity Price Risk)
Within Exelon, Generation has the most exposure to commodity price risk. As such, Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power and gas sales, fuel and power purchases, natural gas transportation and pipeline capacity agreements and other energy-related products marketed and purchased. To manage these risks, Generation may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from expected sales of power and gas and purchases of power and fuel. The objectives for executing such hedges include fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return. Generation is also exposed to differences between the locational settlement prices of certain economic hedges and the hedged generating units. This price difference is actively managed through other instruments which include derivative congestion products, whose changes in fair value are recognized in earnings each period, and auction revenue rights, which are accounted for on an accrual basis. For the three and six months ended June 30, 2018 and 2017, Exelon and Generation recognized the following net pre-tax commodity mark-to-market gains (losses) which are also located in the "Net fair value changes related to derivatives" on the Consolidated Statements of Cash Flows.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Income Statement Location	Gain (Loss)			
Operating revenues	$(7)	$(141)	$(107)	$(96)
Purchased power and fuel	96	(41)	(70)	(134)
Total Exelon and Generation	$89	$(182)	$(177)	$(230)

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation’s owned and contracted generation positions that have not been hedged. Generation hedges commodity price risk on a ratable basis over three-year periods. As of June 30, 2018, the percentage of expected generation hedged is 97%-100%, 71%-74% and 41%-44% for 2018, 2019 and 2020, respectively.
On December 17, 2010, ComEd executed several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. Delivery under the contracts began in June 2012. These contracts are designed to lock in a portion of the long-term commodity price risk resulting from the renewable energy resource procurement requirements in the Illinois Settlement Legislation. ComEd has not elected hedge accounting for these derivative financial instruments. ComEd records the fair value of the swap contracts on its balance sheet. Because ComEd receives full cost recovery for energy procurement and related costs from retail customers, the change in fair value each period is recorded by ComEd as a regulatory asset or liability. See Note 3 — Regulatory Matters of the Exelon 2017 Form 10-K for additional information.
PECO’s natural gas procurement policy is designed to achieve a reasonable balance of long-term and short-term gas purchases under different pricing approaches to achieve system supply reliability at the least cost. PECO’s reliability strategy is two-fold. First, PECO must assure that there is sufficient transportation capacity to satisfy delivery requirements. Second, PECO must ensure that a firm source of supply exists to utilize the capacity resources. All of PECO’s natural gas supply and asset management agreements that are derivatives either qualify for the NPNS scope exception and have been designated as such or have no mark-to-market balances because the derivatives are index priced. Additionally, in accordance with the 2016 PAPUC PGC settlement and to reduce the exposure of PECO and its customers to natural gas price volatility, PECO has continued its program to purchase natural gas for both winter and summer supplies using a layered approach of locking-in prices ahead of each season with long-

term gas purchase agreements (those with primary terms of at least twelve months). Under the terms of the 2016 PGC settlement, PECO is required to lock in (i.e., economically hedge) the price of a minimum volume of its long-term gas commodity purchases. PECO's gas-hedging program is designed to cover about 20% of planned natural gas purchases in support of projected firm sales. The hedging program for natural gas procurement has no direct impact on PECO's results of operations and financial position as natural gas costs are fully recovered from customers under the PGC.

BGE has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC. The SOS rates charged recover BGE's wholesale power supply costs and include an administrative fee. BGE's commodity price risk related to electric supply procurement is limited. BGE locks in fixed prices for all of its SOS requirements through full requirements contracts. Certain of BGE's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other BGE full requirements contracts are not derivatives.

BGE provides natural gas to its customers under a MBR mechanism approved by the MDPSC. Under this mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers. BGE must also secure fixed price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for flowing (i.e., non-storage) gas for the November through March period. These fixed-price contracts are not subject to sharing under the MBR mechanism. BGE also ensures it has sufficient pipeline transportation capacity to meet customer requirements. BGE's natural gas supply and asset management agreements qualify for the NPNS scope exception and result in physical delivery.

Pepco has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC and DCPSC. The SOS rates charged recover Pepco's wholesale power supply costs and include an administrative fee. The administrative fee includes an incremental cost component and a shareholder return component for residential and commercial rate classes. Pepco's commodity price risk related to electric supply procurement is limited. Pepco locks in fixed prices for its SOS requirements through full requirements contracts. Certain of Pepco's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other Pepco full requirements contracts are not derivatives.

DPL has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC and the DPSC. The SOS rates charged recover DPL's wholesale power supply costs. In Delaware, DPL is also entitled to recover a Reasonable Allowance for Retail Margin (RARM). The RARM includes a fixed annual margin of approximately $2.75 million, plus an incremental cost component and a cash working capital allowance. In Maryland, DPL charges an administrative fee intended to allow it to recover its administrative costs. DPL locks in fixed prices for its SOS requirements through full requirements contracts. DPL's commodity price risk related to electric supply procurement is limited. Certain of DPL's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other DPL full requirements contracts are not derivatives.

DPL provides natural gas to its customers under an Annual GCR mechanism approved by the DPSC. Under this mechanism, DPL's Annual GCR Filing establishes a future GCR for firm bundled sales customers by using a forecast of demand and commodity costs. The actual costs are trued up against forecasts on a monthly basis and any shortfall or excess is carried forward as a recovery balance in the next GCR filing. The demand portion of the GCR is based upon DPL's firm transportation and storage contracts. DPL has firm deliverability of swing and seasonal storage; a liquefied natural gas facility and firm transportation capacity to meet customer demand and provide a reserve margin. The commodity portion of the GCR includes a commission approved hedging program which is intended to reduce gas

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

commodity price volatility while limiting the firm natural gas customers' exposure to adverse changes in the market price of natural gas. The hedge program requires that DPL hedge, on a non-discretionary basis, an amount equal to 50% of estimated purchase requirements for each month, including estimated monthly purchases for storage injections. The 50% hedge monthly target is achieved by hedging 1/12th of the 50% target each month beginning 12-months prior to the month in which the physical gas is to be purchased. Currently, DPL uses only exchange traded futures for its gas hedging program, which are considered derivatives, however, it retains the capability to employ other physical and financial hedges if needed. DPL has not elected hedge accounting for these derivative financial instruments. Because of the DPSC-approved fuel adjustment clause for DPL's derivatives, the change in fair value of the derivatives each period, in addition to all premiums paid and other transaction costs incurred as part of the gas hedging program, are fully recoverable and are recorded by DPL as regulatory assets or liabilities. DPL's physical gas purchases are currently all daily, monthly or intra-month transactions. From time to time, DPL will enter into seasonal purchase or sale arrangements, however, there are none currently in the portfolio. Certain of DPL's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other DPL full requirements contracts are not derivatives.

ACE has contracts to procure BGS electric supply that are executed through a competitive procurement process approved by the NJBPU. The BGS rates charged recover ACE's wholesale power supply costs. ACE does not make any profit or incur any loss on the supply component of the BGS it supplies to customers. ACE's commodity price risk related to electric supply procurement is limited. ACE locks in fixed prices for all of its BGS requirements through full requirements contracts. Certain of ACE's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other ACE full requirements contracts are not derivatives.

Proprietary Trading (Commodity Price Risk)

Generation also executes commodity derivatives for proprietary trading purposes. Proprietary trading includes all contracts executed with the intent of benefiting from shifts or changes in market prices as opposed to those executed with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon's RMC. The proprietary trading portfolio is subject to a risk management policy that includes stringent risk management limits to manage exposure to market risk. Additionally, the Exelon risk management group and Exelon's RMC monitor the financial risks of the proprietary trading activities. The proprietary trading activities are a complement to Generation's energy marketing portfolio but represent a small portion of Generation's overall revenue from energy marketing activities. Gains and losses associated with proprietary trading are reported as Operating revenues in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. For the three and six months ended June 30, 2018 and 2017 Exelon and Generation recognized the following net pre-tax commodity mark-to-market gains (losses) which are also included in the "Net fair value changes related to derivatives" on the Consolidated Statements of Cash Flows. The Utility Registrants do not execute derivatives for proprietary trading purposes.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Income Statement Location	Gain (Loss)			
Operating revenues	$15	$ —	$17	$(1)

Interest Rate and Foreign Exchange Risk (All Registrants)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, to manage their interest rate exposure. In addition, the Registrants may utilize interest

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

rate derivatives to lock in rate levels, which are typically designated as cash flow hedges to manage interest rate risk. To manage foreign exchange rate exposure associated with international commodity purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are treated as economic hedges. Below is a summary of the interest rate and foreign exchange hedge balances as of June 30, 2018:

	Generation				Exelon Corporate	Exelon
Description	Derivatives Designated as Hedging Instruments	Economic Hedges	Collateral and Netting[(a)]	Subtotal	Derivatives Designated as Hedging Instruments	Total
Mark-to-market derivative assets (current assets)	$1	$ 5	$ (4)	$ 2	$ —	$ 2
Mark-to-market derivative assets (noncurrent assets)	15	1	—	16	—	16
Total mark-to-market derivative assets	16	6	(4)	18	—	18
Mark-to-market derivative liabilities (current liabilities)	—	(3)	4	1	—	1
Mark-to-market derivative liabilities (noncurrent liabilities)	—	—	—	—	(8)	(8)
Total mark-to-market derivative liabilities	—	(3)	4	1	(8)	(7)
Total mark-to-market derivative net assets (liabilities)	$16	$ 3	$ —	$ 19	$ (8)	$ 11

(a) Exelon and Generation net all available amounts allowed under the derivative authoritative guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases, Exelon and Generation may have other offsetting counterparty exposures subject to a master netting or similar agreement, such as accrued interest, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral, which are not reflected in the table above.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

The following table provides a summary of the interest rate and foreign exchange hedge balances recorded by the Registrants as of December 31, 2017:

	Generation				Exelon Corporate	Exelon
Description	Derivatives Designated as Hedging Instruments	Economic Hedges	Collateral and Netting(a)	Subtotal	Derivatives Designated as Hedging Instruments	Total
Mark-to-market derivative assets (current assets)	$—	$ 10	$ (7)	$ 3	$ —	$ 3
Mark-to-market derivative assets (noncurrent assets)	3	—	—	3	3	6
Total mark-to-market derivative assets	3	10	(7)	6	3	9
Mark-to-market derivative liabilities (current liabilities)	(2)	(7)	7	(2)	—	(2)
Mark-to-market derivative liabilities (noncurrent liabilities)	—	(2)	—	(2)	—	(2)
Total mark-to-market derivative liabilities	(2)	(9)	7	(4)	—	(4)
Total mark-to-market derivative net assets (liabilities)	$1	$ 1	$ —	$ 2	$ 3	$ 5

(a) Exelon and Generation net all available amounts allowed under the derivative authoritative guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases, Exelon and Generation may have other offsetting counterparty exposures subject to a master netting or similar agreement, such as accrued interest, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral, which are not reflected in the table above.

Fair Value Hedges (Interest Rate Risk)

For derivative instruments that qualify and are designated as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in earnings immediately. Exelon and Generation include the gain or loss on the hedged items and the offsetting loss or gain on the related interest rate swaps as follows:

		Three Months Ended June 30,			
	Income Statement	2018	2017	2018	2017
	Location	Gain (loss) on Swaps		Gain on Borrowings	
Exelon	Interest expense	$(4)	$1	$ 7	$ 2

		Six Months Ended June 30,			
	Income Statement	2018	2017	2018	2017
	Location	Loss on Swaps		Gain on Borrowings	
Exelon	Interest expense	$(11)	$(4)	$ 20	$ 10

The table below provides the notional amounts of fixed-to-floating hedges outstanding held by Exelon at June 30, 2018 and December 31, 2017:

	As of June 30, 2018	December 31, 2017
Fixed-to-floating hedges	$800	$ 800

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

During the three months ended June 30, 2018 and 2017, the impact on the results of operations as a result of ineffectiveness from fair value hedges was a $3 million gain and a $3 million gain, respectively. During the six months ended June 30, 2018 and 2017, the impact on the results of operations as a result of ineffectiveness from fair value hedges was a $9 million gain and a $7 million gain, respectively.

Cash Flow Hedges (Interest Rate Risk)

For derivative instruments that qualify and are designated as cash flow hedges, the gain or loss on the effective portion of the derivative will be deferred in AOCI and reclassified into earnings when the underlying transaction occurs. To mitigate interest rate risk, Exelon and Generation enter into floating-to-fixed interest rate swaps to manage a portion of interest rate exposure associated with debt issuances. The table below provides the notional amounts of floating-to-fixed hedges outstanding held by Exelon and Generation as of June 30, 2018.

	As of June 30, 2018	December 31, 2017
Floating-to-fixed hedges	$624	$ 636

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

The tables below provide the activity of OCI related to cash flow hedges for the three and six months ended June 30, 2018 and 2017, containing information about the changes in the fair value of cash flow hedges and the reclassification from AOCI into results of operations. The amounts reclassified from OCI, when combined with the impacts of the hedged transactions, result in the ultimate recognition of net revenues or expenses at the contractual price.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
Three Months Ended June 30, 2018	Income Statement Location	Generation Total Cash Flow Hedges	Exelon Total Cash Flow Hedges
AOCI derivative loss at March 31, 2018		$ (9)	$ (6)
Effective portion of changes in fair value		4	3
Reclassifications from AOCI to net income	Interest Expense	1	1
AOCI derivative loss at June 30, 2018		$ (4)	$ (2)

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
Six Months Ended June 30, 2018	Income Statement Location	Generation Total Cash Flow Hedges	Exelon Total Cash Flow Hedges
AOCI derivative loss at December 31, 2017		$ (16)	$ (14)
Effective portion of changes in fair value		11	11
Reclassifications from AOCI to net income	Interest Expense	1	1
AOCI derivative loss at June 30, 2018		$ (4)	$ (2)

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
Three Months Ended June 30, 2017	Income Statement Location	Generation Total Cash Flow Hedges	Exelon Total Cash Flow Hedges
AOCI derivative loss at March 31, 2017		$ (13)	$ (11)
Effective portion of changes in fair value		(1)	(1)
AOCI derivative loss at June 30, 2017		$ (14)	$ (12)

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
Six Months Ended June 30, 2017	Income Statement Location	Generation Total Cash Flow Hedges	Exelon Total Cash Flow Hedges

AOCI derivative loss at December 31, 2016		$ (19)	$ (17)
Effective portion of changes in fair value		1	1
Reclassifications from AOCI to net income	Interest Expense	4 (a)	4 (a)
AOCI derivative loss at June 30, 2017		$ (14)	$ (12)

(a) Amount is net of related income tax expense of $3 million for the six months ended June 30, 2017.

During the three and six months ended June 30, 2018 and 2017, the impact on the results of operations as a result of ineffectiveness from cash flow hedges in continuing designated hedge relationships was immaterial. The estimated amount of existing gains and losses that are reported in

129

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

AOCI at the reporting date that are expected to be reclassified into earnings within the next twelve months is immaterial.

Economic Hedges (Interest Rate and Foreign Exchange Risk)

Exelon and Generation executes these instruments to mitigate exposure to fluctuations in interest rates or foreign exchange but for which the fair value or cash flow hedge elections were not made. Generation also enters into interest rate derivative contracts and foreign exchange currency swaps ("treasury") to manage the exposure related to the interest rate component of commodity positions and international purchases of commodities in currencies other than U.S. Dollars.

At June 30, 2018 and December 31, 2017, Generation had immaterial notional amounts of interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The following table provides notional amounts outstanding held by Exelon and Generation at June 30, 2018 and December 31, 2017 related to foreign currency exchange rate swaps that are marked-to-market to manage the exposure associated with international purchases of commodities in currencies other than U.S. dollars.

	As of June 30, 2018	As of December 31, 2017
Foreign currency exchange rate swaps	$86	$ 94

For the three and six months ended June 30, 2018 and 2017, Exelon and Generation recognized the following net pre-tax mark-to-market gains (losses) in the Consolidated Statements of Operations and Comprehensive Income and are included in “Net fair value changes related to derivatives” in Exelon’s and Generation’s Consolidated Statements of Cash Flows.

		Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
	Income Statement Location	Gain (Loss)			
Generation	Operating Revenues	$2	$(2)	$5	$(3)
Generation	Purchased Power and Fuel	(1)	—	(3)	—
Total Generation		$1	$(2)	$2	$(3)

		Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
	Income Statement Location	Gain (Loss)			
Exelon	Operating Revenues	$2	$(2)	$5	$(3)
Exelon	Purchased Power and Fuel	(1)	—	(3)	—
Total Exelon		$1	$(2)	$2	$(3)

130

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Proprietary Trading (Interest Rate and Foreign Exchange Risk)
Generation also executes derivative contracts for proprietary trading purposes to hedge risk associated with the interest rate and foreign exchange components of underlying commodity positions. Gains and losses associated with proprietary trading are reported as Operating revenues in Exelon’s and Generation’s Consolidated Statements of Operations and Comprehensive Income and are included in “Net fair value changes related to derivatives” in Exelon’s and Generation’s Consolidated Statements of Cash Flows. For the three and six months ended June 30, 2018 and for the three months ended June 30, 2017, Exelon and Generation recognized no net pre-tax commodity mark-to-market gains or losses. For the six months ended June 30, 2017, Exelon and Generation recognized a $1 million net pre-tax commodity mark-to-market loss.
Credit Risk, Collateral and Contingent-Related Features (All Registrants)
The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties on executed derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. For commodity derivatives, Generation enters into enabling agreements that allow for payment netting with its counterparties, which reduces Generation’s exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. Typically, each enabling agreement is for a specific commodity and so, with respect to each individual counterparty, netting is limited to transactions involving that specific commodity product, except where master netting agreements exist with a counterparty that allow for cross product netting. In addition to payment netting language in the enabling agreement, Generation’s credit department establishes credit limits, margining thresholds and collateral requirements for each counterparty, which are defined in the derivative contracts. Counterparty credit limits are based on an internal credit review process that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings by credit rating agencies, and risk management capabilities. To the extent that a counterparty’s margining thresholds are exceeded, the counterparty is required to post collateral with Generation as specified in each enabling agreement. Generation’s credit department monitors current and forward credit exposure to counterparties and their affiliates, both on an individual and an aggregate basis.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

The following tables provide information on Generation's credit exposure for all derivative instruments, NPNS and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of June 30, 2018. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties. The figures in the tables below exclude credit risk exposure from individual retail counterparties, nuclear fuel procurement contracts and exposure through RTOs, ISOs, NYMEX, ICE, NASDAQ, NGX and Nodal commodity exchanges. Additionally, the figures in the tables below exclude exposures with affiliates, including net receivables with ComEd, PECO, BGE, Pepco, DPL and ACE of $47 million, $23 million, $23 million, $31 million, $5 million, and $4 million as of June 30, 2018, respectively.

Rating as of June 30, 2018	Total Exposure Before Credit Collateral	Credit Collateral[(a)]	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 823	$ —	$ 823	1	$ 206
Non-investment grade	90	30	60		
No external ratings					
Internally rated — investment grade	228	—	228		
Internally rated — non-investment grade	78	13	65		
Total	$ 1,219	$ 43	$ 1,176	1	$ 206

Net Credit Exposure by Type of Counterparty	As of June 30, 2018
Financial institutions	$ 97
Investor-owned utilities, marketers, power producers	627
Energy cooperatives and municipalities	392
Other	60
Total	$ 1,176

(a) As of June 30, 2018, credit collateral held from counterparties where Generation had credit exposure included $22 million of cash and $21 million of letters of credit. The credit collateral does not include non-liquid collateral.

ComEd's power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on daily, updated forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price on a given day, the suppliers are required to post collateral for the secured credit portion after adjusting for any unpaid deliveries and unsecured credit allowed under the contract. The unsecured credit used by the suppliers represents ComEd's net credit exposure. As of June 30, 2018, ComEd's net credit exposure to suppliers was less than $1 million.

ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation. ComEd's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3 — Regulatory Matters of the Exelon 2017 Form 10-K for additional information.

PECO's unsecured credit used by the suppliers represents PECO's net credit exposure. As of June 30, 2018, PECO had no material net credit exposure to suppliers.

Table of Contents

PECO's natural gas procurement plan is reviewed and approved annually on a prospective basis by the PAPUC. PECO's counterparty credit risk under its natural gas supply and asset management agreements is mitigated by its ability to recover its natural gas costs through the PGC, which allows PECO to adjust rates quarterly to reflect realized natural gas prices. As of June 30, 2018, PECO had no material credit exposure under its natural gas supply and asset management agreements with investment grade suppliers.

BGE is permitted to recover its costs of procuring energy through the MDPSC-approved procurement tariffs. BGE's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3 — Regulatory Matters of the Exelon 2017 Form 10-K for additional information.

BGE's full requirement wholesale electric power agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier, or its guarantor, to meet its credit requirements with a certain amount of unsecured credit. As of June 30, 2018, BGE's net credit exposure to suppliers was immaterial.

BGE's regulated gas business is exposed to market-price risk. At June 30, 2018, BGE had credit exposure of approximately $5 million related to off-system sales which is mitigated by parental guarantees, letters of credit or right to offset clauses within other contracts with those third-party suppliers.

Pepco's, DPL's and ACE's power procurement contracts provide suppliers with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The unsecured credit used by the suppliers represents Pepco's, DPL's and ACE's net credit exposure. As of June 30, 2018, Pepco's, DPL's and ACE's net credit exposures to suppliers were immaterial.

Pepco is permitted to recover its costs of procuring energy through the MDPSC-approved and DCPSC-approved procurement tariffs. DPL is permitted to recover its costs of procuring energy through the MDPSC-approved and DPSC-approved procurement tariffs. ACE is permitted to recover its costs of procuring energy through the NJBPU-approved procurement tariffs. Pepco's, DPL's and ACE's counterparty credit risks are mitigated by their ability to recover realized energy costs through customer rates. See Note 3 — Regulatory Matters of the Exelon 2017 Form 10-K for additional information.

DPL's natural gas procurement plan is reviewed and approved annually on a prospective basis by the DPSC. DPL's counterparty credit risk under its natural gas supply and asset management agreements is mitigated by its ability to recover its natural gas costs through the GCR, which allows DPL to adjust rates annually to reflect realized natural gas prices. To the extent that the fair value of the transactions in a net loss position exceeds the unsecured credit threshold, then collateral is required to be posted in an amount equal to the amount by which the unsecured credit threshold is exceeded. Exchange-traded contracts are required to be fully collateralized without regard to the credit rating of the holder. As of June 30, 2018, DPL's credit exposure under its natural gas supply and asset management agreements with investment grade suppliers was immaterial.

Collateral (All Registrants)

As part of the normal course of business, Generation routinely enters into physically or financially settled contracts for the purchase and sale of electric capacity, electricity, fuels, emissions allowances and other energy-related products. Certain of Generation's derivative instruments contain provisions that require Generation to post collateral. Generation also enters into commodity transactions on

(Dollars in millions, except per share data, unless otherwise noted)

Table of Contents

exchanges where the exchanges act as the counterparty to each trade. Transactions on the exchanges must adhere to comprehensive collateral and margining requirements. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Generation's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit-risk related contingent features stipulate that if Generation were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. This incremental collateral requirement allows for the offsetting of derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master netting agreements. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e., capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below.

The aggregate fair value of all derivative instruments with credit-risk related contingent features in a liability position that are not fully collateralized (excluding transactions on the exchanges that are fully collateralized) is detailed in the table below:

Credit-Risk Related Contingent Features	June 30, 2018	December 31, 2017
Gross fair value of derivative contracts containing this feature[(a)]	$(1,699)	$ (926)
Offsetting fair value of in-the-money contracts under master netting arrangements[(b)]	1,250	577
Net fair value of derivative contracts containing this feature[(c)]	$(449)	$ (349)

(a) Amount represents the gross fair value of out-of-the-money derivative contracts containing credit-risk related contingent features ignoring the effects of master netting agreements.

(b) Amount represents the offsetting fair value of in-the-money derivative contracts under legally enforceable master netting agreements with the same counterparty, which reduces the amount of any liability for which a Registrant could potentially be required to post collateral.

(c) Amount represents the net fair value of out-of-the-money derivative contracts containing credit-risk related contingent features after considering the mitigating effects of offsetting positions under master netting arrangements and reflects the actual net liability upon which any potential contingent collateral obligations would be based.

Generation had cash collateral posted of $420 million and letters of credit posted of $424 million and cash collateral held of $47 million and letters of credit held of $60 million as of June 30, 2018 for external counterparties with derivative positions. Generation had cash collateral posted of $497 million and letters of credit posted of $293 million and cash collateral held of $35 million and letters of credit held of $33 million at December 31, 2017 for external counterparties with derivative positions. In the event of a credit downgrade below investment grade (i.e., to BB+ by S&P or Ba1 by Moody's), Generation would have been required to post additional collateral of $1.5 billion and $1.8 billion as of June 30, 2018 and December 31, 2017, respectively. These amounts represent the potential additional collateral required after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

Generation's and Exelon's interest rate swaps contain provisions that, in the event of a merger, if Generation's debt ratings were to materially weaken, it would be in violation of these provisions, resulting in the ability of the counterparty to terminate the agreement prior to maturity. Collateralization would not be required under any circumstance. Termination of the agreement could result in a settlement payment by Exelon or the counterparty on any interest rate swap in a net liability position. The settlement amount would be equal to the fair value of the swap on the termination date. As of June 30, 2018, Generation's and Exelon's swaps were in an asset position of $19 million and $11 million, respectively.

Table of Contents

See Note 25 — Segment Information of the Exelon 2017 Form 10-K for additional information regarding the letters of credit supporting the cash collateral.

Generation entered into supply forward contracts with certain utilities, including PECO and BGE, with one-sided collateral postings only from Generation. If market prices fall below the benchmark price levels in these contracts, the utilities are not required to post collateral. However, when market prices rise above the benchmark price levels, counterparty suppliers, including Generation, are required to post collateral once certain unsecured credit limits are exceeded. Under the terms of ComEd’s standard block energy contracts, collateral postings are one-sided from suppliers, including Generation, should exposures between market prices and benchmark prices exceed established unsecured credit limits outlined in the contracts. As of June 30, 2018, ComEd held $5 million in collateral from suppliers in association with energy procurement contracts. Under the terms of ComEd's REC and ZEC contracts, collateral postings are required to cover a percentage of the REC and ZEC contract value. As of June 30, 2018, ComEd held $14 million in collateral from suppliers for REC and ZEC contract obligations. Under the terms of ComEd’s long-term renewable energy contracts, collateral postings are required from suppliers for both RECs and energy. The REC portion is a fixed value and the energy portion is one-sided from suppliers should the forward market prices exceed contract prices. As of June 30, 2018, ComEd held $19 million in collateral from suppliers for the long-term renewable energy contracts. If ComEd lost its investment grade credit rating as of June 30, 2018, it would have been required to post approximately $8 million of collateral to its counterparties. See Note 3 — Regulatory Matters of the Exelon 2017 Form 10-K for additional information.

PECO’s natural gas procurement contracts contain provisions that could require PECO to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon PECO’s credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of June 30, 2018, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of June 30, 2018, PECO could have been required to post approximately $20 million of collateral to its counterparties.

PECO’s supplier master agreements that govern the terms of its DSP Program contracts do not contain provisions that would require PECO to post collateral.

BGE’s natural gas procurement contracts contain provisions that could require BGE to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon BGE’s credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of June 30, 2018, BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of June 30, 2018, BGE could have been required to post approximately $36 million of collateral to its counterparties.

DPL's natural gas procurement contracts contain provisions that could require DPL to post collateral. To the extent that the fair value of the natural gas derivative transaction in a net loss position exceeds the unsecured credit threshold, then collateral is required to be posted in an amount equal to the amount by which the unsecured credit threshold is exceeded. The DPL obligations are standalone, without the guaranty of PHI. If DPL lost its investment grade credit rating as of June 30, 2018, DPL could have been required to post an additional amount of approximately $11 million of collateral to its counterparties.

BGE's, Pepco's, DPL's and ACE's full requirements wholesale power agreements that govern the terms of its electric supply procurement contracts do not contain provisions that would require BGE, Pepco, DPL or ACE to post collateral.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

11. Debt and Credit Agreements (All Registrants)
Short-Term Borrowings
Exelon Corporate, ComEd, BGE, Pepco, DPL and ACE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the Exelon intercompany money pool. PHI Corporate meets its short-term liquidity requirements primarily through the issuance of short-term notes and the Exelon intercompany money pool. The Registrants may use their respective credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit.
Commercial Paper
The Registrants had the following amounts of commercial paper borrowings outstanding as of June 30, 2018 and December 31, 2017:

Commercial Paper Borrowings	June 30, 2018	December 31, 2017
Exelon	$628	$ 427
ComEd	320	—
PECO	50	—
BGE	136	77
PHI[(a)]	122	350
Pepco	—	26
DPL	—	216
ACE	122	108

(a) PHI reflects the commercial paper borrowings outstanding of Pepco, DPL and ACE.
Short-Term Loan Agreements
On January 13, 2016, PHI entered into a $500 million term loan agreement, which was amended on March 28, 2016. The net proceeds of the loan were used to repay PHI's outstanding commercial paper and for general corporate purposes. Pursuant to the loan agreement, as amended, loans made thereunder bear interest at a variable rate equal to LIBOR plus 1%, and all indebtedness thereunder is unsecured. On March 23, 2017, the aggregate principal amount of all loans, together with any accrued but unpaid interest due under the loan agreement was fully repaid and the loan terminated. On March 23, 2017, Exelon Corporate entered into a similar type term loan for $500 million which expired March 22, 2018. The loan agreement was renewed on March 22, 2018 and will expire on March 21, 2019. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 1% and all indebtedness thereunder is unsecured.
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% and all indebtedness thereunder is unsecured.
Credit Agreements
As of March 15, 2018, the credit agreement for a Generation bilateral credit facility of $30 million was amended to increase the overall facility size to $95 million. This facility will solely be used by Generation to issue letters of credit.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

On May 26, 2018, each of the Registrants' respective syndicated revolving credit facilities had their maturity dates extended to May 26, 2023.

Long-Term Debt

Issuance of Long-Term Debt

During the six months ended June 30, 2018, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	Energy Efficiency Project Financing	3.72 %	September 30, 2018	$ 4	Funding to install energy conservation measures for the Smithsonian Zoo project.
Generation	Energy Efficiency Project Financing	3.17 %	April 30, 2018	$ 1	Funding to install energy conservation measures in Brooklyn, NY.
Generation	Energy Efficiency Project Financing	2.61 %	September 30, 2018	$ 4	Funding to install energy conservation measures for the Pensacola project.
Generation	Energy Efficiency Project Financing	4.17 %	January 1, 2019	$ 1	Funding to install energy conservation measures for the General Services Administration Philadelphia project.
Generation	Energy Efficiency Project Financing	4.26 %	May 1, 2019	$ 3	Funding to install energy conservation measures for the National Institutes of Health Multi-Buildings Phase II project.
ComEd	First Mortgage Bonds, Series 124	4.00 %	March 1, 2048	$ 800	Refinance one series of maturing first mortgage bonds, to repay a portion of ComEd’s outstanding commercial paper obligations and to fund general corporate purposes.
PECO	First and Refunding Mortgage Bonds	3.90 %	March 1, 2048	$ 325	Refinance a portion of maturing mortgage bonds.
PECO	Loan Agreement	2.00 %	June 20, 2023	$ 50	Funding to implement Electric Long-term Infrastructure Improvement Plan
Pepco	First Mortgage Bonds	4.27 %	June 15, 2048	$ 100	Repay existing indebtedness and for general corporate purposes
DPL	First Mortgage Bonds	4.27 %	June 15, 2048	$ 200	Repay existing indebtedness and for general corporate purposes

12. Income Taxes (All Registrants)

Corporate Tax Reform (All Registrants)

On December 22, 2017, President Trump signed the TCJA into law. The TCJA makes many significant changes to the Internal Revenue Code, including, but not limited to, (1) reducing the U.S. federal corporate tax rate from 35% to 21%; (2) creating a 30% limitation on deductible interest expense (not applicable to regulated utilities); (3) allowing 100% expensing for the cost of qualified property (not applicable to regulated utilities); (4) eliminating the domestic production activities deduction; (5) eliminating the corporate alternative minimum tax and changing how existing alternative minimum tax credits can be realized; and (6) changing rules related to uses and limitations of net operating loss carryforwards created in tax years beginning after December 31, 2017. The most significant change that impacts the Registrants is the reduction of the corporate federal income tax rate from 35% to 21% beginning January 1, 2018. Pursuant to the enactment of the TCJA, the Registrants remeasured their existing deferred income tax balances as of December 31, 2017 to reflect the decrease in the corporate income tax rate from 35% to 21%, which resulted in a material decrease to their net deferred income tax liability balances as shown in the table below. Generation recorded a corresponding net decrease to income tax expense, while the Utility Registrants recorded corresponding regulatory liabilities or assets to the extent such

Table of Contents

amounts are probable of settlement or recovery through customer rates and an adjustment to income tax expense for all other amounts. The amount and timing of potential settlements of the established net regulatory liabilities will be determined by the Utility Registrants' respective rate regulators, subject to certain IRS "normalization" rules. See Note 6 — Regulatory Matters for additional information.

The Registrants have completed their assessment of the majority of the applicable provisions in the TCJA and have recorded the associated impacts as of December 31, 2017. As discussed further below, under SAB 118 issued by the SEC in December 2017, the Registrants have recorded provisional income tax amounts as of December 31, 2017 for changes pursuant to the TCJA related to depreciation for which the impacts could not be finalized upon issuance of the Registrants' financial statements, but for which reasonable estimates could be determined.

For property acquired and placed-in-service after September 27, 2017, the TCJA repeals 50% bonus depreciation for all taxpayers and in addition provides for 100% expensing for taxpayers other than regulated utilities. As a result, Generation will be required to evaluate the contractual terms of its fourth quarter 2017 capital additions and determine if they qualify for 100% expensing under the TCJA as compared to 50% bonus depreciation under prior tax law. Similarly, the Utility Registrants will be required to evaluate the contractual terms of their fourth quarter 2017 capital additions to determine whether they still qualify for the prior tax law's 50% bonus depreciation as compared to no bonus depreciation pursuant to the TCJA.

At Generation, any required changes to the provisional estimates during the measurement period related to the above item would result in an adjustment to current income tax expense at 35% and a corresponding adjustment to deferred income tax expense at 21% and such changes could be material to Generation's future results of operations. At the Utility Registrants, any required changes to the provisional estimates would result in the recording of regulatory assets or liabilities to the extent such amounts are probable of settlement or recovery through customer rates and a net change to income tax expense for any other amounts.

The Registrants expect any final adjustments to the provisional amounts to be recorded by the fourth quarter of 2018, which could be material to the Registrants' future results of operations or financial positions. The accounting for all other applicable provisions of the TCJA is considered complete based on our current interpretation of the provisions of the TCJA as enacted as of December 31, 2017.

While the Registrants have recorded the impacts of the TCJA based on their interpretation of the provisions as enacted, it is expected that technical corrections or other forms of guidance will be issued during 2018, which could result in material changes to previously finalized provisions. At this time, most states have not provided guidance regarding TCJA impacts and may issue guidance in 2018 which may impact estimates.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

The one-time impacts recorded by the Registrants to remeasure their deferred income tax balances at the 21% corporate federal income tax rate as of December 31, 2017 are presented below:

	Exelon[b]	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Net Decrease to Deferred Income Tax Liability Balances	$ 8,624	$ 1,895	$2,819	$1,407	$1,120	$1,944	$968	$540	$456

	Exelon	Generation	ComEd	PECO[c]	BGE	PHI	Pepco	DPL	ACE
Net Regulatory Liability Recorded[a]	$7,315	N/A	$2,818	$ 1,394	$1,124	$1,979	$976	$545	$458

	Exelon[b]	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Net Deferred Income Tax Benefit/(Expense) Recorded	$ 1,309	$ 1,895	$ 1	$ 13	$(4)	$(35)	$ (8)	$(5)	$(2)

(a) Reflects the net regulatory liabilities recorded on a pre-tax basis before taking into consideration the income tax benefits associated with the ultimate settlement with customers.
(b) Amounts do not sum across due to deferred tax adjustments recorded at the Exelon Corporation parent company, primarily related to certain employee compensation plans.
(c) Given the regulatory treatment of income tax benefits related to electric and gas distribution repairs, PECO was in an overall net regulatory asset position as of December 31, 2017 after recording the impacts related to the TCJA. See Note 6 - Regulatory Matters for additional information.

The net regulatory liabilities above include (1) amounts subject to IRS “normalization” rules that are required to be passed back to customers generally over the remaining useful life of the underlying assets giving rise to the associated deferred income taxes, and (2) amounts for which the timing of settlement with customers is subject to determinations by the rate regulators. The table below sets forth the Registrants’ estimated categorization of their net regulatory liabilities as of December 31, 2017. The amounts in the table below are shown on an after-tax basis reflecting future net cash outflows after taking into consideration the income tax benefits associated with the ultimate settlement with customers.

	Exelon	ComEd	PECO[a]	BGE	PHI	PEPCO	DPL	ACE
Subject to IRS Normalization Rules	$3,040	$1,400	$ 533	$459	$648	$ 299	$195	$153
Subject to Rate Regulator Determination	1,694	573	43	324	754	391	194	170
Net Regulatory Liabilities	$4,734	$1,973	$ 576	$783	$1,402	$ 690	$389	$323

(a) Given the regulatory treatment of income tax benefits related to electric and gas distribution repairs, PECO remains in an overall net regulatory asset position as of December 31, 2017 after recording the impacts related to the TCJA. As a result, the amount of customer benefits resulting from the TCJA subject to the discretion of PECO's rate regulators are lower relative to the other Utility Registrants. See Note 6 - Regulatory Matters for additional information.

The net regulatory liability amounts subject to the IRS normalization rules generally relate to property, plant and equipment with remaining useful lives ranging from 30 to 40 years across the Utility Registrants. For the other amounts, the pass back period is subject to determinations by the rate regulators. See Note 6 - Regulatory Matters for the status of and information regarding the Registrants' TCJA-related regulatory filings.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Rate Reconciliation

The effective income tax rate from continuing operations varies from the U.S. Federal statutory rate principally due to the following:

	Three Months Ended June 30, 2018								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
U.S. Federal statutory rate	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%
Increase (decrease) due to:									
State income taxes, net of Federal income tax benefit	3.4	4.3	8.1	(3.4)	6.5	6.2	4.7	6.5	7.6
Qualified nuclear decommissioning trust fund income	0.2	0.5	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(0.9)	(2.4)	(0.2)	(0.1)	(0.2)	(0.2)	(0.1)	(0.3)	(0.3)
Plant basis differences	(3.0)	—	(0.1)	(17.2)	(0.7)	(1.2)	(2.0)	—	(0.2)
Production tax credits and other credits	(1.7)	(4.9)	(0.1)	—	—	—	—	—	—
Noncontrolling interests	(1.5)	(4.5)	—	—	—	—	—	—	—
Excess deferred tax amortization	(5.2)	—	(7.6)	(0.3)	(7.2)	(11.3)	(11.7)	(11.2)	(8.8)
Tax Cuts and Jobs Act of 2017	(1.3)	(1.7)	(0.7)	—	0.1	0.8	—	—	—
Other	(0.2)	(1.3)	0.4	(1.1)	0.8	(0.1)	(0.4)	0.1	0.7
Effective income tax rate	10.8%	11.0%	20.8%	(1.1)%	20.3%	15.2%	11.5%	16.1%	20.0%

140

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	Three Months Ended June 30, 2017[a]								
	Exelon[b]	Generation[c]	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:									
State income taxes, net of Federal income tax benefit	(53.6)	6.0	5.8	(0.6)	5.0	4.3	3.2	4.6	5.6
Qualified nuclear decommissioning trust fund income	64.3	(6.9)	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(10.8)	0.9	(0.2)	(0.1)	(0.2)	(0.1)	(0.1)	(0.1)	(0.4)
Plant basis differences	(56.3)	—	(0.2)	(16.0)	(0.3)	(4.8)	(6.2)	(1.7)	(3.3)
Production tax credits and other credits	(21.1)	2.3	—	—	—	—	—	—	—
Noncontrolling interests	(11.1)	1.2	—	—	—	—	—	—	—
Like-Kind Exchange[d]	(109.3)	—	5.9	—	—	—	—	—	—
Other	11.7	1.0	0.5	0.2	1.3	0.9	(0.2)	0.9	(3.6)
Effective income tax rate	(151.2)%	39.5%	46.8%	18.5%	40.8%	35.3%	31.7%	38.7%	33.3%

	Six Months Ended June 30, 2018								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
U.S. Federal statutory rate	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%
Increase (decrease) due to:									
State income taxes, net of Federal income tax benefit	3.8	3.4	8.1	(3.6)	6.4	5.5	3.7	6.4	7.2
Qualified nuclear decommissioning trust fund income	(0.1)	(0.4)	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(1.1)	(3.3)	(0.2)	(0.1)	(0.1)	(0.2)	(0.1)	(0.3)	(0.3)
Plant basis differences	(2.8)	—	—	(15.6)	(0.7)	(1.8)	(2.5)	(0.7)	(1.3)
Production tax credits and other credits	(2.3)	(7.2)	(0.1)	—	—	—	—	—	—
Noncontrolling interests	(1.1)	(3.5)	—	—	—	—	—	—	—
Excess deferred tax amortization	(5.6)	—	(7.5)	(2.7)	(8.2)	(11.0)	(12.1)	(9.4)	(8.8)
Tax Cuts and Jobs Act of 2017	(0.6)	(0.9)	(0.3)	—	—	0.5	—	—	—
Other	(1.7)	(1.3)	0.1	(0.4)	0.2	(0.1)	(0.4)	0.4	(1.1)
Effective income tax rate	9.5%	7.8%	21.1%	(1.4)%	18.6%	13.9%	9.6%	17.4%	16.7%

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	Six Months Ended June 30, 2017[(a)]								
	Exelon[(b)]	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:									
State income taxes, net of Federal income tax benefit	(0.9)	(10.9)	5.3	(0.1)	5.1	4.6	3.8	5.1	5.6
Qualified nuclear decommissioning trust fund income	5.5	42.8	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(0.7)	(4.5)	(0.2)	(0.1)	(0.1)	(0.2)	(0.1)	(0.2)	(0.4)
Plant basis differences	(4.2)	—	(0.2)	(14.3)	(0.7)	(4.3)	(6.0)	(1.8)	(3.3)
Production tax credits and other credits	(1.3)	(10.3)	—	—	—	—	—	—	—
Noncontrolling interests	(0.3)	(2.6)	—	—	—	—	—	—	—
Merger expenses[(e)]	(11.2)	(11.4)	—	—	—	(23.8)	(16.2)	(15.1)	(85.3)
FitzPatrick bargain purchase gain	(6.4)	(50.1)	—	—	—	—	—	—	—
Like-Kind Exchange[(d)]	(3.6)	—	2.9	—	—	—	—	—	—
Other	0.2	(3.8)	0.4	(0.1)	0.3	—	(0.7)	1.0	(1.6)
Effective income tax rate	12.1%	(15.8)%	43.2%	20.4%	39.6%	11.3%	15.8%	24.0%	(50.0)%

(a) Exelon retrospectively adopted the new standard Revenue from Contracts with Customers. The standard was adopted as of January 1, 2018. The effective income tax rates are recast to reflect the impact of the new standard.
(b) The effective tax rate for the three months ended June 30, 2017 is disproportionately impacted due to the decline in consolidated pre-tax GAAP earnings as compared to the federal and state tax impacts of the Like-kind exchange, tax credits, Plant basis differences, and Qualified nuclear decommissioning trust fund income.
(c) Generation recognized a loss before income taxes for the three months ended June 30, 2017. As a result, positive percentages represent an income tax benefit for the period presented.
(d) Exelon and ComEd recorded the impact of the IRS's finalization of the LKE computation in the second quarter of 2017.
(e) Includes a remeasurement of uncertain federal and state income tax positions.

Accounting for Uncertainty in Income Taxes

The Registrants have the following unrecognized tax benefits as of June 30, 2018 and December 31, 2017:

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
June 30, 2018	$ 732	$ 454	$ 2	$ —	$ 120	$ 135	$ 68	$ 21	$ 14

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
December 31, 2017	$ 743	$ 468	$ 2	$ —	$ 120	$ 125	$ 59	$ 21	$ 14

Table of Contents

Reasonably possible the total amount of unrecognized tax benefits could significantly increase or decrease within 12 months after the reporting date

Like-Kind Exchange

As of June 30, 2018, Exelon and ComEd have approximately $33 million and $2 million, respectively, of unrecognized federal and state income tax benefits that could significantly decrease within the 12 months after the reporting date due to a final resolution of the like-kind exchange litigation described below. The recognition of these unrecognized tax benefits would decrease Exelon and ComEd's effective tax rate.

Settlement of Income Tax Audits, Refund Claims, and Litigation

As of June 30, 2018, Exelon, Generation, BGE, PHI, Pepco, DPL and ACE have approximately $681 million, $458 million, $120 million, $103 million, $68 million, $21 million and $14 million of unrecognized federal and state tax benefits that could significantly decrease within the 12 months after the reporting date as a result of completing audits, potential settlements, and the outcomes of pending court cases. Of the above unrecognized tax benefits, Exelon and Generation have $444 million that, if recognized, would decrease the effective tax rate. The unrecognized tax benefits related to BGE, Pepco, DPL, and ACE, if recognized, may be included in future regulated base rates and that portion would have no impact to the effective tax rate.

As a result of a court decision issued in July 2018 to an unrelated taxpayer, Exelon's and Generation’s unrecognized federal and state tax benefits may increase in the third quarter 2018 by as much as $75 million. As much as $25 million of this increase could impact Exelon's and Generation’s effective tax rate and result in a charge to earnings in the third quarter 2018.

Other Income Tax Matters

Like-Kind Exchange (Exelon and ComEd)

Exelon, through its ComEd subsidiary, took a position on its 1999 income tax return to defer approximately $1.2 billion of tax gain on the sale of ComEd’s fossil generating assets. The gain was deferred by reinvesting a portion of the proceeds from the sale in qualifying replacement property under the like-kind exchange provisions of the IRC. The like-kind exchange replacement property purchased by Exelon included interests in three municipal-owned electric generation facilities which were properly leased back to the municipalities. As previously disclosed, Exelon terminated its investment in one of the leases in 2014 and the remaining two leases were terminated in 2016.

The IRS asserted that the Exelon purchase and leaseback transaction was substantially similar to a leasing transaction, known as a SILO, which is a listed transaction that the IRS has identified as a potentially abusive tax shelter. Thus, they disagreed with Exelon's position and asserted that the entire gain of approximately $1.2 billion was taxable in 1999. In 2013, the IRS issued a notice of deficiency to Exelon and Exelon filed a petition to initiate litigation in the United States Tax Court. In 2016, the Tax Court held that Exelon was not entitled to defer gain on the transaction. In addition to the tax and interest related to the gain deferral, the Tax Court also ruled that Exelon was liable for $90 million in penalties and interest on the penalties. Exelon has fully paid the amounts assessed resulting from the Tax Court decision.

In September 2017, Exelon appealed the Tax Court decision to the U.S. Court of Appeals for the Seventh Circuit. Oral argument was held in May 2018 and a decision is expected later this year.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

State Income Tax Law Changes

On April 24, 2018, Maryland enacted companion bills, House Bill 1794 and Senate Bill 1090, providing for a phase in of a single sales factor apportionment formula from the current three factor formula for determining an entity's Maryland state income taxes. The single sales factor will be fully phased in by 2022.

In the second quarter of 2018, Exelon, Generation, PHI, Pepco and DPL recorded a one-time increase to deferred income taxes of approximately \$16 million, \$5 million, \$17 million, \$16 million and \$1 million, respectively. At PHI, Pepco and DPL, the increase to the Maryland deferred income tax liability was offset by regulatory assets. Further, the change in tax law is not expected to have a material ongoing impact to Exelon's, Generation's, PHI's, Pepco's or DPL's future results of operations.

13. Nuclear Decommissioning (Exelon and Generation)

Nuclear Decommissioning Asset Retirement Obligations

Generation has a legal obligation to decommission its nuclear power plants following the expiration of their operating licenses. To estimate its decommissioning obligation related to its nuclear generating stations for financial accounting and reporting purposes, Generation uses a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic cash flow models and discount rates. Generation updates its ARO annually, unless circumstances warrant more frequent updates, based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various scenarios.

The following table provides a rollforward of the nuclear decommissioning ARO reflected on Exelon’s and Generation’s Consolidated Balance Sheets from December 31, 2017 to June 30, 2018:

Nuclear decommissioning ARO at December 31, 2017[(a)]	\$9,662
Accretion expense	237
Net increase due to changes in, and timing of, estimated future cash flows	32
Costs incurred related to decommissioning plants	(10)
Nuclear decommissioning ARO at June 30, 2018[(a)]	\$9,921

(a) Includes \$99 million and \$13 million for the current portion of the ARO at June 30, 2018 and December 31, 2017, respectively, which is included in Other current liabilities on Exelon’s and Generation’s Consolidated Balance Sheets.

During the six months ended June 30, 2018, Generation’s total nuclear ARO increased by approximately \$259 million, primarily reflecting the accretion of the ARO liability due to the passage of time and the impact of the February 2, 2018 announcement to retire Oyster Creek at the end of its current operating cycle by October 2018. Refer to Note 8 — Early Plant Retirements for additional information regarding the announced early retirement of Oyster Creek.

Nuclear Decommissioning Trust Fund Investments

NDT funds have been established for each generation station unit to satisfy Generation’s nuclear decommissioning obligations. Generally, NDT funds established for a particular unit may not be used to fund the decommissioning obligations of any other unit.

The NDT funds associated with Generation’s nuclear units have been funded with amounts collected from the previous owners and their respective utility customers. PECO is authorized to collect funds, in revenues, for decommissioning the former PECO nuclear plants through regulated rates, and these

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

collections are scheduled through the operating lives of the former PECO plants. The amounts collected from PECO customers are remitted to Generation and deposited into the NDT funds for the unit for which funds are collected. Every five years, PECO files a rate adjustment with the PAPUC that reflects PECO’s calculations of the estimated amount needed to decommission each of the former PECO units based on updated fund balances and estimated decommissioning costs. The rate adjustment is used to determine the amount collectible from PECO customers. The most recent rate adjustment occurred on January 1, 2018, and the effective rates currently yield annual collections of approximately $4 million. The next five-year adjustment is expected to be reflected in rates charged to PECO customers effective January 1, 2023. See Note 15 — Asset Retirement Obligations of Exelon's 2017 Form 10-K, for information regarding the amount collected from PECO ratepayers for decommissioning costs.
Exelon and Generation had NDT fund investments totaling $13,263 million and $13,349 million at June 30, 2018 and December 31, 2017, respectively.
The following table provides net unrealized gains (losses) on NDT funds for the three and six months ended June 30, 2018 and 2017:

	Exelon and Generation Three Months Ended June 30,		Exelon and Generation Six Months Ended June 30,	
	2018	2017	2018	2017
Net unrealized (losses) gains on decommissioning trust funds — Regulatory Agreement Units[a]	$(194)	$(13)	$(268)	$210
Net unrealized (losses) gains on decommissioning trust funds — Non-Regulatory Agreement Units[b][c]	(120)	70	(215)	235

(a) Net unrealized gains (losses) related to Generation’s NDT funds associated with Regulatory Agreement Units are included in Regulatory liabilities on Exelon’s Consolidated Balance Sheets and Noncurrent payables to affiliates on Generation’s Consolidated Balance Sheets.

(b) Excludes $4 million and $(2) million of net unrealized gains (losses) related to the Zion Station pledged assets for the three months ended June 30, 2018 and 2017, respectively. Excludes $2 million and $(2) million of net unrealized gains (losses) related to the Zion Station pledged assets for the six months ended June 30, 2018 and 2017, respectively. Net unrealized gains (losses) related to Zion Station pledged assets are included in Other current liabilities on Exelon’s and Generation’s Consolidated Balance Sheets.

(c) Net unrealized gains (losses) related to Generation’s NDT funds with Non-Regulatory Agreement Units are included in Other, net on Exelon’s and Generation’s Consolidated Statements of Operations and Comprehensive Income.

Interest and dividends on NDT fund investments are recognized when earned and are included in Other, net on Exelon’s and Generation’s Consolidated Statements of Operations and Comprehensive Income. Interest and dividends earned on the NDT fund investments for the Regulatory Agreement Units are eliminated in Other, net on Exelon’s and Generation’s Consolidated Statement of Operations and Comprehensive Income.
See Note 3 — Regulatory Matters and Note 26 — Related Party Transactions of the Exelon 2017 Form 10-K for information regarding regulatory liabilities at ComEd and PECO and intercompany balances between Generation, ComEd and PECO reflecting the obligation to refund to customers any decommissioning-related assets in excess of the related decommissioning obligations.
Zion Station Decommissioning

On September 1, 2010, Generation completed an Asset Sale Agreement (ASA) with EnergySolutions Inc. and its wholly owned subsidiaries, EnergySolutions, LLC (EnergySolutions) and ZionSolutions, under which ZionSolutions has assumed responsibility for decommissioning Zion Station, which is located in Zion, Illinois and ceased operation in 1998. See Note 15 — Asset Retirement Obligations of the Exelon 2017 Form 10-K for information regarding the specific treatment of assets, including NDT funds, and decommissioning liabilities transferred in the transaction.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

ZionSolutions is subject to certain restrictions on its ability to request reimbursements from the Zion Station NDT funds as defined within the ASA. Therefore, the transfer of the Zion Station assets did not qualify for asset sale accounting treatment and, as a result, the related NDT funds were reclassified to Pledged assets for Zion Station decommissioning within Generation's and Exelon's Consolidated Balance Sheets and will continue to be measured in the same manner as prior to the completion of the transaction. Additionally, the transferred ARO for decommissioning was replaced with a Payable for Zion Station decommissioning in Generation's and Exelon's Consolidated Balance Sheets. Changes in the value of the Zion Station NDT assets, net of applicable taxes, are recorded as a change in the payable to ZionSolutions. At no point will the payable to ZionSolutions exceed the project budget of the costs remaining to decommission Zion Station. Generation has retained its obligation for the SNF. Following ZionSolutions' completion of its contractual obligations and transfer of the NRC license to Generation, Generation will store the SNF at Zion Station until it is transferred to the DOE for ultimate disposal and will complete all remaining decommissioning activities associated with the SNF dry storage facility. Generation has a liability of approximately $117 million which is included within the nuclear decommissioning ARO at June 30, 2018. Generation also has retained NDT assets to fund its obligation to maintain the SNF at Zion Station until transfer to the DOE and to complete all remaining decommissioning activities for the SNF storage facility. Any shortage of funds necessary to maintain the SNF and decommission the SNF storage facility is ultimately required to be funded by Generation. Any Zion Station NDT funds remaining after the completion of all decommissioning activities will be returned to ComEd customers in accordance with the applicable orders. The following table provides the pledged assets and payables to ZionSolutions, and withdrawals by ZionSolutions at June 30, 2018 and December 31, 2017:

	Exelon and Generation	
	June 30, 2018	December 31, 2017
Carrying value of Zion Station pledged assets[a]	$ 21	$ 39
Payable to Zion Solutions[b][c]	20	37
Cumulative withdrawals by Zion Solutions to pay decommissioning costs[d]	962	942

(a) Included in Other current assets within Exelon's and Generation's Consolidated Balance sheets.
(b) Excludes a liability recorded within Exelon's and Generation's Consolidated Balance Sheets related to the tax obligation on the unrealized activity associated with the Zion Station NDT funds. The NDT funds will be utilized to satisfy the tax obligations as gains and losses are realized.
(c) Included in Other current liabilities within Exelon's and Generation's Consolidated Balance Sheets.
(d) Includes project expenses to decommission Zion Station and estimated tax payments on Zion Station NDT fund earnings.

NRC Minimum Funding Requirements

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts to decommission the facility at the end of its life.

Generation filed its biennial decommissioning funding status report with the NRC on March 30, 2017 for all units except for Zion Station which is included in a separate report to the NRC submitted by ZionSolutions (see Zion Station Decommissioning above). The status report demonstrated adequate decommissioning funding assurance for all units except for Peach Bottom unit 1. As a former PECO plant, financial assurance for decommissioning Peach Bottom unit 1 is provided by the NDT fund in addition to collections from PECO ratepayers. As discussed under Nuclear Decommissioning Trust Fund Investments above, the amount collected from PECO ratepayers has been adjusted effective January 1, 2018.

On March 28, 2018, Generation submitted its annual decommissioning funding status report with the NRC for shutdown reactors, reactors within five years of shut down except for Zion Station which is included in a separate report to the NRC submitted by EnergySolutions (see Zion Station Decommissioning above), and reactor involved in an acquisition. This report reflected the status of decommissioning funding assurance as of December 31, 2017 and included an update for the acquisition of FitzPatrick on March 31, 2017, the early retirement of TMI announced on May 30, 2017, an adjustment for the February 2, 2018 announced retirement date of Oyster Creek, and the updated status of Peach Bottom unit 1 based on the new collections rate described above. As of December 31, 2017, Generation provided adequate decommissioning funding assurance for all of its shutdown reactors, reactors within five years of shutdown, and reactor involved in an acquisition.

Generation will file its next decommissioning funding status report with the NRC by March 31, 2019. This report will reflect the status of decommissioning funding assurance as of December 31, 2018. A shortfall at any unit could necessitate that Generation address the shortfall by, among other things, obtaining a parental guarantee for Generation's share of the funding assurance. However, the amount of any guarantee or other assurance will ultimately depend on the decommissioning approach, the associated level of costs, and the decommissioning trust fund investment performance going forward.

14. Retirement Benefits (All Registrants)

Exelon sponsors defined benefit pension plans and other postretirement benefit plans for essentially all current employees. Substantially all non-union employees and electing union employees hired on or after January 1, 2001 participate in cash balance pension plans. Effective January 1, 2009, substantially all newly-hired union-represented employees participate in cash balance pension plans. Effective February 1, 2018, most newly-hired Generation and BSC non-represented employees are not eligible for pension benefits and will instead be eligible to receive an enhanced non-discretionary employer contribution in an Exelon defined contribution savings plan. Effective January 1, 2018, most newly-hired non-represented employees are not eligible for OPEB benefits and employees represented by Local 614 are not eligible for retiree health care benefits.

During the first quarter of 2017, in connection with the acquisition of FitzPatrick, Exelon established a new qualified pension plan and a new OPEB plan and recorded a provisional obligation for Fitzpatrick employees based on information available at the merger date of $38 million and $11 million, respectively. As permitted by business combinations authoritative guidance, during the third quarter of 2017, Exelon updated those obligations based on a final valuation for FitzPatrick employees as of the merger date of March 31, 2017. The updated obligations for pension and OPEB were $16 million and $17 million, respectively. See Note 4 — Mergers, Acquisitions and Dispositions for additional information of the acquisition of FitzPatrick.

Defined Benefit Pension and Other Postretirement Benefits

During the first quarter of 2018, Exelon received an updated valuation of its pension and OPEB to reflect actual census data as of January 1, 2018. This valuation resulted in an increase to the pension and OPEB obligations of $23 million and $14 million, respectively. Additionally, accumulated other comprehensive loss decreased by $18 million (after tax) and regulatory assets and liabilities increased by $61 million and $1 million, respectively.

The majority of the 2018 pension benefit cost for Exelon-sponsored plans is calculated using an expected long-term rate of return on plan assets of 7.00% and a discount rate of 3.62%. The majority of the 2018 other postretirement benefit cost is calculated using an expected long-term rate of return on plan assets of 6.60% for funded plans and a discount rate of 3.61%.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

A portion of the net periodic benefit cost for all plans is capitalized within the Consolidated Balance Sheets. The following table presents the components of Exelon's net periodic benefit costs, prior to capitalization, for the three and six months ended June 30, 2018 and 2017.

	Pension Benefits Three Months Ended June 30,		Other Postretirement Benefits Three Months Ended June 30,	
	2018	2017[(a)]	2018	2017[(a)]
Components of net periodic benefit cost:				
Service cost	$102	$97	$28	$28
Interest cost	200	211	44	46
Expected return on assets	(313)	(299)	(43)	(41)
Amortization of:				
Prior service cost (benefit)	—	1	(47)	(47)
Actuarial loss	157	150	16	15
Settlement charges	1	2	—	—
Net periodic benefit cost	$147	$162	$(2)	$1

	Pension Benefits Six Months Ended June 30,		Other Postretirement Benefits Six Months Ended June 30,	
	2018	2017[(a)]	2018	2017[(a)]
Components of net periodic benefit cost:				
Service cost	$202	$191	$56	$54
Interest cost	401	422	88	91
Expected return on assets	(626)	(598)	(87)	(82)
Amortization of:				
Prior service cost (benefit)	1	1	(93)	(94)
Actuarial loss	314	302	33	31
Settlement charges	1	2	—	—
Net periodic benefit cost	$293	$320	$(3)	$—

(a) FitzPatrick net benefit costs are included for the period after the acquisition date of March 31, 2017.

The amounts below represent Exelon's, Generation's, ComEd's, PECO's, BGE's, BSC's, PHI's, Pepco's, DPL's, ACE's, and PHISCO's allocated portion of the pension and postretirement benefit plan costs. As a result of new pension guidance effective on January 1, 2018, certain balances have been reclassified on Exelon’s Consolidated Statements of Operations and Comprehensive Income for the three and six months ended June 30, 2017. The amounts below represent the Registrants’ as well as BSC's and PHISCO's pension and postretirement benefit plan net periodic benefit costs. For Exelon, the service cost component is included in Operating and maintenance expense and Property, plant and equipment for the three and six months ended June 30, 2018 and 2017, while the non-service cost components are included in Other, net and Regulatory assets for the three and six months ended June 30, 2018 and in Other, net and Property, plant and equipment for the three and six months ended June 30, 2017. For the Registrants other than Exelon, the service cost and non-service cost components are included in Operating and maintenance expense and

Property, plant and equipment on their consolidated financial statements for the three and six months ended June 30, 2018 and 2017.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	Three Months Ended June 30,		Six Months Ended June 30,	
Pension and Other Postretirement Benefit Costs	2018	2017	2018	2017
Exelon[(a)(b)]	$145	$163	$290	$320
Generation[(b)]	51	59	100	113
ComEd	44	44	88	87
PECO	5	7	10	14
BGE	15	16	30	32
BSC[(c)]	13	13	28	26
PHI[(a)]	17	24	34	48
Pepco	3	6	8	13
DPL	2	3	3	6
ACE	3	3	6	7
PHISCO[(d)]	9	12	17	22

____

(a) Exelon reflects the consolidated pension and other postretirement benefit costs of Generation, ComEd, PECO, BGE, BSC, and PHI. PHI reflects the consolidated pension and other postretirement benefit costs of Pepco, DPL, ACE, and PHISCO.
(b) FitzPatrick net benefit costs are included for the period after the acquisition date of March 31, 2017.
(c) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO, BGE, PHI, Pepco, DPL, ACE or PHISCO amounts above.
(d) These amounts represent amounts billed to Pepco, DPL and ACE through intercompany allocations. These amounts are not included in Pepco, DPL or ACE amounts above.

Defined Contribution Savings Plans

The Registrants participate in various 401(k) defined contribution savings plans that are sponsored by Exelon. The plans are qualified under applicable sections of the IRC and allow employees to contribute a portion of their pre-tax and/or after-tax income in accordance with specified guidelines. All Registrants match a percentage of the employee contributions up to certain limits. The following table presents the matching contributions to the savings plans during the three and six months ended June 30, 2018 and 2017, respectively.

	Three Months Ended June 30,		Six Months Ended June 30,	
Savings Plan Matching Contributions	2018	2017	2018	2017
Exelon[(a)(b)]	$50	$ 33	$82	$ 63
Generation[(b)]	28	14	43	28
ComEd	8	8	15	15
PECO	2	2	4	4
BGE	2	3	4	4
BSC[(c)]	7	3	10	5
PHI[(a)]	3	3	6	7
Pepco	1	1	2	2
DPL	1	1	1	1

ACE	—	—	1	1
PHISCO[d]	1	1	2	3

149

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

(a) Exelon reflects the consolidated savings plan matching contributions of Generation, ComEd, PECO, BGE, BSC, and PHI. PHI reflects the consolidated savings plan matching contributions of Pepco, DPL, ACE, and PHISCO.
(b) FitzPatrick net benefit costs are included for the period after the acquisition date of March 31, 2017.
(c) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO, BGE, PHI, Pepco, DPL, ACE or PHISCO amounts above.
(d) These amounts represent amounts billed to Pepco and DPL through intercompany allocations. These amounts are not included in Pepco or DPL amounts above.

15. Changes in Accumulated Other Comprehensive Income (Exelon, Generation and PECO)

The following tables present changes in accumulated other comprehensive income (loss) (AOCI) by component for the six months ended June 30, 2018 and 2017:

Six Months Ended June 30, 2018	Gains (Losses) on Cash Flow Hedges	Unrealized gains (losses) on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan Items	Foreign Currency Items	AOCI of Investments in Unconsolidated Affiliates	Total
Exelon[a]						
Beginning balance	$ (14)	$ 10	$ (2,998) [d]	$ (23)	$ (1)	$ (3,026)
OCI before reclassifications	13	—	20	(6)	1	28
Amounts reclassified from AOCI[b]	(1)	—	88	—	—	87
Net current-period OCI	12	—	108	(6)	1	115
Impact of adoption of Recognition and Measurement of Financial Assets and Liabilities standard	—	(10) [c]	—	—	—	(10)
Ending balance	$ (2)	$ —	$ (2,890)	$ (29)	$ —	$ (2,921)
Generation[a]						
Beginning balance	$ (16)	$ 3	$ —	$ (23)	$ (1)	$ (37)
OCI before reclassifications	13	—	—	(6)	1	8
Amounts reclassified from AOCI[b]	(1)	—	—	—	—	(1)
Net current-period OCI	12	—	—	(6)	1	7
Impact of adoption of Recognition and Measurement of Financial Assets and Liabilities standard	—	(3) [c]	—	—	—	(3)
Ending balance	$ (4)	$ —	$ —	$ (29)	$ —	$ (33)
PECO[a]						
Beginning balance	$ —	$ 1	$ —	$ —	$ —	$ 1
OCI before reclassifications	—	—	—	—	—	—
Amounts reclassified from AOCI[b]	—	—	—	—	—	—
Net current-period OCI	—	—	—	—	—	—
Impact of adoption of Recognition and Measurement of Financial Assets and Liabilities standard	—	(1) [c]	—	—	—	(1)
Ending balance	$ —	$ —	$ —	$ —	$ —	$—

150

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Six Months Ended June 30, 2017	Gains (Losses) on Cash Flow Hedges	Unrealized gains (losses) on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan Items	Foreign Currency Items	AOCI of Investments in Unconsolidated Affiliates	Total
Exelon[(a)]						
Beginning balance	$ (17)	$ 4	$ (2,610)	$ (30)	$ (7)	$(2,660)
OCI before reclassifications	1	2	(58)	3	5	(47)
Amounts reclassified from AOCI[(b)]	4	—	70	—	—	74
Net current-period OCI	5	2	12	3	5	27
Ending balance	$ (12)	$ 6	$ (2,598)	$ (27)	$ (2)	$(2,633)
Generation[(a)]						
Beginning balance	$ (19)	$ 2	$ —	$ (30)	$ (7)	$(54)
OCI before reclassifications	1	—	—	3	6	10
Amounts reclassified from AOCI[(b)]	4	—	—	—	—	4
Net current-period OCI	5	—	—	3	6	14
Ending balance	$ (14)	$ 2	$ —	$ (27)	$ (1)	$(40)
PECO[(a)]						
Beginning balance	$ —	$ 1	$ —	$ —	$ —	$1
OCI before reclassifications	—	—	—	—	—	—
Amounts reclassified from AOCI[(b)]	—	—	—	—	—	—
Net current-period OCI	—	—	—	—	—	—
Ending balance	$ —	$ 1	$ —	$ —	$ —	$1

(a) All amounts are net of tax and noncontrolling interests. Amounts in parenthesis represent a decrease in AOCI.
(b) See next tables for details about these reclassifications.
(c) Exelon prospectively adopted the new standard Recognition and Measurement of Financial Assets and Liabilities. The standard was adopted as of January 1, 2018, which resulted in an increase to Retained earnings and Accumulated other comprehensive loss of $10 million, $3 million and $1 million for Exelon, Generation and PECO, respectively. The amounts reclassified related to Rabbi Trusts. See Note 2 — New Accounting Standards for additional information.
(d) Exelon early adopted the new standard Reclassification of Certain Tax Effects from AOCI. The standard was adopted retrospectively as of December 31, 2017, which resulted in an increase to Exelon's Retained earnings and Accumulated other comprehensive loss of $539 million, primarily related to deferred income taxes associated with Exelon's pension and OPEB obligations. See Note 2 — New Accounting Standards for additional information.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

ComEd, PECO, BGE, PHI, Pepco, DPL and ACE did not have any reclassifications out of AOCI to Net income during the three and six months ended June 30, 2018 and 2017. The following tables present amounts reclassified out of AOCI to Net income for Exelon and Generation during the three and six months ended June 30, 2018 and 2017.
Three Months Ended June 30, 2018

Details about AOCI components	Items reclassified out of AOCI[a]		Affected line item in the Statement of Operations and Comprehensive Income
	Exelon	Generation	
Gains (Losses) on cash flow hedges			
Other cash flow hedges	$ 1	$ 1	Interest expense
Total before tax	1	1	
Tax benefit	—	—	
Net of tax	$ 1	$ 1	Comprehensive income
Amortization of pension and other postretirement benefit plan items			
Prior service costs[b]	$ 23	$ —	
Actuarial losses[b]	(83)	—	
Total before tax	(60)	—	
Tax benefit	16	—	
Net of tax	$ (44)	$ —	
Total Reclassifications	$ (43)	$ 1	Comprehensive income

152

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Six Months Ended June 30, 2018

Details about AOCI components	Items reclassified out of AOCI[a]		Affected line item in the Statement of Operations and Comprehensive Income
	Exelon	Generation	
Gains (Losses) on cash flow hedges			
Other cash flow hedges	$ 1	$ 1	Interest expense
Total before tax	1	1	
Tax benefit	—	—	
Net of tax	$ 1	$ 1	Comprehensive income
Amortization of pension and other postretirement benefit plan items			
Prior service costs[b]	$ 46	$ —	
Actuarial losses[b]	(166)	—	
Total before tax	(120)	—	
Tax benefit	32	—	
Net of tax	$ (88)	$ —	
Total Reclassifications	$ (87)	$ 1	Comprehensive income

Three Months Ended June 30, 2017

Details about AOCI components	Items reclassified out of AOCI[a]	Affected line item in the Statement of Operations and Comprehensive Income
	Exelon	
Amortization of pension and other postretirement benefit plan items		
Prior service costs[b]	$ 23	
Actuarial losses[b]	(81)	
Total before tax	(58)	
Tax benefit	24	
Net of tax	$ (34)	
Total Reclassifications	$ (34)	Comprehensive income

153

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Six Months Ended June 30, 2017

Details about AOCI components	Items reclassified out of AOCI[a]		Affected line item in the Statement of Operations and Comprehensive Income
	Exelon	Generation	
Gains (Losses) on cash flow hedges			
Other cash flow hedges	$ (7)	$ (7)	Interest expense
Total before tax	(7)	(7)	
Tax benefit	3	3	
Net of tax	$ (4)	$ (4)	Comprehensive income
Amortization of pension and other postretirement benefit plan items			
Prior service costs[b]	$ 46	$ —	
Actuarial losses[b]	(162)	—	
Total before tax	(116)	—	
Tax benefit	46	—	
Net of tax	$ (70)	$ —	
Total Reclassifications	$ (74)	$ (4)	Comprehensive income

(a) Amounts in parenthesis represent a decrease in net income.
(b) This AOCI component is included in the computation of net periodic pension and OPEB cost (see Note 14 — Retirement Benefits for additional information).

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

The following table presents income tax expense (benefit) allocated to each component of other comprehensive income (loss) during the three and six months ended June 30, 2018 and 2017:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Exelon				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	$6	$9	$12	$18
Actuarial loss reclassified to periodic benefit cost	(22)	(32)	(44)	(64)
Pension and non-pension postretirement benefit plans valuation adjustment	1	1	(6)	3
Change in unrealized (loss) on cash flow hedges	(1)	(2)	(4)	(3)
Change in unrealized (loss) on investments in unconsolidated affiliates	—	—	(1)	(3)
Change in unrealized (loss) on marketable securities	—	—	—	(1)
Total	$(16)	$(24)	$(43)	$(50)
Generation				
Change in unrealized (loss) on cash flow hedges	$(1)	$(2)	$(4)	$(3)
Change in unrealized (loss) on investments in unconsolidated affiliates	—	—	(1)	(2)
Total	$(1)	$(2)	$(5)	$(5)

16. Earnings Per Share and Equity (Exelon)

Earnings per Share

Basic earnings per share is computed by dividing net income attributable to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings per share is computed by dividing net income attributable to common shareholders by the weighted average number of common shares outstanding, including the effect of issuing common stock assuming (i) stock options are exercised, and (ii) performance share awards and restricted stock awards are fully vested under the treasury stock method.

The following table sets forth the components of basic and diluted earnings per share and shows the effect of these stock options, performance share awards and restricted stock awards on the weighted average number of shares outstanding used in calculating diluted earnings per share:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Exelon				
Net income attributable to common shareholders	$539	$95	$1,125	$1,086
Weighted average common shares outstanding — basic	967	934	967	931
Assumed exercise and/or distributions of stock-based awards	2	2	1	1
Weighted average common shares outstanding — diluted	969	936	968	932

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 2 million and 5 million for the three and six months ended June 30, 2018, respectively, and 8 million and 9 million for the three and six months ended June 30, 2017, respectively. There were no equity units related to the PHI Merger not included in the calculation of diluted common shares outstanding due to their antidilutive effect for the three and six months ended June 30, 2018 and 2017. See Note 19 — Shareholders' Equity of the Exelon 2017 Form 10-K for additional information regarding the equity units.

Under share repurchase programs, 2 million shares of common stock are held as treasury stock with a cost of $123 million as of June 30, 2018.

17. Commitments and Contingencies (All Registrants)

The following is an update to the current status of commitments and contingencies set forth in Note 23 of the Exelon 2017 Form 10-K. See Note 4 — Mergers, Acquisitions and Dispositions of the Exelon 2017 Form 10-K for additional information on the PHI Merger commitments.

Commitments

PHI Merger Commitments (Exelon, PHI, Pepco, DPL and ACE)

The merger of Exelon and PHI was approved in Delaware, New Jersey, Maryland and the District of Columbia. Exelon and PHI agreed to certain commitments including where applicable: customer rate credits, funding for energy efficiency and delivery system modernization programs, a green sustainability fund, workforce development initiatives, charitable contributions, renewable generation and other required commitments. In addition, the orders approving the merger in Delaware, New Jersey, and Maryland include a “most favored nation” provision which, generally, requires allocation of merger benefits proportionally across all the jurisdictions.

The following amounts represent total commitment costs for Exelon, PHI, Pepco, DPL and ACE that have been recorded since the acquisition date and the remaining obligations as of June 30, 2018:

Description	Expected Payment Period	Pepco	DPL	ACE	PHI	Exelon
Rate credits	2016 - 2017	$ 91	$ 67	$ 101	$ 259	$ 259
Energy efficiency	2016 - 2021	—	—	—	—	122
Charitable contributions	2016 - 2026	28	12	10	50	50
Delivery system modernization	Q2 2017	—	—	—	—	22
Green sustainability fund	Q2 2017	—	—	—	—	14
Workforce development	2016 - 2020	—	—	—	—	17
Other		1	5	—	6	29
Total commitments		$ 120	$ 84	$ 111	$ 315	$ 513
Remaining commitments		$ 76	$ 12	$ 7	$ 95	$ 140

In addition, Exelon is committed to develop or to assist in the commercial development of approximately 37 MWs of new generation in Maryland, District of Columbia, and Delaware, 27 MWs of which are expected to be completed in 2018. These investments are expected to total approximately $137 million, are expected to be primarily capital in nature, and will generate future earnings at Exelon and Generation. Investment costs will be recognized as incurred and recorded on Exelon's and Generation's financial statements. Exelon has also committed to purchase 100 MWs of wind energy in PJM, to procure 120 MWs of wind RECs for the purpose of meeting Delaware's renewable portfolio

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

standards, and to maintain and promote energy efficiency and demand response programs in the PHI jurisdictions. Pursuant to the various jurisdictions' merger approval conditions, over specified periods Pepco, DPL and ACE are not permitted to reduce employment levels due to involuntary attrition associated with the merger integration process and have made other commitments regarding hiring and relocation of positions.

Constellation Merger Commitments (Exelon and Generation)

In February 2012, the MDPSC issued an Order approving the Exelon and Constellation merger. As part of the MDPSC Order, Exelon agreed to develop or assist in the development of 285-300 MWs of new generation. Exelon and Generation have incurred $458 million towards satisfying the commitment for new generation development in the State of Maryland, with 220 MW of new generation in operations to date and 10 MW of this commitment satisfied through a liquidated damages payment made in the fourth quarter of 2016. The remaining 55 MW is expected to be satisfied via payment of liquidated damages or execution of a third party PPA, rather than by Generation constructing renewable generating assets. As a result, as of June 30, 2018 Exelon’s and Generation’s Consolidated Balance Sheets include a $50 million liability within Deferred credits and other liabilities for this remaining commitment, to be paid on or before January 15, 2023 unless the period is extended by consent of Exelon and the State of Maryland. See Note 23 - Commitments and Contingencies of the Exelon 2017 Form 10-K for additional information regarding the Constellation Merger Commitments.

Commercial Commitments (All Registrants)

The Registrants’ commercial commitments as of June 30, 2018, representing commitments potentially triggered by future events were as follows:

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Letters of credit (non-debt)[(a)]	$1,573	$ 1,543	$ 2	$ —	$ 3	$—	$ —	$—	$ —
Surety bonds[(b)]	1,395	1,202	9	9	18	65	32	4	3
Financing trust guarantees	378	—	200	178	—	—	—	—	—
Guaranteed lease residual values[(c)]	22	—	—	—	—	22	7	9	6
Total commercial commitments	$3,368	$ 2,745	$ 211	$ 187	$ 21	$87	$ 39	$ 13	$ 9

(a) Letters of credit (non-debt) - Exelon and certain of its subsidiaries maintain non-debt letters of credit to provide credit support for certain transactions as requested by third parties. Includes letters of credits issued under credit facility agreements arranged at minority and community banks and nonrecourse debt letters of credits.

(b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.

(c) Represents the maximum potential obligation in the event that the fair value of certain leased equipment and fleet vehicles is zero at the end of the maximum lease term. The maximum lease term associated with these assets ranges from 3 to 8 years. The maximum potential obligation at the end of the minimum lease term would be $58 million, $17 million of which is a guarantee by Pepco, $24 million by DPL and $16 million by ACE. The minimum lease term associated with these assets ranges from 1 to 4 years. Historically, payments under the guarantees have not been made and PHI believes the likelihood of payments being required under the guarantees is remote.

Nuclear Insurance (Exelon and Generation)

Generation is subject to liability, property damage and other risks associated with major incidents at any of its nuclear stations. Generation has mitigated its financial exposure to these risks through insurance and other industry risk-sharing provisions.

157

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

The Price-Anderson Act was enacted to ensure the availability of funds for public liability claims arising from an incident at any of the U.S. licensed nuclear facilities and also to limit the liability of nuclear reactor owners for such claims from any single incident. As of June 30, 2018, the current liability limit per incident is $13.1 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors. Changes to account for the effects of inflation occur at least once every five years with the last adjustment effective September 10, 2013. In accordance with the Price-Anderson Act, Generation maintains financial protection at levels equal to the amount of liability insurance available from private sources through the purchase of private nuclear energy liability insurance for public liability claims that could arise in the event of an incident. Effective January 1, 2017, the required amount of nuclear energy liability insurance purchased is $450 million for each operating site. Claims exceeding that amount are covered through mandatory participation in a financial protection pool, as required by the Price Anderson-Act, which provides the additional $12.6 billion per incident in funds available for public liability claims. Participation in this secondary financial protection pool requires the operator of each reactor to fund its proportionate share of costs for any single incident that exceeds the primary layer of financial protection. Exelon’s share of this secondary layer would be approximately $2.8 billion, however any amounts payable under this secondary layer would be capped at $420 million per year.

In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay public liability claims exceeding the $13.1 billion limit for a single incident.

As part of the execution of the NOSA on April 1, 2014, Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF and its affiliates against third-party claims that may arise from any future nuclear incident (as defined in the Price-Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation’s obligations under this indemnity. See Note 2 — Variable Interest Entities of the Exelon 2017 Form 10-K for additional information on Generation’s operations relating to CENG.

Generation is required each year to report to the NRC the current levels and sources of property insurance that demonstrates Generation possesses sufficient financial resources to stabilize and decontaminate a reactor and reactor station site in the event of an accident. The property insurance maintained for each facility is currently provided through insurance policies purchased from NEIL, an industry mutual insurance company of which Generation is a member.

NEIL may declare distributions to its members as a result of favorable operating experience. In recent years NEIL has made distributions to its members, but Generation cannot predict the level of future distributions or if they will continue at all. In March 2018, NEIL declared a supplemental distribution. Generation's portion of the supplemental distribution declared by NEIL was $31 million and was recorded as a reduction to Operating and maintenance expense within Exelon and Generation’s Consolidated Statements of Operations and Comprehensive Income for the six months ended June 30, 2018.

Premiums paid to NEIL by its members are also subject to a potential assessment for adverse loss experience in the form of a retrospective premium obligation. NEIL has never assessed this retrospective premium since its formation in 1973, and Generation cannot predict the level of future assessments if any. The current maximum aggregate annual retrospective premium obligation for Generation is approximately $350 million. NEIL requires its members to maintain an investment grade credit rating or to ensure collectability of their annual retrospective premium obligation by providing a financial guarantee, letter of credit, deposit premium, or some other means of assurance.

NEIL provides “all risk” property damage, decontamination and premature decommissioning insurance for each station for losses resulting from damage to its nuclear plants, either due to accidents or acts of terrorism. If the decision is made to decommission the facility, a portion of the insurance proceeds will be allocated to a fund, which Generation is required by the NRC to maintain, to provide for decommissioning the facility. In the event of an insured loss, Generation is unable to predict the timing

of the availability of insurance proceeds to Generation and the amount of such proceeds that would be available. In the event that one or more acts of terrorism cause accidental property damage within a twelve-month period from the first accidental property damage under one or more policies for all insured plants, the maximum recovery by Exelon will be an aggregate of $3.2 billion plus such additional amounts as the insurer may recover for all such losses from reinsurance, indemnity and any other source, applicable to such losses.

For its insured losses, Generation is self-insured to the extent that losses are within the policy deductible or exceed the amount of insurance maintained. Uninsured losses and other expenses, to the extent not recoverable from insurers or the nuclear industry, could also be borne by Generation. Any such losses could have a material adverse effect on Exelon’s and Generation’s financial condition, results of operations and cash flows.

Environmental Remediation Matters

General (All Registrants)

The Registrants’ operations have in the past, and may in the future, require substantial expenditures to comply with environmental laws. Additionally, under Federal and state environmental laws, the Registrants are generally liable for the costs of remediating environmental contamination of property now or formerly owned by them and of property contaminated by hazardous substances generated by them. The Registrants own or lease a number of real estate parcels, including parcels on which their operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. In addition, the Registrants are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future. Unless otherwise disclosed, the Registrants cannot reasonably estimate whether they will incur significant liabilities for additional investigation and remediation costs at these or additional sites identified by the Registrants, environmental agencies or others, or whether such costs will be recoverable from third parties, including customers. Additional costs could have a material, unfavorable impact on the Registrants' financial conditions, results of operations and cash flows.

MGP Sites (Exelon, ComEd, PECO, BGE, PHI and DPL)

ComEd, PECO, BGE and DPL have identified sites where former MGP or gas purification activities have or may have resulted in actual site contamination. For almost all of these sites, there are additional PRPs that may share responsibility for the ultimate remediation of each location.

- ComEd has identified 42 sites, 20 of which have been remediated and approved by the Illinois EPA or the U.S. EPA and 22 that are currently under some degree of active study and/or remediation. ComEd expects the majority of the remediation at these sites to continue through at least 2022.
- PECO has identified 26 sites, 17 of which have been remediated in accordance with applicable PA DEP regulatory requirements and 9 that are currently under some degree of active study and/or remediation. PECO expects the majority of the remediation at these sites to continue through at least 2022.
- BGE has identified 13 sites, 9 of which have been remediated and approved by the MDE and 4 that require some level of remediation and/or ongoing activity. BGE expects the majority of the remediation at these sites to continue through at least 2019.
- DPL has identified 3 sites, for 2 of which remediation has been completed and approved by the MDE or the Delaware Department of Natural Resources and Environmental Control.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

The remaining site is under study and the required cost at the site is not expected to be material.
The historical nature of the MGP and gas purification sites and the fact that many of the sites have been buried and built over, impacts the ability to determine a precise estimate of the ultimate costs prior to initial sampling and determination of the exact scope and method of remedial activity. Management determines its best estimate of remediation costs using all available information at the time of each study, including probabilistic and deterministic modeling for ComEd and PECO, and the remediation standards currently required by the applicable state environmental agency. Prior to completion of any significant clean up, each site remediation plan is approved by the appropriate state environmental agency.
ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC, are currently recovering environmental remediation costs of former MGP facility sites through customer rates. See Note 6 — Regulatory Matters for additional information regarding the associated regulatory assets. While BGE and DPL do not have riders for MGP clean-up costs, they have historically received recovery of actual clean-up costs in distribution rates.
As of June 30, 2018 and December 31, 2017, the Registrants had accrued the following undiscounted amounts for environmental liabilities in Other current liabilities and Other deferred credits and other liabilities within their respective Consolidated Balance Sheets:

June 30, 2018	Total environmental investigation and remediation reserve	Portion of total related to MGP investigation and remediation
Exelon	$ 453	$ 305
Generation	115	—
ComEd	276	274
PECO	28	27
BGE	6	4
PHI	28	—
Pepco	26	—
DPL	1	—
ACE	1	—

December 31, 2017	Total environmental investigation and remediation reserve	Portion of total related to MGP investigation and remediation
Exelon	$ 466	$ 315
Generation	117	—
ComEd	285	283
PECO	30	28
BGE	5	4
PHI	29	—
Pepco	27	—
DPL	1	—
ACE	1	—

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Solid and Hazardous Waste
Cotter Corporation (Exelon and Generation)
The EPA has advised Cotter Corporation (Cotter), a former ComEd subsidiary, that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Missouri. In 2000, ComEd sold Cotter to an unaffiliated third-party. As part of the sale, ComEd agreed to indemnify Cotter for any liability arising in connection with the West Lake Landfill. In connection with Exelon’s 2001 corporate restructuring, this responsibility to indemnify Cotter was transferred to Generation. On May 29, 2008, the EPA issued a Record of Decision (ROD) approving a landfill cover remediation approach. Generation had previously recorded an estimated liability for its anticipated share of a landfill cover remedy that was estimated to cost approximately $90 million in total. By letter dated January 11, 2010, the EPA requested that the PRPs perform a supplemental feasibility study for a remediation alternative that would involve complete excavation of the radiological contamination. On September 30, 2011, the PRPs submitted the supplemental feasibility study to the EPA for review. Since June 2012, the EPA has requested that the PRPs perform a series of additional analyses and groundwater and soil sampling as part of the supplemental feasibility study. This further analysis was focused on a partial excavation remedial option. The PRPs provided the draft final Remedial Investigation and Feasibility Study (RI/FS) to the EPA in January 2018, which formed the basis for EPA’s proposed remedy selection, as discussed below. There are currently three PRPs participating in the West Lake Landfill remediation proceeding. Investigation by Generation has identified a number of other parties who also may be PRPs and could be liable to contribute to the final remedy. Further investigation is ongoing.
On February 1, 2018, the EPA announced its proposed remedy involving partial excavation of the site with an enhanced landfill cover. The proposed remedy was open for public comment through April 23, 2018 and Generation currently expects that a ROD will be issued during the third quarter of 2018. Thereafter, the EPA will seek to enter into a Consent Decree with the PRPs to effectuate the remedy, which Generation currently expects will occur in late 2018 or early 2019. The estimated cost of the remedy, taking into account the current EPA technical requirements and the total costs expected to be incurred by the PRPs in fully executing the remedy, is approximately $340 million, including cost escalation on an undiscounted basis, which would be allocated among the final group of PRPs. Generation has determined that a loss associated with the EPA’s partial excavation and enhanced landfill cover remedy is probable and has recorded a liability included in the table above, that reflects management’s best estimate of Cotter’s allocable share of the ultimate cost for the entire remediation effort. Given the joint and several nature of this liability, the magnitude of Generation’s ultimate liability will depend on the actual costs incurred to implement the ultimate required remediation remedy as well as on the nature and terms of any cost-sharing arrangements with the final group of PRPs. Therefore, it is reasonably possible that the ultimate cost and Generation’s associated allocable share could differ significantly once these uncertainties are resolved, which could have a material impact on Exelon's and Generation's future financial conditions, results of operations and cash flows.
On January 16, 2018, the PRPs were advised by the EPA that it will begin an additional investigation and evaluation of groundwater conditions at the West Lake Landfill. The PRPs have been provided with a draft statement of work that will form the basis of an Administrative Settlement Agreement and Order on Consent for the performance by the PRPs of the groundwater RI/FS and reimbursement of EPA’s oversight costs. The purposes of this new RI/FS are to define the nature and extent of any groundwater contamination from the West Lake Landfill site, determine the potential risk posed to human health and the environment, and evaluate remedial alternatives. Generation estimates the undiscounted cost for the groundwater RI/FS for West Lake to be approximately $20 million and Generation has recorded a liability included in the table above, that reflects management’s best estimate of Cotter’s allocable share of the cost among the PRPs. At this time Generation cannot predict the likelihood or the extent to which, if any, remediation activities will be required and cannot estimate a reasonably possible range of loss for response costs beyond those associated with the RI/FS component. It is reasonably possible,

161

Table of Contents

however, that resolution of this matter could have a material, unfavorable impact on Exelon’s and Generation’s future results of operations and cash flows.

During December 2015, the EPA took two actions related to the West Lake Landfill designed to abate what it termed as imminent and dangerous conditions at the landfill. The first involved installation by the PRPs of a non-combustible surface cover to protect against surface fires in areas where radiological materials are believed to have been disposed. Generation has accrued what it believes to be an adequate amount to cover its anticipated liability for this interim action, and the work is expected to be completed in 2018. The second action involved EPA's public statement that it will require the PRPs to construct a barrier wall in an adjacent landfill to prevent a subsurface fire from spreading to those areas of the West Lake Landfill where radiological materials are believed to have been disposed. At this time, Generation believes that the requirement to build a barrier wall is remote in light of other technologies that have been employed by the adjacent landfill owner. Finally, one of the other PRPs, the landfill owner and operator of the adjacent landfill, has indicated that it will be making a contribution claim against Cotter for costs that it has incurred to prevent the subsurface fire from spreading to those areas of the West Lake Landfill where radiological materials are believed to have been disposed. At this time, Exelon and Generation do not possess sufficient information to assess this claim and therefore are unable to estimate a range of loss, if any. As such, no liability has been recorded for the potential contribution claim. It is reasonably possible, however, that resolution of this matter could have a material, unfavorable impact on Exelon’s and Generation's financial conditions, results of operations and cash flows.

On August 8, 2011, Cotter was notified by the DOJ that Cotter is considered a PRP with respect to the government’s clean-up costs for contamination attributable to low level radioactive residues at a former storage and reprocessing facility named Latty Avenue near St. Louis, Missouri. The Latty Avenue site is included in ComEd’s indemnification responsibilities discussed above as part of the sale of Cotter. The radioactive residues had been generated initially in connection with the processing of uranium ores as part of the U.S. Government’s Manhattan Project. Cotter purchased the residues in 1969 for initial processing at the Latty Avenue facility for the subsequent extraction of uranium and metals. In 1976, the NRC found that the Latty Avenue site had radiation levels exceeding NRC criteria for decontamination of land areas. Latty Avenue was investigated and remediated by the United States Army Corps of Engineers pursuant to funding under FUSRAP. The DOJ has not yet formally advised the PRPs of the amount that it is seeking, but it is believed to be approximately $90 million from all PRPs. The DOJ and the PRPs agreed to toll the statute of limitations until August 2018 so that settlement discussions could proceed. Generation has determined that a loss associated with this matter is probable under its indemnification agreement with Cotter and has recorded an estimated liability, which is included in the table above.

Commencing in February 2012, a number of lawsuits have been filed in the U.S. District Court for the Eastern District of Missouri. Among the defendants were Exelon, Generation and ComEd, all of which were subsequently dismissed from the case, as well as Cotter, which remains a defendant. The suits allege that individuals living in the North St. Louis area developed some form of cancer or other serious illness due to Cotter's negligent or reckless conduct in processing, transporting, storing, handling and/or disposing of radioactive materials. Plaintiffs are asserting public liability claims under the Price-Anderson Act. Their state law claims for negligence, strict liability, emotional distress, and medical monitoring have been dismissed. In the event of a finding of liability against Cotter, it is probable that Generation would be financially responsible due to its indemnification responsibilities of Cotter described above. The court has dismissed a number of the lawsuits as untimely, which has been upheld on appeal. Cotter and the remaining plaintiffs have engaged in settlement discussions pursuant to court-ordered mediation. During the second quarter of 2018, Generation determined a loss was probable based on the advancement of settlement proceedings and recorded an immaterial liability.

Table of Contents

Benning Road Site (Exelon, Generation, PHI and Pepco)

In September 2010, PHI received a letter from EPA identifying the Benning Road site as one of six land-based sites potentially contributing to contamination of the lower Anacostia River. A portion of the site was formerly the location of a Pepco Energy Services electric generating facility. That generating facility was deactivated in June 2012 and plant structure demolition was completed in July 2015. The remaining portion of the site consists of a Pepco transmission and distribution service center that remains in operation. In December 2011, the U.S. District Court for the District of Columbia approved a Consent Decree entered into by Pepco and Pepco Energy Services with the DOEE, which requires Pepco and Pepco Energy Services to conduct a Remediation Investigation (RI)/ Feasibility Study (FS) for the Benning Road site and an approximately 10 to 15-acre portion of the adjacent Anacostia River. The RI/FS will form the basis for the remedial actions for the Benning Road site and for the Anacostia River sediment associated with the site. The Consent Decree does not obligate Pepco or Pepco Energy Services to pay for or perform any remediation work, but it is anticipated that DOEE will look to Pepco and Pepco Energy Services to assume responsibility for cleanup of any conditions in the river that are determined to be attributable to past activities at the Benning Road site. Pursuant to Exelon's March 23, 2016 acquisition of PHI, Pepco Energy Services was transferred to Generation.

Since 2013, Pepco and Pepco Energy Services (now Generation) have been performing RI work and have submitted multiple draft RI reports to the DOEE. Once the RI work is completed, Pepco and Generation will issue a draft "final" RI report for review and comment by DOEE and the public. Pepco and Generation will then proceed to develop an FS to evaluate possible remedial alternatives for submission to DOEE. The Court has established a schedule for completion of the RI and FS, and approval by the DOEE, by May 6, 2019.

Upon DOEE's approval of the final RI and FS Reports, Pepco and Generation will have satisfied their obligations under the Consent Decree. At that point, DOEE will prepare a Proposed Plan regarding further response actions. After considering public comment on the Proposed Plan, DOEE will issue a Record of Decision identifying any further response actions determined to be necessary.

PHI, Pepco and Generation have determined that a loss associated with this matter is probable and have accrued an estimated liability, which is included in the table above.

Anacostia River Tidal Reach (Exelon, PHI and Pepco)

Contemporaneous with the Benning RI/FS being performed by Pepco and Generation, DOEE and certain federal agencies have been conducting a separate RI/FS focused on the entire tidal reach of the Anacostia River extending from just north of the Maryland-D.C. boundary line to the confluence of the Anacostia and Potomac Rivers. In March 2016, DOEE released a draft of the river-wide RI Report for public review and comment. The river-wide RI incorporated the results of the river sampling performed by Pepco and Pepco Energy Services as part of the Benning RI/FS, as well as similar sampling efforts conducted by owners of other sites adjacent to this segment of the river and supplemental river sampling conducted by DOEE's contractor. DOEE asked Pepco, along with parties responsible for other sites along the river, to participate in a "Consultative Working Group" to provide input into the process for future remedial actions addressing the entire tidal reach of the river and to ensure proper coordination with the other river cleanup efforts currently underway, including cleanup of the river segment adjacent to the Benning Road site resulting from the Benning RI/FS. Pepco responded that it will participate in the Consultative Working Group, but its participation is not an acceptance of any financial responsibility beyond the work that will be performed at the Benning Road site described above. In April 2018, DOEE released a draft remedial investigation report for public review and comment. Pepco submitted written comments to the draft RI and participated in a public hearing. Pepco continues outreach efforts as appropriate to the agencies, governmental officials, community organizations and other key stakeholders. A draft Feasibility Study of potential remedies is being prepared by the agencies and is scheduled to be released later this year. In May 2018 the District of Columbia Council extended the deadline for completion

Table of Contents

of the Record of Decision from June 30, 2018 until December 31, 2019. An appropriate liability for Pepco's share of investigation costs has been accrued and is included in the table above. Although Pepco has determined that it is probable that costs for remediation will be incurred, Pepco cannot estimate the reasonably possible range of loss at this time and no liability has been accrued for those future costs. It is anticipated that Pepco will likely be in a better position to estimate that range of loss when the draft Feasibility Study for the Project is released later this year.

In addition to the activities associated with the remedial process outlined above, there is a complementary statutory program that requires an assessment to determine if any natural resources have been damaged as a result of the contamination that is being remediated, and, if so, that a plan be developed by the federal, state and local Trustees responsible for those resources to restore them to their condition before injury from the environmental contaminants. If natural resources are not restored, then compensation for the injury can be sought from the party responsible for the release of the contaminants. The assessment of Natural Resource Damages (NRD) typically takes place following cleanup because cleanups sometimes also effectively restore habitat. During the second quarter of 2018, Pepco became aware that the Trustees are in the beginning stages of this process that often takes many years beyond the remedial decision to complete. Pepco has concluded that a loss associated with the eventual NRD assessment is reasonably possible. Due to the very early stage of the assessment process it cannot reasonably estimate the range of loss.

Conectiv Energy Wholesale Power Generation Sites (Exelon, Generation, and PHI)

In July 2010, PHI sold the wholesale power generation business of Conectiv Energy Holdings, Inc. and substantially all of its subsidiaries (Conectiv Energy) to Calpine Corporation (Calpine). Under New Jersey's Industrial Site Recovery Act (ISRA), the transfer of ownership triggered an obligation on the part of Conectiv Energy to remediate any environmental contamination at each of the nine Conectiv Energy generating facility sites located in New Jersey. Under the terms of the sale, Calpine has assumed responsibility for performing the ISRA-required remediation and for the payment of all related ISRA compliance costs up to $10 million. PHI indemnified Calpine for any ISRA compliance remediation costs in excess of $10 million. PHI estimated the costs of ISRA-required remediation activities at the nine generating facility sites located in New Jersey are in the range of approximately $7 million to $18 million and recorded a liability for its share of the estimated clean-up costs. Pursuant to Exelon's March 2016 acquisition of PHI, the Conectiv Energy legal entity was transferred to Generation and the liability for PHI's share of the estimated clean-up costs was also transferred to Generation and is included in the table above as a liability of Generation. The responsibility to indemnify Calpine is shared by PHI and Generation.

Brandywine Fly Ash Disposal Site (Exelon, PHI and Pepco)

In February 2013, Pepco received a letter from the MDE requesting that Pepco investigate the extent of waste on a Pepco right-of-way that traverses the Brandywine fly ash disposal site in Brandywine, Prince George's County, Maryland, owned by NRG Energy, Inc. (as successor to GenOn MD Ash Management, LLC) (NRG). In July 2013, while reserving its rights and related defenses under a 2000 agreement covering the sale of this site, Pepco indicated its willingness to investigate the extent of, and propose an appropriate closure plan to address, ash on the right-of-way. Pepco submitted a schedule for development of a closure plan to MDE on September 30, 2013 and, by letter dated October 18, 2013, MDE approved the schedule.

Pepco has determined that a loss associated with this matter is probable and has recorded an estimated liability, which is included in the table above. Pepco believes that the costs incurred in this matter may be recoverable from NRG under the 2000 sale agreement but has not recorded an associated receivable for any potential recovery.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Litigation and Regulatory Matters

PHI Merger (Exelon and PHI)

In July 2015, the OPC, Public Citizen, Inc., the Sierra Club and the Chesapeake Climate Action Network (CCAN) filed motions to stay the MDPSC order approving the Exelon and PHI merger. The Circuit Court judge issued an order denying the motions for stay on August 12, 2015. On January 8, 2016, the Circuit Court judge affirmed the MDPSC's order approving the merger and denied the petitions for judicial review filed by the OPC, the Sierra Club, CCAN and Public Citizen, Inc. On January 19, 2016, the OPC filed a notice of appeal to the Maryland Court of Special Appeals, and on January 21, the Sierra Club and CCAN filed notices of appeal. On January 27, 2017, the Maryland Court of Special Appeals affirmed the Circuit Court's judgment that the MDPSC did not err in approving the merger. The OPC and Sierra Club filed petitions seeking further review in the Court of Appeals of Maryland, which is the highest court in Maryland. On June 21, 2017, the Court of Appeals granted discretionary review of the January 27, 2017 decision by the Maryland Court of Special Appeals. The Maryland Court of Appeals will review the OPC argument that the MDPSC did not properly consider the acquisition premium paid to PHI shareholders under Maryland's merger approval standard and the Sierra Club's argument that the merger would harm the renewable and distributed generation markets. The two lower courts examining these issues rejected these arguments, which Exelon believes are without merit. All briefs have been filed and oral arguments were presented to the court on October 10, 2017.

Asbestos Personal Injury Claims (Exelon, Generation, PECO and ComEd)

Generation maintains a reserve for claims associated with asbestos-related personal injury actions in certain facilities that are currently owned by Generation or were previously owned by ComEd and PECO. The estimated liabilities are recorded on an undiscounted basis and exclude the estimated legal costs associated with handling these matters, which could be material.

At June 30, 2018 and December 31, 2017, Generation had recorded estimated liabilities of approximately $80 million and $78 million, respectively, in total for asbestos-related bodily injury claims. As of June 30, 2018, approximately $22 million of this amount related to 224 open claims presented to Generation, while the remaining $58 million is for estimated future asbestos-related bodily injury claims anticipated to arise through 2050, based on actuarial assumptions and analyses, which are updated on an annual basis. On a quarterly basis, Generation monitors actual experience against the number of forecasted claims to be received and expected claim payments and evaluates whether adjustments to the estimated liabilities are necessary.

There is a reasonable possibility that Exelon may have additional exposure to estimated future asbestos-related bodily injury claims in excess of the amount accrued and the increases could have a material unfavorable impact on Exelon's, Generation's and PECO's financial conditions, results of operations and cash flows.

City of Everett Tax Increment Financing Agreement (Exelon and Generation)

On April 10, 2017, the City of Everett petitioned the Massachusetts Economic Assistance Coordinating Council (EACC) to revoke the 1999 tax increment financing agreement (TIF Agreement) relating to Mystic units 8 and 9 on the grounds that the total investment in Mystic units 8 and 9 materially deviates from the investment set forth in the TIF Agreement. On October 31, 2017, a three-member panel of the EACC conducted an administrative hearing on the City's petition. On November 30, 2017, the hearing panel issued a tentative decision denying the City's petition, finding that there was no material misrepresentation that would justify revocation of the TIF Agreement. On December 13, 2017, the tentative decision was adopted by the full EACC. On January 12, 2018, the City filed a complaint in Massachusetts Superior Court requesting, among other things, that the court set aside the EACC's decision, grant the City's request to decertify the Project and the TIF Agreement, and award the City

Table of Contents

damages for alleged underpaid taxes over the period of the TIF Agreement. Generation vigorously contested the City's claims before the EACC and will continue to do so in the Massachusetts Superior Court proceeding. Generation continues to believe that the City's claim lacks merit. Accordingly, Generation has not recorded a liability for payment resulting from such a revocation, nor can Generation estimate a reasonably possible range of loss, if any, associated with any such revocation. Further, it is reasonably possible that property taxes assessed in future periods, including those following the expiration of the current TIF Agreement in 2019, could be material to Generation's results of operations and cash flows.

General (All Registrants)

The Registrants are involved in various other litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. The Registrants maintain accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of reasonably possible loss, particularly where (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

Income Taxes

See Note 12 — Income Taxes for information regarding the Registrants' income tax refund claims and certain tax positions, including the 1999 sale of fossil generating assets.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

18. Supplemental Financial Information (All Registrants)
Supplemental Statement of Operations Information
The following tables provide additional information about the Registrants' Consolidated Statements of Operations and Comprehensive Income for the three and six months ended June 30, 2018 and 2017.

	Three Months Ended June 30, 2018								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Other, Net									
Decommissioning-related activities:									
Net realized income on decommissioning trust funds[(a)]									
Regulatory agreement units	$216	$ 216	$ —	$ —	$ —	$—	$ —	$ —	$ —
Non-regulatory agreement units	143	143	—	—	—	—	—	—	—
Net unrealized losses on decommissioning trust funds									
Regulatory agreement units	(194)	(194)	—	—	—	—	—	—	—
Non-regulatory agreement units	(120)	(120)	—	—	—	—	—	—	—
Net unrealized gains on pledged assets									
Zion Station decommissioning	4	4	—	—	—	—	—	—	—
Regulatory offset to decommissioning trust fund-related activities[(b)]	(23)	(23)	—	—	—	—	—	—	—
Total decommissioning-related activities	26	26	—	—	—	—	—	—	—
Investment income	6	5	—	—	—	—	—	—	—
Interest income related to uncertain income tax positions	2	—	—	—	—	—	—	—	—
AFUDC — Equity	13	—	2	—	4	7	6	1	—
Non-service net periodic benefit cost	(11)	—	—	—	—	—	—	—	—
Other	8	(2)	2	—	—	4	2	2	1
Other, net	$44	$ 29	$ 4	$ —	$ 4	$11	$ 8	$ 3	$ 1

167

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	Six Months Ended June 30, 2018								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Other, Net									
Decommissioning-related activities:									
Net realized income on decommissioning trust funds[(a)]									
Regulatory agreement units	$262	$ 262	$ —	$ —	$ —	$—	$ —	$ —	$ —
Non-regulatory agreement units	199	199	—	—	—	—	—	—	—
Net unrealized losses on decommissioning trust funds									
Regulatory agreement units	(268)	(268)	—	—	—	—	—	—	—
Non-regulatory agreement units	(215)	(215)	—	—	—	—	—	—	—
Net unrealized gains on pledged assets									
Zion Station decommissioning	2	2	—	—	—	—	—	—	—
Regulatory offset to decommissioning trust fund-related activities[(b)]	(1)	(1)	—	—	—	—	—	—	—
Total decommissioning-related activities	(21)	(21)	—	—	—	—	—	—	—
Investment income	10	7	—	—	—	—	—	—	—
Interest income related to uncertain income tax positions	4	1	—	—	—	—	—	—	—
AFUDC — Equity	31	—	8	2	8	13	12	1	—
Non-service net periodic benefit cost	(21)	—	—	—	—	—	—	—	—
Other	14	(2)	4	—	1	9	4	4	1
Other, net	$17	$ (15)	$ 12	$ 2	$ 9	$22	$ 16	$ 5	$ 1

	Three Months Ended June 30, 2017								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Other, Net									
Decommissioning-related activities:									
Net realized income on decommissioning trust funds[(a)]									
Regulatory agreement units	$211	$ 211	$ —	$ —	$ —	$—	$ —	$ —	$ —
Non-regulatory agreement units	74	74	—	—	—	—	—	—	—
Net unrealized (losses) gains on decommissioning trust funds									
Regulatory agreement units	(13)	(13)	—	—	—	—	—	—	—
Non-regulatory agreement units	70	70	—	—	—	—	—	—	—
Net unrealized losses on pledged assets									
Zion Station decommissioning	(2)	(2)	—	—	—	—	—	—	—
Regulatory offset to decommissioning trust fund-related activities[(b)]	(160)	(160)	—	—	—	—	—	—	—
Total decommissioning-related activities	180	180	—	—	—	—	—	—	—
Investment income	2	1	—	—	—	—	—	—	—
Interest expense related to uncertain income tax positions	(1)	—	—	—	—	—	—	—	—
Penalty income related to uncertain income tax positions	1	—	—	—	—	—	—	—	—
AFUDC — Equity	17	—	2	2	4	9	5	2	2
Non-service net periodic benefit cost	(28)	—	—	—	—	—	—	—	—
Other	6	—	2	—	—	4	2	1	—
Other, net	$177	$ 181	$ 4	$ 2	$ 4	$13	$ 7	$ 3	$ 2

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	Six Months Ended June 30, 2017								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Other, Net									
Decommissioning-related activities:									
Net realized income on decommissioning trust funds[(a)]									
Regulatory agreement units	$280	$ 280	$ —	$ —	$ —	$—	$ —	$ —	$ —
Non-regulatory agreement units	106	106	—	—	—	—	—	—	—
Net unrealized gains on decommissioning trust funds									
Regulatory agreement units	210	210	—	—	—	—	—	—	—
Non-regulatory agreement units	235	235	—	—	—	—	—	—	—
Net unrealized losses on pledged assets									
Zion Station decommissioning	(2)	(2)	—	—	—	—	—	—	—
Regulatory offset to decommissioning trust fund-related activities[(b)]	(396)	(396)	—	—	—	—	—	—	—
Total decommissioning-related activities	433	433	—	—	—	—	—	—	—
Investment income (expense)	4	3	—	(1)	—	1	1	—	—
Penalty income related to uncertain income tax positions	2	—	—	—	—	—	—	—	—
AFUDC — Equity	33	—	4	4	8	17	11	3	3
Non-service net periodic benefit cost	(54)	—	—	—	—	—	—	—	—
Other	16	4	4	—	—	8	3	3	1
Other, net	$434	$ 440	$ 8	$ 3	$ 8	$26	$ 15	$ 6	$ 4

(a) Includes investment income and realized gains and losses on sales of investments of the trust funds.
(b) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of net income taxes related to all NDT fund activity for those units. See Note 15 — Asset Retirement Obligations of the Exelon 2017 Form 10-K for additional information regarding the accounting for nuclear decommissioning.

The following utility taxes are included in revenues and expenses for the three and six months ended June 30, 2018 and 2017. Generation's utility tax expense represents gross receipts tax related to its retail operations, and the Utility Registrants' utility tax expense represents municipal and state utility taxes and gross receipts taxes related to their operating revenues. The offsetting collection of utility taxes from customers is recorded in revenues on the Registrants' Consolidated Statements of Operations and Comprehensive Income.

	Three Months Ended June 30, 2018								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Utility taxes	$218	$ 29	$ 60	$ 30	$ 21	$78	$ 73	$ 5	$ —

	Six Months Ended June 30, 2018								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Utility taxes	$452	$ 60	$ 121	$ 63	$ 47	$161	$ 151	$ 10	$ —

	Three Months Ended June 30, 2017								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Utility taxes	$213	$ 30	$ 57	$ 29	$ 21	$76	$ 72	$ 4	$ —

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	Six Months Ended June 30, 2017								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Utility taxes	$438	$ 63	$ 116	$ 60	$ 47	$152	$143	$ 9	$ —

Supplemental Cash Flow Information

The following tables provide additional information regarding the Registrants' Consolidated Statements of Cash Flows for the six months ended June 30, 2018 and 2017.

	Six Months Ended June 30, 2018								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Depreciation, amortization and accretion									
Property, plant and equipment[(a)]	$1,873	$ 890	$ 406	$ 135	$164	$236	$ 107	$ 64	$ 47
Amortization of regulatory assets[(a)]	278	—	53	14	84	127	81	24	22
Amortization of intangible assets, net[(a)]	28	24	—	—	—	—	—	—	—
Amortization of energy contract assets and liabilities[(b)]	10	10	—	—	—	—	—	—	—
Nuclear fuel[(c)]	569	569	—	—	—	—	—	—	—
ARO accretion[(d)]	242	242	—	—	—	—	—	—	—
Total depreciation, amortization and accretion	$3,000	$ 1,735	$ 459	$ 149	$248	$363	$ 188	$ 88	$ 69

	Six Months Ended June 30, 2017								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Depreciation, amortization and accretion									
Property, plant and equipment[(a)]	$1,545	$ 612	$ 384	$ 129	$155	$227	$ 101	$ 61	$ 44
Amortization of regulatory assets[(a)]	238	—	35	12	84	105	59	18	28
Amortization of intangible assets, net[(a)]	28	25	—	—	—	—	—	—	—
Amortization of energy contract assets and liabilities[(b)]	20	20	—	—	—	—	—	—	—
Nuclear fuel[(c)]	529	529	—	—	—	—	—	—	—
ARO accretion[(d)]	231	229	—	—	—	—	—	—	—
Total depreciation, amortization and accretion	$2,591	$ 1,415	$ 419	$ 141	$239	$332	$ 160	$ 79	$ 72

(a) Included in Depreciation and amortization on the Registrants' Consolidated Statements of Operations and Comprehensive Income.

(b) Included in Operating revenues or Purchased power and fuel expense on the Registrants' Consolidated Statements of Operations and Comprehensive Income.

(c) Included in Purchased power and fuel expense on the Registrants' Consolidated Statements of Operations and Comprehensive Income.

(d) Included in Operating and maintenance expense on the Registrants' Consolidated Statements of Operations and Comprehensive Income.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	Six Months Ended June 30, 2018								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Other non-cash operating activities:									
Pension and non-pension postretirement benefit costs	$290	$ 100	$ 88	$ 10	$29	$34	$ 8	$ 3	$ 6
Loss from equity method investments	12	12	—	—	—	—	—	—	—
Provision for uncollectible accounts	77	28	18	11	5	15	7	2	5
Stock-based compensation costs	47	—	—	—	—	—	—	—	—
Other decommissioning-related activity[(a)]	(61)	(61)	—	—	—	—	—	—	—
Energy-related options[(b)]	(7)	(7)	—	—	—	—	—	—	—
Amortization of regulatory asset related to debt costs	4	—	2	—	—	2	1	1	—
Amortization of rate stabilization deferral	13	—	—	—	—	13	10	3	—
Amortization of debt fair value adjustment	(7)	(6)	—	—	—	(1)	—	—	—
Discrete impacts from EIMA and FEJA[(c)]	14	—	14	—	—	—	—	—	—
Amortization of debt costs	18	7	2	1	1	3	1	—	—
Provision for excess and obsolete inventory	13	12	1	—	—	—	—	—	—
Long-term incentive plan	51	—	—	—	—	—	—	—	—
Other	15	—	(8)	—	(8)	5	(3)	5	1
Total other non-cash operating activities	$479	$ 85	$ 117	$ 22	$27	$71	$ 24	$ 14	$ 12
Non-cash investing and financing activities:									
(Decrease) increase in capital expenditures not paid	$(283)	$ (310)	$ (22)	$(17)	$10	$61	$ 28	$ 17	$ 14
Increase in PPE related to ARO update	47	47	—	—	—	—	—	—	—
Dividends on stock compensation	3	—	—	—	—	—	—	—	—
Acquisition of land	3	—	—	—	—	3	—	—	3

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	Six Months Ended June 30, 2017								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Other non-cash operating activities:									
Pension and non-pension postretirement benefit costs	$320	$ 113	$ 87	$ 14	$ 31	$ 48	$ 13	$ 6	$ 7
Loss from equity method investments	19	19	—	—	—	—	—	—	—
Provision for uncollectible accounts	52	19	15	9	3	6	4	—	2
Stock-based compensation costs	57	—	—	—	—	—	—	—	—
Other decommissioning-related activity[a]	(144)	(144)	—	—	—	—	—	—	—
Energy-related options[b]	11	11	—	—	—	—	—	—	—
Amortization of regulatory asset related to debt costs	4	—	2	—	—	2	1	1	—
Amortization of rate stabilization deferral	(8)	—	—	—	7	(15)	(10)	(5)	—
Amortization of debt fair value adjustment	(9)	(6)	—	—	—	(3)	—	—	—
Discrete impacts from EIMA and FEJA [c]	(51)	—	(51)	—	—	—	—	—	—
Amortization of debt costs	49	30	2	1	1	—	—	—	—
Provision for excess and obsolete inventory	51	49	1	—	—	1	—	—	—
Merger-related commitments[d]	—	—	—	—	—	(8)	(6)	(2)	—
Severance costs	25	17	—	—	—	3	—	—	—
Other	39	13	2	(2)	(7)	(6)	(2)	(3)	(2)
Total other non-cash operating activities	$415	$ 121	$ 58	$ 22	$ 35	$ 28	$ —	$ (3)	$ 7
Non-cash investing and financing activities:									
(Decrease) increase in capital expenditures not paid	$ (105)	$ 48	$ (82)	$ (44)	$ 6	$ (8)	$ —	$ 15	$ (14)
Fair value of pension obligation transferred in connection with the FitzPatrick acquisition	—	49	—	—	—	—	—	—	—
Change in PPE related to ARO update	103	103	—	—	—	—	—	—	—
Indemnification of like-kind exchange tax position[e]	—	—	23	—	—	—	—	—	—
Non-cash financing of capital projects	13	13	—	—	—	—	—	—	—
Dividends on stock compensation	3	—	—	—	—	—	—	—	—
Loss on reissuance of treasury stock	1,054	—	—	—	—	—	—	—	—

(a) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 15 — Asset Retirement Obligations of the Exelon 2017 Form 10-K for additional information regarding the accounting for nuclear decommissioning.
(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded in Operating revenues and expenses.
(c) Reflects the change in ComEd's distribution and energy efficiency formula rates. See Note 6 — Regulatory Matters for additional information.
(d) See Note 4 - Mergers, Acquisitions and Dispositions for additional information.
(e) See Note 12 - Income Taxes for discussion of the like-kind exchange tax position.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

The following tables provide a reconciliation of cash, cash equivalents and restricted cash reported within the Registrants' Consolidated Balance Sheets that sum to the total of the same amounts in their Consolidated Statements of Cash Flows.

June 30, 2018	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Cash and cash equivalents	$694	$ 420	$ 30	$ 18	$ 7	$195	$ 47	$141	$ 6
Restricted cash	206	130	5	5	1	38	33	—	5
Restricted cash included in other long-term assets	128	—	108	—	—	20	—	—	20
Total cash, cash equivalents and restricted cash	$1,028	$ 550	$ 143	$ 23	$ 8	$253	$ 80	$141	$ 31

December 31, 2017	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Cash and cash equivalents	$898	$ 416	$ 76	$ 271	$ 17	$30	$ 5	$ 2	$ 2
Restricted cash	207	138	5	4	1	42	35	—	6
Restricted cash included in other long-term assets	85	—	63	—	—	23	—	—	23
Total cash, cash equivalents and restricted cash	$1,190	$ 554	$ 144	$ 275	$ 18	$95	$ 40	$ 2	$ 31

June 30, 2017	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Cash and cash equivalents	$ 536	$ 265	$ 39	$ 45	$ 12	$151	$ 119	$ 6	$ 7
Restricted cash	252	166	12	4	6	40	34	—	7
Restricted cash included in other long-term assets	23	—	—	—	—	23	—	—	23
Total cash, cash equivalents and restricted cash	$ 811	$ 431	$ 51	$ 49	$ 18	$214	$ 153	$ 6	$ 37

December 31, 2016	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Cash and cash equivalents	$ 635	$ 290	$ 56	$ 63	$ 23	$170	$ 9	$ 46	$101
Restricted cash	253	158	2	4	24	43	33	—	9
Restricted cash included in other long-term assets	26	—	—	—	3	23	—	—	23
Total cash, cash equivalents and restricted cash	$ 914	$ 448	$ 58	$ 67	$ 50	$236	$ 42	$ 46	$133

For additional information on restricted cash see Note 1 — Significant Accounting Policies of the Exelon 2017 Form 10-K.

Supplemental Balance Sheet Information

The following tables provide additional information about assets and liabilities of the Registrants as of June 30, 2018 and December 31, 2017.

June 30, 2018	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Property, plant and equipment:									
Accumulated depreciation and amortization	$22,302 [(a)]	$ 12,143 [(a)]	$4,491	$3,482	$3,530	$671	$3,269	$1,295	$1,105
Accounts receivable:									
Allowance for uncollectible accounts	$339	$ 123	$82	$57	$21	$55	$23	$14	$18

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

December 31, 2017	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Property, plant and equipment:									
Accumulated depreciation and amortization	$21,064 (b)	$ 11,428 (b)	$4,269	$3,411	$3,405	$487	$3,177	$1,247	$1,066
Accounts receivable:									
Allowance for uncollectible accounts	$322	$ 114	$73	$56	$24	$55	$21	$16	$18

(a) Includes accumulated amortization of nuclear fuel in the reactor core of $3,094 million.
(b) Includes accumulated amortization of nuclear fuel in the reactor core of $3,159 million.

PECO Installment Plan Receivables (Exelon and PECO)

PECO enters into payment agreements with certain delinquent customers, primarily residential, seeking to restore their service, as required by the PAPUC. Customers with past due balances that meet certain income criteria are provided the option to enter into an installment payment plan, some of which have terms greater than one year. The receivable balance for these payment agreement receivables is recorded in accounts receivable for the current portion and other deferred debits and other assets for the noncurrent portion. The net receivable balance for installment plans with terms greater than one year was $11 million as of June 30, 2018 and December 31, 2017. The allowance for uncollectible accounts balance associated with these receivables at June 30, 2018 of $12 million consists of $4 million and $8 million for medium risk and high risk segments, respectively. The allowance for uncollectible accounts balance at December 31, 2017 of $11 million consists of $3 million and $8 million for medium risk and high risk segments, respectively. See Note 1 — Significant Accounting Policies of the Exelon 2017 Form 10-K for additional information regarding uncollectible accounts reserve methodology and assessment of the credit quality of the installment plan receivables.

19. Segment Information (All Registrants)

Operating segments for each of the Registrants are determined based on information used by the chief operating decision maker(s) (CODM) in deciding how to evaluate performance and allocate resources at each of the Registrants. Exelon has twelve reportable segments, which include ComEd, PECO, BGE, PHI's three reportable segments consisting of Pepco, DPL and ACE, and Generation’s six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and all other power regions referred to collectively as “Other Power Regions”, which includes activities in the South, West and Canada. ComEd, PECO, BGE, Pepco, DPL and ACE each represent a single reportable segment, and as such, no separate segment information is provided for these Registrants. Exelon, ComEd, PECO, BGE, Pepco, DPL and ACE's CODMs evaluate the performance of and allocate resources to ComEd, PECO, BGE, Pepco, DPL and ACE based on net income and return on equity.

The basis for Generation's reportable segments is the integrated management of its electricity business that is located in different geographic regions, and largely representative of the footprints of ISO/RTO and/or NERC regions, which utilize multiple supply sources to provide electricity through various distribution channels (wholesale and retail). Generation's hedging strategies and risk metrics are also aligned to these same geographic regions. Descriptions of each of Generation’s six reportable segments are as follows:

- Mid-Atlantic represents operations in the eastern half of PJM, which includes New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of Pennsylvania and North Carolina.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Pennsylvania, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the United States footprint of MISO, excluding MISO's Southern Region, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
- New York represents operations within ISO-NY, which covers the state of New York in its entirety.
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.
- Other Power Regions:
- South represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
- West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado and parts of New Mexico, Wyoming and South Dakota.
- Canada represents operations across the entire country of Canada and includes AESO, OIESO and the Canadian portion of MISO.

The CODMs for Exelon and Generation evaluate the performance of Generation's electric business activities and allocate resources based on revenues net of purchased power and fuel expense (RNF). Generation believes that RNF is a useful measurement of operational performance. RNF is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report. Generation's operating revenues include all sales to third parties and affiliated sales to the Utility Registrants. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for Generation's owned generation and fuel costs associated with tolling agreements. The results of Generation's other business activities are not regularly reviewed by the CODM and are therefore not classified as operating segments or included in the regional reportable segment amounts. These activities include natural gas, as well as other miscellaneous business activities that are not significant to Generation's overall operating revenues or results of operations. Further, Generation's unrealized mark-to-market gains and losses on economic hedging activities and its amortization of certain intangible assets and liabilities relating to commodity contracts recorded at fair value from mergers and acquisitions are also excluded from the regional reportable segment amounts. Exelon and Generation do not use a measure of total assets in making decisions regarding allocating resources to or assessing the performance of these reportable segments.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

An analysis and reconciliation of the Registrants' reportable segment information to the respective information in the consolidated financial statements for the three and six months ended June 30, 2018 and 2017 is as follows:
Three Months Ended June 30, 2018 and 2017

	Generation[(a)]	ComEd	PECO	BGE	PHI	Other[(b)]	Intersegment Eliminations	Exelon
Operating revenues[(c)]:								
2018								
Competitive businesses electric revenues	$ 3,939	$—	—	$—	$—	$—	$ (270)	$3,669
Competitive businesses natural gas revenues	489	—	—	—	—	—	—	489
Competitive businesses other revenues	151	—	—	—	—	—	(4)	147
Rate-regulated electric revenues	—	1,398	560	548	1,045	—	(9)	3,542
Rate-regulated natural gas revenues	—	—	93	114	28	—	(5)	230
Shared service and other revenues	—	—	—	—	3	487	(491)	(1)
Total operating revenues	$ 4,579	$1,398	$653	$662	$1,076	$487	$ (779)	$8,076
2017								
Competitive businesses electric revenues	$ 3,759	$—	$—	$—	$—	$—	$ (266)	$3,493
Competitive businesses natural gas revenues	430	—	—	—	—	—	—	430
Competitive businesses other revenues	27	—	—	—	—	—	—	27
Rate-regulated electric revenues	—	1,357	550	571	1,040	—	(7)	3,511
Rate-regulated natural gas revenues	—	—	80	103	22	—	(1)	204
Shared service and other revenues	—	—	—	—	12	449	(461)	—
Total operating revenues	$ 4,216	$1,357	$630	$674	$1,074	$449	$ (735)	$7,665
Intersegment revenues[(d)]:								
2018	$ 273	$5	$2	$6	$3	$487	$ (776)	$—
2017	266	3	2	3	12	448	(734)	—
Net income (loss):								
2018	$ 181	$164	$96	$51	$84	$(34)	$ —	$542
2017	(236)	118	88	45	66	13	—	94
Total assets:								
June 30, 2018	$ 47,668	$30,446	$10,345	$9,241	$21,766	$8,438	$ (10,655)	$117,249
December 31, 2017	48,457	29,726	10,170	9,104	21,247	8,618	(10,552)	116,770

176

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

(a) Generation includes the six reportable segments shown below: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions. Intersegment revenues for Generation for the three months ended June 30, 2018 include revenue from sales to PECO of $25 million, sales to BGE of $63 million, sales to Pepco of $46 million, sales to DPL of $30 million and sales to ACE of $6 million in the Mid-Atlantic region, and sales to ComEd of $103 million in the Midwest region, which eliminate upon consolidation. For the three months ended June 30, 2017, intersegment revenues for Generation include revenue from sales to PECO of $34 million, sales to BGE of $99 million, sales to Pepco of $68 million, sales to DPL of $40 million and sales to ACE of $7 million in the Mid-Atlantic region, and sales to ComEd of $18 million in the Midwest region, which eliminate upon consolidation.

(b) Other primarily includes Exelon’s corporate operations, shared service entities and other financing and investment activities.

(c) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in expenses on the Registrants’ Consolidated Statements of Operations and Comprehensive Income. See Note 18 — Supplemental Financial Information for total utility taxes for the three months ended June 30, 2018 and 2017.

(d) Intersegment revenues exclude sales to unconsolidated affiliates. The intersegment profit associated with Generation’s sale of certain products and services by and between Exelon’s segments is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. For Exelon, these amounts are included in Operating revenues in the Consolidated Statements of Operations and Comprehensive Income.

PHI:

	Pepco	DPL	ACE	Other[b]	Intersegment Eliminations	PHI
Operating revenues[a]:						
Three Months Ended June 30, 2018						
Rate-regulated electric revenues	$523	$261	$265	$—	$ (4)	$1,045
Rate-regulated natural gas revenues	—	28	—	—	—	28
Shared service and other revenues	—	—	—	108	(105)	3
Total operating revenues	$523	$289	$265	$108	$ (109)	$1,076
Three Months Ended June 30, 2017						
Rate-regulated electric revenues	$514	$260	$270	$—	$ (4)	$1,040
Rate-regulated natural gas revenues	—	22	—	—	—	22
Shared service and other revenues	—	—	—	13	(1)	12
Total operating revenues	$514	$282	$270	$13	$ (5)	$1,074
Intersegment revenues:						
Three Months Ended June 30, 2018	$2	$2	$1	$107	$ (109)	$3
Three Months Ended June 30, 2017	1	2	1	13	(5)	12
Net income (loss):						
Three Months Ended June 30, 2018	$54	$26	$8	$(7)	$ 3	$84
Three Months Ended June 30, 2017	43	19	8	(16)	12	66
Total assets:						
June 30, 2018	$8,123	$4,562	$3,619	$10,713	$ (5,251)	$21,766
December 31, 2017	7,832	4,357	3,445	10,600	(4,987)	21,247

(a)

Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in expenses on the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 18 — Supplemental Financial Information for total utility taxes for the three months ended June 30, 2018 and 2017.

(b) Other primarily includes PHI's corporate operations, shared service entities and other financing and investment activities.

The following tables disaggregate the Registrants' revenue recognized from contracts with customers into categories that depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors for three months ended June 30, 2018 and 2017. For Generation, the disaggregation of revenues reflects Generation's two primary products of power sales and natural gas sales, with further disaggregation of power sales provided by geographic region. For the Utility Registrants, the disaggregation of revenues reflects the two primary utility services of rate-regulated electric sales and rate-regulated natural gas sales (where applicable), with further disaggregation of these tariff sales provided by major customer groups. Exelon's disaggregated revenues are consistent with Generation and the Utility Registrants, but exclude any intercompany revenues.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Competitive Business Revenues (Generation):

	Three Months Ended June 30, 2018				
	Revenues from external parties[a]				
	Contracts with customers	Other[b]	Total	Intersegment revenues	Total Revenues
Mid-Atlantic	$1,220	$ 58	$1,278	$ 4	$ 1,282
Midwest	1,062	73	1,135	(5)	1,130
New England	551	(14)	537	(3)	534
New York	392	(2)	390	2	392
ERCOT	165	111	276	1	277
Other Power Regions	210	113	323	(36)	287
Total Competitive Businesses Electric Revenues	3,600	339	3,939	(37)	3,902
Competitive Businesses Natural Gas Revenues	295	194	489	37	526
Competitive Businesses Other Revenues[c]	125	26	151	—	151
Total Generation Consolidated Operating Revenues	$4,020	$ 559	$4,579	$ —	$ 4,579

	Three Months Ended June 30, 2017				
	Revenues from external customers[a]				
	Contracts with customers	Other[b]	Total	Intersegment revenues	Total Revenues
Mid-Atlantic	$1,368	$ (12)	$1,356	$ 9	$ 1,365
Midwest	986	72	1,058	(8)	1,050
New England	462	(24)	438	(5)	433
New York	405	(13)	392	(5)	387
ERCOT	186	61	247	—	247
Other Power Regions	142	126	268	(9)	259
Total Competitive Businesses Electric Revenues	3,549	210	3,759	(18)	3,741
Competitive Businesses Natural Gas Revenues	244	186	430	19	449
Competitive Businesses Other Revenues[c]	179	(152)	27	(1)	26
Total Generation Consolidated Operating Revenues	$3,972	$ 244	$4,216	$ —	$ 4,216

(a) Includes all wholesale and retail electric sales to third parties and affiliated sales to the Utility Registrants.
(b) Includes revenues from derivatives and leases.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Includes a $15 million decrease to revenues for the amortization of intangible assets and liabilities related to commodity contracts recorded at fair value for the three months ended June 30, 2017, unrealized mark-to-market losses of $5 million and $143 million for the three months ended June 30, 2018 and 2017, respectively, and elimination of intersegment revenues.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Revenues net of purchased power and fuel expense (Generation):

	Three Months Ended June 30, 2018			Three Months Ended June 30, 2017		
	RNF from external customers[a]	Intersegment RNF	Total RNF	RNF from external customers[a]	Intersegment RNF	Total RNF
Mid-Atlantic	$722	$ 13	$735	$757	$ 26	$783
Midwest	770	2	772	728	—	728
New England	104	(8)	96	157	(10)	147
New York	259	7	266	270	—	270
ERCOT	129	(47)	82	121	(51)	70
Other Power Regions	125	(35)	90	134	(44)	90
Total Revenues net of purchased power and fuel for Reportable Segments	2,109	(68)	2,041	2,167	(79)	2,088
Other[b]	190	68	258	(108)	79	(29)
Total Generation Revenues net of purchased power and fuel expense	$2,299	$ —	$2,299	$2,059	$ —	$2,059

(a) Includes purchases and sales from/to third parties and affiliated sales to the Utility Registrants.

(b) Other represents activities not allocated to a region. See text above for a description of included activities. Includes a $20 million decrease to RNF for the amortization of intangible assets and liabilities related to commodity contracts for the three months ended June 30, 2017, unrealized mark-to-market gains of $90 million and losses of $184 million for the three months ended June 30, 2018 and 2017, respectively, accelerated nuclear fuel amortization associated with announced early plant retirements as discussed in Note 8 - Early Plant Retirements of $20 million decrease and $2 million decrease to revenue net of purchased power and fuel expense for the three months ended June 30, 2018, and 2017, respectively, and the elimination of intersegment revenue net of purchased power and fuel expense.

179

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Electric and Gas Revenue by Customer Class (ComEd, PECO, BGE, PHI, PECO, DPL and ACE):

	Three Months Ended June 30, 2018						
Revenues from contracts with customers	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Rate-regulated electric revenues							
Residential	$699	$ 338	$295	$505	$228	$142	$135
Small commercial & industrial	357	97	60	115	33	44	38
Large commercial & industrial	127	52	101	282	212	25	45
Public authorities & electric railroads	12	6	7	16	9	3	4
Other[(a)]	213	60	78	133	49	41	44
Total rate-regulated electric revenues[(b)]	1,408	553	541	1,051	531	255	266
Rate-regulated natural gas revenues							
Residential	—	62	74	13	—	13	—
Small commercial & industrial	—	25	13	8	—	8	—
Large commercial & industrial	—	—	23	1	—	1	—
Transportation	—	5	—	4	—	4	—
Other[(c)]	—	1	12	2	—	2	—
Total rate-regulated natural gas revenues[(d)]	—	93	122	28	—	28	—
Total rate-regulated revenues from contracts with customers	1,408	646	663	1,079	531	283	266
Other revenues							
Revenues from alternative revenue programs	(17)	2	(4)	(7)	(10)	4	(1)
Other rate-regulated electric revenues[(e)]	7	5	3	4	2	2	—
Other rate-regulated natural gas revenues[(e)]	—	—	—	—	—	—	—
Total other revenues	(10)	7	(1)	(3)	(8)	6	(1)
Total rate-regulated revenues for reportable segments	$1,398	$ 653	$662	$1,076	$523	$289	$265

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	Three Months Ended June 30, 2017						
Revenues from contracts with customers	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Rate-regulated electric revenues							
Residential	$644	$ 331	$300	$498	$ 223	$145	$130
Small commercial & industrial	340	100	58	119	34	45	40
Large commercial & industrial	119	57	107	268	193	26	49
Public authorities & electric railroads	11	8	8	16	8	4	4
Other[(a)]	217	51	71	129	49	39	44
Total rate-regulated electric revenues[(b)]	1,331	547	544	1,030	507	259	267
Rate-regulated natural gas revenues							
Residential	—	50	60	10	—	10	—
Small commercial & industrial	—	22	12	5	—	5	—
Large commercial & industrial	—	—	19	2	—	2	—
Transportation	—	5	—	2	—	2	—
Other[(c)]	—	3	4	3	—	3	—
Total rate-regulated natural gas revenues[(d)]	—	80	95	22	—	22	—
Total rate-regulated revenues from contracts with customers	1,331	627	639	1,052	507	281	267
Other revenues							
Revenues from alternative revenue programs	18	—	32	8	5	—	3
Other rate-regulated electric revenues[(e)]	8	3	2	3	2	1	—
Other rate-regulated natural gas revenues[(e)]	—	—	1	—	—	—	—
Other revenues[(f)]	—	—	—	11	—	—	—
Total other revenues	26	3	35	22	7	1	3
Total rate-regulated revenues for reportable segments	$1,357	$ 630	$674	$1,074	$ 514	$282	$270

(a) Includes revenues from transmission revenue from PJM, wholesale electric revenue and mutual assistance revenue.

(b) Includes operating revenues from affiliates of $5 million, $2 million, $2 million, $3 million, $2 million, $2 million and $1 million at ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively, for the three months ended June 30, 2018 and $3 million, $2 million, $1 million, $1 million $1 million, $2 million and $1 million at ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively, for the three months ended June 30, 2017.

(c) Includes revenues from off-system natural gas sales.

(d) Includes operating revenues from affiliates of less than $1 million and $4 million at PECO and BGE, respectively, for the three months ended June 30, 2018 and less than $1 million and $2 million at PECO and BGE, respectively, for the three months ended June 30, 2017.

(e) Includes late payment charge revenues.

(f) Includes operating revenues from affiliates of $11 million at PHI for the three months ended June 30, 2017.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Six Months Ended June 30, 2018 and 2017

	Generation[(a)]	ComEd	PECO	BGE	PHI	Other[(b)]	Intersegment Eliminations	Exelon
Operating revenues[(c)]:								
2018								
Competitive businesses electric revenues	$ 8,448	$—	$—	$—	$—	$ —	$ (663)	$7,785
Competitive businesses natural gas revenues	1,444	—	—	—	—	—	(8)	1,436
Competitive businesses other revenues	198	—	—	—	—	—	(2)	196
Rate-regulated electric revenues	—	2,910	1,193	1,206	2,214	—	(27)	7,496
Rate-regulated natural gas revenues	—	—	325	433	106	—	(9)	855
Shared service and other revenues	—	—	—	—	7	940	(946)	1
Total operating revenues	$ 10,090	$2,910	$1,518	$1,639	$2,327	$ 940	$ (1,655)	$17,769
2017								
Competitive businesses electric revenues	$ 7,467	$—	$—	$—	$—	$ —	$ (592)	$6,875
Competitive businesses natural gas revenues	1,348	—	—	—	—	—	—	1,348
Competitive businesses other revenues	278	—	—	—	—	—	(1)	277
Rate-regulated electric revenues	—	2,656	1,140	1,237	2,138	1	(16)	7,156
Rate-regulated natural gas revenues	—	—	286	388	87	—	(4)	757
Shared service and other revenues	—	—	—	—	23	870	(893)	—
Total operating revenues	$ 9,093	$2,656	$1,426	$1,625	$2,248	$ 871	$ (1,506)	$16,413
Intersegment revenues[(d)]:								
2018	$ 672	$19	$3	$12	$7	$ 937	$ (1,650)	$—
2017	594	9	3	8	23	866	(1,503)	—
Net income (loss):								
2018	$ 368	$329	$210	$179	$149	$ (56)	$ —	$1,179
2017	164	259	215	169	205	54	—	1,066

182

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

(a) Generation includes the six reportable segments shown below: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions. Intersegment revenues for Generation for the six months ended June 30, 2018 include revenue from sales to PECO of $61 million, sales to BGE of $128 million, sales to Pepco of $98 million, sales to DPL of $76 million and sales to ACE of $12 million in the Mid-Atlantic region, and sales to ComEd of $297 million in the Midwest region, which eliminate upon consolidation. For the six months ended June 30, 2017, intersegment revenues for Generation include revenue from sales to PECO of $79 million, sales to BGE of $233 million, sales to Pepco of $152 million, sales to DPL of $91 million and sales to ACE of $16 million in the Mid-Atlantic region, and sales to ComEd of $23 million in the Midwest region, which eliminate upon consolidation.

(b) Other primarily includes Exelon’s corporate operations, shared service entities and other financing and investment activities.

(c) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in expenses on the Registrants’ Consolidated Statements of Operations and Comprehensive Income. See Note 18 — Supplemental Financial Information for total utility taxes for the six months ended June 30, 2018 and 2017.

(d) Intersegment revenues exclude sales to unconsolidated affiliates. The intersegment profit associated with Generation’s sale of certain products and services by and between Exelon’s segments is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. For Exelon, these amounts are included in Operating revenues in the Consolidated Statements of Operations and Comprehensive Income.

PHI:

	Pepco	DPL	ACE	Other[b]	Intersegment Eliminations	PHI
Operating revenues[a]:						
Six Months Ended June 30, 2018						
Rate-regulated electric revenues	$1,080	$567	$575	$—	$ (8)	$2,214
Rate-regulated natural gas revenues	—	106	—	—	—	106
Shared service and other revenues	—	—	—	221	(214)	7
Total operating revenues	$1,080	$673	$575	$ 221	$ (222)	$2,327
Six Months Ended June 30, 2017						
Rate-regulated electric revenues	$1,045	$557	$544	$ 1	$ (9)	$2,138
Rate-regulated natural gas revenues	—	87	—	—	—	87
Shared service and other revenues	—	—	—	25	(2)	23
Total operating revenues	$1,045	$644	$544	$ 26	$ (11)	$2,248
Intersegment revenues:						
Six Months Ended June 30, 2018	$3	$4	$2	$ 220	$ (222)	$7
Six Months Ended June 30, 2017	3	4	1	24	(9)	23
Net income (loss):						
Six Months Ended June 30, 2018	$85	$57	$15	$ (15)	$ 7	$149
Six Months Ended June 30, 2017	101	76	36	(31)	23	205

(a) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in expenses on the Registrants’ Consolidated Statements of Operations and Comprehensive Income. See Note 18 — Supplemental Financial Information for total utility taxes for the six months ended June 30, 2018 and 2017.

(b) Other primarily includes PHI’s corporate operations, shared service entities and other financing and investment activities.

The following tables disaggregate the Registrants' revenue recognized from contracts with customers into categories that depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors for six months ended June 30, 2018 and 2017. For Generation, the disaggregation of revenues reflects Generation’s two primary products of power sales and natural gas sales, with further disaggregation of power sales provided by geographic region. For the Utility Registrants, the disaggregation of revenues reflects the two primary utility services of rate-regulated electric sales and rate-regulated natural gas sales (where applicable), with further disaggregation of these tariff sales provided by major customer groups. Exelon’s disaggregated revenues are consistent with Generation and the Utility Registrants but exclude any intercompany revenues.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Competitive Business Revenues (Generation):

	Six Months Ended June 30, 2018 Revenues from external parties[(a)] Contracts with customers	Other[(b)]	Total	Intersegment Revenues	Total Revenues
Mid-Atlantic	$2,574	$138	$2,712	$ 10	$ 2,722
Midwest	2,336	143	2,479	(4)	2,475
New England	1,276	54	1,330	(4)	1,326
New York	831	(31)	800	1	801
ERCOT	315	169	484	2	486
Other Power Regions	420	223	643	(67)	576
Total Competitive Businesses Electric Revenues	7,752	696	8,448	(62)	8,386
Competitive Businesses Natural Gas Revenues	816	628	1,444	62	1,506
Competitive Businesses Other Revenues[(c)]	258	(60)	198	—	198
Total Generation Consolidated Operating Revenues	$8,826	$1,264	$10,090	$ —	$ 10,090

	Six Months Ended June 30, 2017 Revenues from external customers[(a)] Contracts with customers	Other[(b)]	Total	Intersegment revenues	Total Revenues
Mid-Atlantic	$2,862	$ (77)	$2,785	$ 5	$ 2,790
Midwest	1,964	143	2,107	(5)	2,102
New England	1,051	(64)	987	(7)	980
New York	708	(16)	692	(8)	684
ERCOT	354	85	439	(1)	438
Other Power Regions	270	187	457	(14)	443
Total Competitive Businesses Electric Revenues	7,209	258	7,467	(30)	7,437
Competitive Businesses Natural Gas Revenues	1,012	336	1,348	31	1,379
Competitive Businesses Other Revenues[(c)]	386	(108)	278	(1)	277
Total Generation Consolidated Operating Revenues	$8,607	$ 486	$9,093	$ —	$ 9,093

(a) Includes all wholesale and retail electric sales to third parties and affiliated sales to the Utility Registrants.
(b) Includes revenues from derivatives and leases.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Includes a $17 million decrease to revenues for the amortization of intangible assets and liabilities related to commodity contracts recorded at fair value for the six months ended June 30, 2017, unrealized mark-to-market losses of $102 million and $98 million for the six months ended June 30, 2018 and 2017, respectively, and elimination of intersegment revenues.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Revenues net of purchased power and fuel expense (Generation):

	Six Months Ended June 30, 2018			Six Months Ended June 30, 2017		
	RNF from external customers[a]	Intersegment RNF	Total RNF	RNF from external customers[a]	Intersegment RNF	Total RNF
Mid-Atlantic	$1,558	$ 28	$1,586	$1,513	$ 44	$1,557
Midwest	1,617	14	1,631	1,431	12	1,443
New England	227	(11)	216	271	(14)	257
New York	541	8	549	415	—	415
ERCOT	235	(117)	118	214	(76)	138
Other Power Regions	284	(76)	208	240	(88)	152
Total Revenues net of purchased power and fuel expense for Reportable Segments	4,462	(154)	4,308	4,084	(122)	3,962
Other[b]	55	154	209	54	122	176
Total Generation Revenues net of purchased power and fuel expense	$4,517	$ —	$4,517	$4,138	$ —	$4,138

(a) Includes purchases and sales from/to third parties and affiliated sales to the Utility Registrants.

(b) Other represents activities not allocated to a region. See text above for a description of included activities. Includes a $22 million decrease to RNF for the amortization of intangible assets and liabilities related to commodity contracts for the six months ended June 30, 2017, unrealized mark-to-market losses of $175 million and $233 million for the six months ended June 30, 2018 and 2017, respectively, accelerated nuclear fuel amortization associated with announced early plant retirements as discussed in Note 8 - Early Plant Retirements of $34 million decrease to revenue net of purchased power and fuel expense for the six months ended June 30, 2018, and the elimination of intersegment revenue net of purchased power and fuel expense.

185

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Electric and Gas Revenue by Customer Class (ComEd, PECO, BGE, PHI, PECO, DPL and ACE):

	Six Months Ended June 30, 2018						
Revenues from contracts with customers	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Rate-regulated electric revenues							
Residential	$1,416	$741	$688	$1,114	$486	$333	$295
Small commercial & industrial	741	198	128	230	65	90	75
Large commercial & industrial	280	110	207	541	402	48	91
Public authorities & electric railroads	25	14	14	30	16	7	7
Other[(a)]	444	122	156	289	98	82	110
Total rate-regulated electric revenues[(b)]	2,906	1,185	1,193	2,204	1,067	560	578
Rate-regulated natural gas revenues							
Residential	—	223	298	60	—	60	—
Small commercial & industrial	—	87	47	26	—	26	—
Large commercial & industrial	—	1	70	5	—	5	—
Transportation	—	11	—	9	—	9	—
Other[(c)]	—	3	40	6	—	6	—
Total rate-regulated natural gas revenues[(d)]	—	325	455	106	—	106	—
Total rate-regulated revenues from contracts with customers	2,906	1,510	1,648	2,310	1,067	666	578
Other revenues							
Revenues from alternative revenue programs	(12)	1	(17)	12	10	5	(3)
Other rate-regulated electric revenues[(e)]	16	7	6	5	3	2	—
Other rate-regulated natural gas revenues[(e)]	—	—	2	—	—	—	—
Total other revenues	4	8	(9)	17	13	7	(3)
Total rate-regulated revenues for reportable segments	$2,910	$1,518	$1,639	$2,327	$1,080	$673	$575

186

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	Six Months Ended June 30, 2017						
Revenues from contracts with customers	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Rate-regulated electric revenues							
Residential	$1,255	$713	$686	$1,053	$460	$321	$272
Small commercial & industrial	668	197	128	233	68	89	76
Large commercial & industrial	226	109	215	526	382	50	94
Public authorities & electric railroads	22	16	15	31	16	8	7
Other[(a)]	437	99	138	253	96	78	86
Total rate-regulated electric revenues[(b)]	2,608	1,134	1,182	2,096	1,022	546	535
Rate-regulated natural gas revenues							
Residential	—	192	245	50	—	50	—
Small commercial & industrial	—	77	42	22	—	22	—
Large commercial & industrial	—	—	64	4	—	4	—
Transportation	—	11	—	7	—	7	—
Other[(c)]	—	6	17	4	—	4	—
Total rate-regulated natural gas revenues[(d)]	—	286	368	87	—	87	—
Total rate-regulated revenues from contracts with customers	2,608	1,420	1,550	2,183	1,022	633	535
Other revenues							
Revenues from alternative revenue programs	32	—	66	38	20	9	9
Other rate-regulated electric revenues[(e)]	16	6	7	5	3	2	—
Other rate-regulated natural gas revenues[(e)]	—	—	2	—	—	—	—
Other revenues[(f)]	—	—	—	22	—	—	—
Total other revenues	48	6	75	65	23	11	9
Total rate-regulated revenues for reportable segments	$2,656	$1,426	$1,625	$2,248	$1,045	$644	$544

(a) Includes revenues from transmission revenue from PJM, wholesale electric revenue and mutual assistance revenue.

(b) Includes operating revenues from affiliates of $19 million, $3 million, $3 million, $7 million, $3 million, $4 million and $2 million at ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively, for the six months ended June 30, 2018 and $9 million, $3 million, $3 million, $1 million, $3 million, $4 million and $1 million at ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively, for the six months ended June 30, 2017.

(c) Includes revenues from off-system natural gas sales.

(d) Includes operating revenues from affiliates of less than $1 million and $9 million at PECO and BGE, respectively, for the six months ended June 30, 2018 and less than $1 million and $5 million at PECO and BGE, respectively, for the six months ended June 30, 2017.

(e) Includes late payment charge revenues.

(f) Includes operating revenues from affiliates of $22 million at PHI for the six months ended June 30, 2017.

20. Subsequent Events (Exelon and Generation)

Acquisition of FirstEnergy Solutions Load Business

On July 9, 2018, Generation entered into an Asset Purchase Agreement (the Purchase Agreement) with FirstEnergy Solutions Corporation (FirstEnergy). Pursuant to the Purchase Agreement, FirstEnergy assigns all of its retail electricity and wholesale load serving contracts and certain other related commodity contracts to Generation for an all cash purchase price of $140 million. Pursuant to the Purchase Agreement, Generation has agreed to use its commercially reasonable efforts to replace the guarantees and other credit support currently being provided by FirstEnergy in support of the ongoing competitive retail businesses and to reimburse FirstEnergy for any payments arising pursuant to such arrangements continuing for any post-closing period.

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 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. The Purchase Agreement also includes various representations, warranties, covenants, indemnification and other provisions customary for a transaction of this nature.

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 the Oyster Creek Generating Station (Oyster Creek) located in Forked River, New Jersey. In February 2018, Generation announced that Oyster Creek would permanently shut down by October 2018, at the end of its current operating cycle. Generation is required to close Oyster Creek by December 2019, as part of an agreement with the State of New Jersey. Under the terms of the transaction, Generation will transfer to OCEP substantially all the assets associated with Oyster Creek, including assets held in 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. The terms of the transaction also include various forms of performance assurance for the obligations of OCEP to timely complete the required decommissioning, including a parental guaranty from Holtec for all performance and payment obligations of OCEP, and a requirement for Holtec to deliver a letter of credit to Generation upon the occurrence of specified events.

As a result of the transaction, in the third quarter of 2018, Exelon and Generation will reclassify certain Oyster Creek assets and liabilities on Exelon’s and Generation’s Consolidated Balance Sheets as held for sale at their respective fair values. Exelon and Generation estimate a pre-tax charge to operating and maintenance expense ranging from $60 million to $100 million will be recognized in the third quarter of 2018 upon remeasurement of the Oyster Creek ARO. 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

Table of Contents

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.

Table of Contents

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations
(Dollars in millions except per share data, unless otherwise noted)
Exelon
Executive Overview
Exelon, a utility services holding company, operates through the following principal subsidiaries:

- Generation, whose integrated business consists of the generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity and natural gas to both wholesale and retail customers. Generation also sells renewable energy and other energy-related products and services.
- ComEd, whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services in northern Illinois, including the City of Chicago.
- PECO, whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision distribution services in the Pennsylvania counties surrounding the City of Philadelphia.
- BGE, whose business consists of the purchase and regulated retail sale of electricity and natural gas and the provision of electricity distribution and transmission and gas distribution services in central Maryland, including the City of Baltimore.
- Pepco, whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission in the District of Columbia and major portions of Prince George's County and Montgomery County in Maryland.
- DPL, whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services in portions of Maryland and Delaware, and the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services in northern Delaware.
- ACE, whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services in southern New Jersey.

Pepco, DPL and ACE are operating companies of PHI, which is a utility services holding company and a wholly owned subsidiary of Exelon.
Exelon has twelve reportable segments consisting of Generation's six reportable segments (Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions in Generation), ComEd, PECO, BGE and PHI's three utility reportable segments (Pepco, DPL and ACE). See Note 19 — Segment Information of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's reportable segments.
Through its business services subsidiary BSC, Exelon provides its operating subsidiaries with a variety of corporate governance support services including corporate strategy and development, legal, human resources, information technology, finance, real estate, security, corporate communications and

Table of Contents

supply at cost. The costs of these services are directly charged or allocated to the applicable operating segments. The services are provided pursuant to service agreements. Additionally, the results of Exelon's corporate operations include interest costs income from various investment and financing activities.

PHISCO, a wholly owned subsidiary of PHI, provides a variety of support services at cost, including legal, accounting, engineering, distribution and transmission planning, asset management, system operations and power procurement, to PHI and its operating subsidiaries. These services are directly charged or allocated pursuant to service agreements among PHISCO and the participating operating subsidiaries.

Exelon's consolidated financial information includes the results of its eight separate operating subsidiary registrants, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, which, along with Exelon, are collectively referred to as the Registrants. The following combined Management's Discussion and Analysis of Financial Condition and Results of Operations is separately filed by Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE. However, none of the Registrants makes any representation as to information related solely to any of the other Registrants.

Table of Contents

Financial Results of Operations
GAAP Results of Operations
The following tables set forth Exelon's GAAP consolidated results of operations for the three and six months ended June 30, 2018 compared to the same period in 2017. All amounts presented below are before the impact of income taxes, except as noted.

	Three Months Ended June 30, 2018							2017	Favorable (Unfavorable)
	Generation	ComEd	PECO	BGE	PHI	Other	Exelon	Exelon	Variance
Operating revenues	$4,579	$1,398	$653	$662	$1,076	$(292)	$8,076	$7,665	$ 411
Purchased power and fuel	2,280	477	222	229	381	(274)	3,315	3,086	(229)
Revenue net of purchased power and fuel[(a)]	2,299	921	431	433	695	(18)	4,761	4,579	182
Other operating expenses									
Operating and maintenance	1,418	324	191	176	255	(57)	2,307	2,945	638
Depreciation and amortization	466	231	74	114	180	23	1,088	915	(173)
Taxes other than income	134	79	39	59	107	10	428	420	(8)
Total other operating expenses	2,018	634	304	349	542	(24)	3,823	4,280	457
Gain on sales of assets and businesses	1	1	—	1	—	1	4	1	3
Operating income	282	288	127	85	153	7	942	300	642
Other income and (deductions)									
Interest expense, net	(102)	(85)	(32)	(25)	(65)	(64)	(373)	(436)	63
Other, net	29	4	—	4	11	(4)	44	177	(133)
Total other income and (deductions)	(73)	(81)	(32)	(21)	(54)	(68)	(329)	(259)	(70)
Income (loss) before income taxes	209	207	95	64	99	(61)	613	41	572
Income taxes	23	43	(1)	13	15	(27)	66	(62)	(128)
Equity in losses of unconsolidated affiliates	(5)	—	—	—	—	—	(5)	(9)	4
Net income (loss)	181	164	96	51	84	(34)	542	94	448
Net income (loss) attributable to noncontrolling interests	3	—	—	—	—	—	3	(1)	(4)
Net income (loss) attributable to common shareholders	$178	$164	$96	$51	$84	$(34)	$539	$95	$ 444

192

Table of Contents

	Six Months Ended June 30, 2018							2017	Favorable (Unfavorable)
	Generation	ComEd	PECO	BGE	PHI	Other	Exelon	Exelon	Variance
Operating revenues	$10,090	$2,910	$1,518	$1,639	$2,327	$(715)	$17,769	$16,413	$ 1,356
Purchased power and fuel expense	5,573	1,082	555	609	901	(678)	8,042	6,985	(1,057)
Revenue net of purchased power and fuel expense[(a)]	4,517	1,828	963	1,030	1,426	(37)	9,727	9,428	299
Other operating expenses									
Operating and maintenance	2,756	638	466	397	563	(129)	4,691	5,383	692
Depreciation and amortization	914	459	149	248	363	46	2,179	1,811	(368)
Taxes other than income	272	156	79	124	221	22	874	857	(17)
Total other operating expenses	3,942	1,253	694	769	1,147	(61)	7,744	8,051	307
Gain on sales of assets and businesses	54	5	—	1	—	—	60	5	55
Bargain purchase gain	—	—	—	—	—	—	—	226	(226)
Operating income	629	580	269	262	279	24	2,043	1,608	435
Other income and (deductions)									
Interest expense, net	(202)	(175)	(64)	(51)	(128)	(125)	(745)	(809)	64
Other, net	(15)	12	2	9	22	(13)	17	434	(417)
Total other income and (deductions)	(217)	(163)	(62)	(42)	(106)	(138)	(728)	(375)	(353)
Income (loss) before income taxes	412	417	207	220	173	(114)	1,315	1,233	82
Income taxes	32	88	(3)	41	24	(57)	125	149	24
Equity in (losses) earnings of unconsolidated affiliates	(12)	—	—	—	—	1	(11)	(18)	7
Net income (loss)	368	329	210	179	149	(56)	1,179	1,066	113
Net income (loss) attributable to noncontrolling interests	54	—	—	—	—	—	54	(20)	(74)
Net income (loss) attributable to common shareholders	$314	$329	$210	$179	$149	$(56)	$1,125	$1,086	$ 39

(a) The Registrants evaluate operating performance using the measure of revenues net of purchased power and fuel expense. The Registrants believe that revenues net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate their operational performance. Revenues net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Three Months Ended June 30, 2018 Compared to Three Months Ended June 30, 2017. Exelon's Net income attributable to common shareholders was $539 million for the three months ended June 30, 2018 as compared to $95 million for the three months ended June 30, 2017, and diluted earnings per average common share were $0.56 for the three months ended June 30, 2018 as compared to $0.10 for the three months ended June 30, 2017.

Table of Contents

Revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $182 million for the three months ended June 30, 2018 compared to the same period in 2017 primarily due to the following factors:

- Increase of $274 million at Generation due to mark-to-market gains of $90 million in 2018 compared to mark-to-market losses of $184 million in 2017;
- Decrease of $34 million at Generation primarily due to lower realized energy prices partially offset by increased capacity prices, decreased nuclear outage days, the impact of Illinois ZES and impacts of Generation's natural gas portfolio;
- Decrease of $37 million at ComEd primarily due to lower revenues resulting from the change to defer and recover over time energy efficiency costs pursuant to FEJA; and
- Decrease of $70 million in electric and gas revenues across all Utility Registrants, primarily reflecting lower revenues resulting from the anticipated pass back of TCJA tax savings through customer rates, partially offset by higher utility revenues due to regulatory rate increases at ComEd and PHI.

Operating and maintenance expense decreased by $638 million for the three months ended June 30, 2018 as compared to the same period in 2017 primarily due to the following factors:

- Decrease of $379 million at Generation due to long-lived asset impairments primarily related to the EGTP assets held for sale in 2017, offset by long-lived asset impairments of certain merchant wind assets in West Texas in 2018;
- Decrease of $69 million due to one-time charges related to Generation's decision to early retire the TMI nuclear facility in 2017;
- Decrease of $64 million at Generation due to lower nuclear refueling outage costs;
- Decrease of $60 million at Generation in labor, contracting and materials expense due to decreased spending related to energy efficiency projects and decreased costs related to the sale of Generation's electrical contracting business; and
- Decrease of $37 million at ComEd primarily due to the change to defer and recover over time energy efficiency costs pursuant to FEJA.

Depreciation and amortization expense increased by $173 million for the three months ended June 30, 2018 as compared to the same period in 2017 primarily as a result of ongoing capital expenditures across all operating companies, accelerated depreciation and amortization due to Generation's decision to early retire the Oyster Creek and TMI nuclear facilities, increased amortization of Pepco's DC PLUG regulatory asset (an equal and offsetting amount has been reflected in Operating revenues), partially offset by certain regulatory assets that became fully amortized as of December 31, 2017 for BGE.

Taxes other than income remained relatively consistent for the three months ended June 30, 2018 compared to the same period in 2017.

Gain on sales of assets and businesses increased by $3 million for the three months ended June 30, 2018 compared to the same period in 2017 primarily due to a true up related to Generation's first quarter 2018 sale of its electrical contracting business.

Interest expense, net decreased by $63 million due to the retirement of long-term debt.

Table of Contents

Other, net decreased by $133 million primarily due to net unrealized and realized losses on NDT funds at Generation for the three months ended June 30, 2018 compared to net unrealized and realized gains on NDT funds for the same period in 2017.

Exelon's effective income tax rates for the three months ended June 30, 2018 and 2017 were 10.8% and (151.2)%, respectively. The increase in the effective income tax rate for the three months ended June 30, 2018 compared to the same period in 2017 is primarily related to tax savings due to the lower federal income tax rate as a result of the TCJA at all Registrants, which is offset in Operating revenues at the Utility Registrants for the anticipated pass back of the tax savings through customer rates. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates. See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on TCJA's impact on regulatory proceedings.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017. Exelon's Net income attributable to common shareholders was $1,125 million for the six months ended June 30, 2018 compared to $1,086 million for the six months ended June 30, 2017, and diluted earnings per average common share were $1.16 for the six months ended June 30, 2018 compared to $1.17 for the six months ended June 30, 2017.

Revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $299 million for the six months ended June 30, 2018 as compared to the same period in 2017. The year-over-year increase in Revenue net of purchased power and fuel expense was primarily due to the following factors:

- Increase of $321 million at Generation primarily due to impact of the New York CES and Illinois ZES (including the impact of zero emission credits generated in Illinois from June 1, 2017 through December 31, 2017), increased capacity prices, the acquisition of the FitzPatrick nuclear facility and decreased nuclear outage days, impacts of Generation's natural gas portfolio and the addition of two combined-cycle gas turbines in Texas, partially offset by the impact of the deconsolidation of EGTP in 2017, the conclusion of the Ginna Reliability Support Services Agreement and lower realized energy prices;
- Increase of $58 million at Generation due to mark-to-market losses of $175 million in 2018 compared to $233 million in 2017;
- Increase of $52 million at PECO, DPL and ACE primarily due to favorable weather conditions within their respective service territories;
- Increase of $47 million due to higher mutual assistance revenues across all Utility Registrants, primarily at ComEd;
- Decrease of $94 million at ComEd primarily due to lower revenues resulting from the change to defer and recover over time energy efficiency costs pursuant to FEJA; and
- Decrease of $156 million in electric and gas revenues across all Utility Registrants, primarily reflecting lower revenues resulting from the anticipated pass back of TCJA tax savings through customer rates, partially offset by higher utility revenues due to regulatory rate increases at ComEd, BGE and PHI.

Table of Contents

Operating and maintenance expense decreased by $692 million for the six months ended June 30, 2018 compared to the same period in 2017 primarily due to the following factors:

- Decrease of $378 million at Generation due to long-lived asset impairments primarily related to the EGTP assets held for sale in 2017, offset by long-lived asset impairments of certain merchant wind assets in West Texas in 2018;
- Decrease of $96 million at Generation due to lower nuclear refueling outage costs;
- Decrease of $94 million at ComEd primarily due to the change to defer and recover over time energy efficiency costs pursuant to FEJA;
- Decrease of $55 million at Generation due to lower merger-related costs;
- Decrease of $42 million due to one-time charges related to Generation's decision to early retire the TMI nuclear facility in 2017, partially offset by one-time charges due to Generation's decision to early retire the Oyster Creek nuclear facility in 2018;
- Decrease of $36 million related to a supplemental NEIL insurance distribution at Generation;
- Increase of $81 million at PECO and BGE due to increased storm costs; and
- Increase of $47 million due to higher mutual assistance expenses across all Utility Registrants, primarily at ComEd.

Depreciation and amortization expense increased by $368 million for the six months ended June 30, 2018 compared to the same period in 2017 primarily due to increased depreciation expense as a result of ongoing capital expenditures across all operating companies, accelerated depreciation and amortization due to Generation's decision to early retire the Oyster Creek and TMI nuclear facilities, increased amortization of Pepco's DC PLUG regulatory asset (an equal and offsetting amount has been reflected in Operating revenues), partially offset by certain regulatory assets that became fully amortized as of December 31, 2017 for BGE.

Taxes other than income increased due to increased gross receipts tax accruals at PECO and Pepco for the six months ended June 30, 2018 compared to the same period in 2017.

Gain on sales of assets and businesses increased by $55 million for the six months ended June 30, 2018 compared to the same period in 2017 primarily due to Generation's sale of its electrical contracting business.

Bargain purchase gain decreased by $226 million due to the gain associated with the FitzPatrick acquisition in first quarter 2017.

Interest expense, net decreased by $64 million due to the retirement of long-term debt.

Other, net decreased by $417 million primarily due to net unrealized and realized losses on NDT funds at Generation for the six months ended June 30, 2018 compared to net unrealized and realized gains on NDT funds for the same period in 2017.

Exelon’s effective income tax rates for the six months ended June 30, 2018 and 2017 were 9.5% and 12.1%, respectively. The decrease in the effective income tax rate for the six months ended June 30, 2018 compared to the same period in 2017 is primarily related to tax savings due to the lower federal income tax rate as a result of the TCJA at all Registrants, which is offset in Operating revenues at the Utility Registrants for the anticipated pass back of the tax savings through customer rates. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates. See Note 6 — Regulatory Matters of the

Table of Contents

Combined Notes to Consolidated Financial Statements for additional information on TCJA's impact on regulatory proceedings.

For additional information regarding the financial results for the three and six months ended June 30, 2018, including explanation of the non-GAAP measure Revenue net of purchased power and fuel expense, see the discussions of Results of Operations by Registrant below.

Adjusted (non-GAAP) Operating Earnings

Exelon’s adjusted (non-GAAP) operating earnings for the three months ended June 30, 2018 were $686 million, or $0.71 per diluted share, compared with adjusted (non-GAAP) operating earnings of $524 million, or $0.56 per diluted share for the same period in 2017. Exelon’s adjusted (non-GAAP) operating earnings for the six months ended June 30, 2018 were $1,611 million, or $1.66 per diluted share, compared with adjusted (non-GAAP) operating earnings of $1,124 million, or $1.21 per diluted share for the same period in 2017. In addition to net income, 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 information 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 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. Adjusted (non-GAAP) operating earnings is not a presentation defined under GAAP and may not be comparable to other companies’ presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Table of Contents

The following tables provide a reconciliation between net income attributable to common shareholders as determined in accordance with GAAP and adjusted (non-GAAP) operating earnings for the three and six months ended June 30, 2018 compared to the same period in 2017.

	Three Months Ended June 30,			
	2018		2017	
(All amounts in millions after tax)		Earnings per Diluted Share		Earnings per Diluted Share
Net Income Attributable to Common Shareholders	$539	$ 0.56	$95	$ 0.10
Mark-to-Market Impact of Economic Hedging Activities[a] (net of taxes of $23 and $72, respectively)	(67)	(0.07)	113	0.12
Unrealized Losses (Gains) Related to NDT Fund Investments[b] (net of taxes of $77 and $20, respectively)	81	0.08	(45)	(0.05)
Amortization of Commodity Contract Intangibles[c] (net of taxes of $0 and $8, respectively)	—	—	12	0.01
Merger and Integration Costs[d] (net of taxes of $0 and $9, respectively)	1	—	15	0.02
Long-Lived Asset Impairments[f] (net of taxes of $11 and $172, respectively)	30	0.03	268	0.29
Plant Retirements and Divestitures[g] (net of taxes of $47 and $42, respectively)	127	0.14	66	0.07
Cost Management Program[h] (net of taxes of $4 and $4, respectively)	12	0.01	6	0.01
Change in Environmental Liabilities[j] (net of taxes of $2 and $0, respectively)	5	0.01	—	—
Like-Kind Exchange Tax Position[k] (net of taxes of $0 and $66, respectively)	—	—	(26)	(0.03)
Reassessment of Deferred Income Taxes[l] (entire amount represents tax expense)	(8)	(0.01)	—	—
Noncontrolling Interests[n] (net of taxes of $7 and $5, respectively)	(34)	(0.04)	20	0.02
Adjusted (non-GAAP) Operating Earnings	$686	$ 0.71	$524	$ 0.56

198

Table of Contents

	Six Months Ended June 30,			
	2018		2017	
(All amounts in millions after tax)		Earnings per Diluted Share		Earnings per Diluted Share
Net Income Attributable to Common Shareholders	$1,125	$ 1.16	$1,086	$ 1.17
Mark-to-Market Impact of Economic Hedging Activities[(a)] (net of taxes of $46 and $91, respectively)	129	0.13	142	0.15
Unrealized Losses (Gains) Related to NDT Fund Investments[(b)] (net of taxes of $122 and $130, respectively)	147	0.15	(144)	(0.15)
Amortization of Commodity Contract Intangibles[(c)] (net of taxes of $0 and $9, respectively)	—	—	15	0.02
Merger and Integration Costs[(d)] (net of taxes of $2 and $25, respectively)	4	—	40	0.04
Merger Commitments[(e)] (net of taxes of $0 and $137, respectively)	—	—	(137)	(0.15)
Long-Lived Asset Impairments[(f)] (net of taxes of $11 and $172, respectively)	30	0.03	268	0.29
Plant Retirements and Divestitures[(g)] (net of taxes of $78 and $42, respectively)	220	0.23	66	0.07
Cost Management Program[(h)] (net of taxes of $6 and $7, respectively)	16	0.02	10	0.01
Bargain Purchase Gain[(i)] (net of taxes of $0)	—	—	(226)	(0.24)
Change in Environmental Liabilities [(j)] (net of taxes of $2 and $0, respectively)	5	0.01	—	—
Like-Kind Exchange Tax Position[(k)] (net of taxes of $0 and $66, respectively)	—	—	(26)	(0.03)
Reassessment of Deferred Income Taxes[(l)] (entire amount represents tax expense)	(8)	(0.01)	(20)	(0.02)
Tax Settlements[(m)] (net of taxes of $0 and $1, respectively)	—	—	(5)	(0.01)
Noncontrolling Interests[(n)] (net of taxes of $13 and $12, respectively)	(57)	(0.06)	55	0.06
Adjusted (non-GAAP) Operating Earnings	$1,611	$ 1.66	$1,124	$ 1.21

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. 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) Reflects the impact of net gains and losses on Generation's economic hedging activities. See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information related to Generation's hedging activities.

(b) 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.

(c) 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.

Table of Contents

(d) Primarily 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. See Note 4 — Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information related to merger and acquisition costs.

(e) 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.

(f) Primarily reflects charges to earnings related to the impairment of the EGTP assets held for sale in 2017, and in 2018 the impairment of certain wind projects at Generation.

(g) Primarily reflects accelerated depreciation and amortization expenses and one-time charges associated with Generation's decision to early retire the TMI 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 TMI 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.

(h) Represents severance and reorganization costs related to a cost management program.

(i) Represents the excess fair value of assets and liabilities acquired over the purchase price for the FitzPatrick acquisition.

(j) Represents charges to adjust the environmental reserve associated with Cotter.

(k) 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.

(l) 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 TCJA.

(m) Reflects benefits related to the favorable settlement in 2017 of certain income tax positions related to PHI’s unregulated business interests.

(n) Represents elimination from Generation’s results of the noncontrolling interests related to certain exclusion items, primarily related to the impact of unrealized gains and losses on NDT fund investments at CENG.

Significant 2018 Transactions and Developments

Regulatory Implications of the Tax Cuts and Jobs Act (TCJA)

The Utility Registrants have made filings with their respective State regulators to begin passing back to customers the ongoing annual tax savings resulting from the TCJA. The amounts being proposed to be passed back to customers reflect the annual benefit of lower income tax rates and the settlement of a portion of deferred income tax regulatory liabilities established upon enactment of the TCJA. The Utility Registrants have identified over $675 million in ongoing annual savings to be returned to customers related to TCJA from their distribution utility operations. See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Early Plant Retirements

On February 2, 2018, Exelon announced that Generation will permanently cease generation operations at Oyster Creek at the end of its current operating cycle by October 2018. Because of the decision to early retire Oyster Creek in 2018, Exelon and Generation recognized certain one-time charges in the first quarter of 2018 related to a materials and supplies inventory reserve adjustment, employee-related costs and construction work-in-progress impairments, among other items.

On July 31, 2018, Generation entered into an agreement with Holtec International and its indirect wholly owned subsidiary, Oyster Creek Environmental Protection, LLC, for the sale and decommissioning of Oyster Creek. See Note 20 — Subsequent Events of the Combined Notes to Consolidated Financial Statements for additional information.

On May 30, 2017, Generation announced it will permanently cease generation operations at Three Mile Island Generating Station (TMI) on or about September 30, 2019. The plant is currently committed to operate through May

2019.
As a result of the early nuclear plant retirement decisions at Oyster Creek and TMI, Exelon and Generation will also recognize annual incremental non-cash charges to earnings stemming from shortening the expected economic useful lives primarily related to accelerated depreciation of plant assets (including any ARC), accelerated amortization of nuclear fuel, and additional ARO accretion expense associated with the changes in decommissioning timing and cost assumptions were also

Table of Contents

recorded. The following table summarizes the actual incremental non-cash expense item incurred in 2018 and the estimated amount of incremental non-cash expense items expected to be incurred in 2018 and 2019 due to the early retirement decisions.

Income statement expense (pre-tax)	Actual Six Months Ended June 30, 2018	Projected[(a)] 2018	2019
Depreciation and amortization[(b)]			
Accelerated depreciation[(c)]	$ 289	$550	$330
Accelerated nuclear fuel amortization	34	55	5
Operating and maintenance[(d)]	28	30	5
Total	$ 351	$635	$340

(a) Actual results may differ based on incremental future capital additions, actual units of production for nuclear fuel amortization, future revised ARO assumptions, etc.

(b) Reflects incremental accelerated depreciation and amortization for TMI and Oyster Creek for the six months ended June 30, 2018. The Oyster Creek year-to-date amounts are from February 2, 2018 through June 30, 2018.

(c) Reflects incremental accelerated depreciation of plant assets, including any ARC.

(d) Primarily includes materials and supplies inventory reserve adjustments, employee-related costs and CWIP impairments.

In 2017, PSEG also made public financial challenges facing its New Jersey nuclear plants including Salem, of which Generation owns a 42.59% ownership interest. Although Salem is committed to operate through May 2021, the plant faces continued economic challenges and PSEG, as the operator of the plant, is exploring all options.

On May 23, 2018, the Governor 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. 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. 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. See Note 6 — Regulatory Matters and Note 8 - Early Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information on the new legislation and the New Jersey ZEC program.

On March 29, 2018, based on ISO-NE capacity auction results for the 2021 - 2022 planning year in which Mystic unit 9 did not clear, 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. The ISO-NE announced that it would take a three-step approach to fuel security. First, 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. Second, ISO-NE planned to file tariff revisions to allow it to retain other resources for fuel security in the capacity market if necessary in the future. Third, ISO-NE stated its intention to work with stakeholders to develop long-term market rule changes to address system resiliency considering significant reliability risks identified in ISO-NE's January 2018 fuel security report. Changes to market rules are necessary because critical units to the region, such as Mystic units 8 and 9, cannot recover future operating costs including the cost of procuring fuel. As a result of these developments, Generation completed a comprehensive review of the estimated undiscounted future cash flows of the New England asset group during the first quarter of 2018 and no impairment charge was required.

Table of Contents

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. Further developments such as the failure of ISO-NE to adopt interim and long-term solutions for reliability and fuel security could potentially result in future impairments of the New England asset group, which could be material. See Note 7 — Impairment of Long-Lived Assets and Note 8 - Early Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information.
Illinois ZEC Procurement
Pursuant to FEJA, on January 25, 2018, the ICC announced that Generation’s Clinton unit 1, Quad Cities unit 1 and Quad Cities unit 2 nuclear plants were selected as the winning bidders through the IPA's ZEC procurement event. Generation executed the ZEC procurement contracts with Illinois utilities, including ComEd, effective January 26, 2018 and began recognizing revenue. Winning bidders are entitled to compensation for the sale of ZECs retroactive to the June 1, 2017 effective date of FEJA. During the three months ended June 30, 2018, Generation recognized revenue of $52 million. During the six months ended June 30, 2018, Generation recognized revenue of $254 million, of which $150 million related to ZECs generated from June 1, 2017 through December 31, 2017.
Westinghouse Electric Company LLC Bankruptcy
On March 29, 2017, Westinghouse Electric Company LLC (Westinghouse) and its affiliated debtors filed petitions for relief under Chapter 11 of the Bankruptcy Code in the U.S. Bankruptcy Court for the Southern District of New York. On January 4, 2018, Westinghouse announced its agreement to be purchased by an affiliate of Brookfield Business Partners, LLC (Brookfield) for approximately $4.6 billion. On March 28, 2018, the Bankruptcy Court entered an Order confirming the Debtor's Second Amended Joint Plan of Reorganization which provides for the transaction with Brookfield. Closing of the transaction is expected to occur in the third quarter of 2018. Exelon has contracts with Westinghouse primarily related to Generation's purchase of nuclear fuel, as well as a variety of services and equipment purchases associated with the operation and maintenance of nuclear generating stations. In conjunction with the confirmation hearing, Exelon had filed a reservation of rights regarding reorganizing Westinghouse's assumption of all Exelon contracts. Exelon has reached an agreement with Brookfield that all Exelon contracts will be assumed by Brookfield on the closing date. Closing of the transaction is subject to numerous conditions, including regulatory approvals.
Utility Rates and Base Rate Proceedings
The Utility Registrants file base rate cases with their regulatory commissions seeking increases or decreases to their electric transmission and distribution, and gas distribution rates to recover their costs and earn a fair return on their investments. The outcomes of these regulatory proceedings impact the Utility Registrants’ current and future results of operations, cash flows and financial position.

Table of Contents

The following tables show the Utility Registrants' completed and pending distribution base rate case proceedings in 2018. See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on other regulatory proceedings.

Completed Distribution Base Rate Case Proceedings

Registrant	Jurisdiction	Approved Revenue Requirement Increase (Decrease) (in millions)	Approved Return on Equity	Completion Date	Rate Effective Date
Pepco	Maryland (Electric)	$ (15)	9.5 %	May 31, 2018	June 1, 2018
DPL	Maryland (Electric)	$ 13	9.5 %	February 9, 2018	February 9, 2018

Pending Distribution Base Rate Case Proceedings

Registrant	Jurisdiction	Requested or Settlement Revenue Requirement Increase (Decrease) (in millions)	Requested or Settlement Return on Equity	Filing or Settlement Date	Expected Completion Timing
ComEd	Illinois (Electric)	$ (23)	8.69 %	April 16, 2018	Fourth quarter 2018
PECO	Pennsylvania (Electric)	$ 82	10.95 %	March 29, 2018	Fourth quarter 2018
BGE	Maryland (Natural Gas)	$ 63	10.50 %	June 8, 2018	First quarter 2019
Pepco	District of Columbia (Electric)	$ (24)	9.525 %	December 19, 2017 (Updated on February 9, 2018 and April 17, 2018)	Third quarter 2018
DPL	Delaware (Electric)	$ (7)	9.70 %	August 17, 2017 (Updated on October 18, 2017, February 9, 2018 and June 27, 2018)	Third quarter 2018
DPL	Delaware (Natural Gas)	$ 4	10.10 %	August 17, 2017 (Updated on November 7, 2017 and February 9, 2018)	Fourth quarter 2018

See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on these base rate case proceedings.

Table of Contents

Transmission Formula Rate

The following total (decreases)/increases were included in ComEd's, BGE's, Pepco's, DPL's and ACE's 2018 annual electric transmission formula rate updates.

Annual Transmission Updates[a][b]	2018 ComEd	BGE	Pepco	DPL	ACE
Initial revenue requirement (decrease) increase	$(44)	$10	$6	$14	$4
Annual reconciliation increase (decrease)	18	4	2	13	(4)
Dedicated facilities increase[c]	—	12	—	—	—
Total revenue requirement (decrease) increase	$(26)	$26	$8	$27	$—
Allowed return on rate base[d]	8.32 %	7.61%	7.82%	7.29%	8.02%
Allowed ROE[e]	11.50%	10.50%	10.50%	10.50%	10.50%

(a) All rates are effective June 2018, subject to review by the FERC and other parties, which is due by fourth quarter 2018.

(b) The initial revenue requirement changes reflect the annual benefit of lower income tax rates effective January 1, 2018 resulting from the enactment of the TCJA of $69 million, $18 million, $13 million, $12 million and $11 million for ComEd, BGE, Pepco, DPL and ACE, respectively. They do not reflect the pass back or recovery of income tax-related regulatory liabilities or assets, including those established upon enactment of the TCJA. See further discussion above.

(c) BGE's transmission revenues include a FERC-approved dedicated facilities charge to recover the costs of providing transmission service to a specifically designated load by BGE.

(d) Represents the weighted average debt and equity return on transmission rate bases.

(e) As part of the FERC-approved settlement of ComEd’s 2007 transmission rate case, the rate of return on common equity is 11.50% and the common equity component of the ratio used to calculate the weighted average debt and equity return for the transmission formula rate is currently capped at 55%. As part of the FERC-approved settlement of the ROE complaint against BGE, Pepco, DPL and ACE, the rate of return on common equity is 10.50%, inclusive of a 50 basis point incentive adder for being a member of a regional transmission organization.

PECO Transmission Formula Rate

On May 1, 2017, PECO filed a request with FERC seeking approval to update its transmission rates and change the manner in which PECO’s transmission rate is determined from a fixed rate to a formula rate. The formula rate will be updated annually to ensure that under this rate customers pay the actual costs of providing transmission services. The formula rate filing includes a requested increase of $22 million to PECO’s annual transmission revenues and a requested rate of return on common equity of 11%, inclusive of a 50 basis point adder for being a member of a regional transmission organization. PECO requested that the new transmission rate be effective as of July 2017. On June 27, 2017, FERC issued an Order accepting the filing and suspending the proposed rates until December 1, 2017, subject to refund, and set the matter for hearing and settlement judge procedures. On May 4, 2018, the Chief Administrative Law Judge terminated settlement judge procedures and designated a new presiding judge. PECO cannot predict the final outcome of this proceeding, or the transmission formula FERC may approve.

On May 11, 2018, pursuant to the transmission formula rate request discussed above, PECO made its first annual formula rate update, which included a revenue decrease of $6 million. The revenue decrease of $6 million included an approximately $20 million reduction as a result of the tax savings associated with the TCJA. The updated transmission rate was effective June 1, 2018, subject to refund.

Table of Contents

Winter Storm-Related Costs

During March 2018 there were powerful nor'easter storms that brought a mix of heavy snow, ice and high sustained winds and gusts to the region that interrupted electric service delivery to customers in PECO's, BGE's, Pepco's, DPL's and ACE's service territories. Restoration efforts included significant costs associated with employee overtime, support from other utilities and incremental equipment, contracted tree trimming crews and supplies, which resulted in incremental operating and maintenance expense and incremental capital expenditures in the first quarter of 2018 for PECO, BGE, PHI, Pepco, DPL and ACE. In addition, PHI, Pepco, DPL and ACE recorded regulatory assets for amounts that are probable of recovery through customer rates. The impacts recorded by the Registrants for the six months ended June 30, 2018 are presented below:

	Customer Outages	(in millions) Incremental Operating & Maintenance		Incremental Capital Expenditures
Exelon	1,727,000	$ 92	(b)	$ 93
PECO	750,000	54		36
BGE	425,000	31		15
PHI[(a)]	552,000	7	(b)	42
Pepco	182,000	3	(b)	6
DPL	138,000	4	(b)	5
ACE	232,000	—	(b)	31

(a) PHI reflects the consolidated customer outages, incremental operating & maintenance and incremental capital expenditures of Pepco, DPL and ACE.

(b) Excludes amounts that were deferred and recognized as regulatory assets at Exelon, PHI, Pepco, DPL and ACE of $25 million, $25 million, $5 million, $1 million and $19 million, respectively.

Exelon’s Strategy and Outlook for 2018 and Beyond

Exelon’s value proposition and competitive advantage come from its scope and its core strengths of operational excellence and financial discipline. Exelon leverages its integrated business model to create value. Exelon’s regulated and competitive businesses feature a mix of attributes that, when combined, offer shareholders and customers a unique value proposition:

- The Utility Registrants provide a foundation for steadily growing earnings, which translates to a stable currency in our stock.
- Generation’s competitive businesses provide free cash flow to invest primarily in the utilities and in long-term, contracted assets and to reduce debt.

Exelon believes its strategy provides a platform for optimal success in an energy industry experiencing fundamental and sweeping change.

Exelon’s utility strategy is to improve reliability and operations and enhance the customer experience, while ensuring ratemaking mechanisms provide the utilities fair financial returns. The Utility Registrants only invest in rate base where it provides a benefit to customers and the community by improving reliability and the service experience or otherwise meeting customer needs. The Utility Registrants make these investments at the lowest reasonable cost to customers. Exelon seeks to leverage its scale and expertise across the utilities platform through enhanced standardization and sharing of resources and best practices to achieve improved operational and financial results. Additionally, the Utility Registrants anticipate making significant future investments in smart meter

Table of Contents

technology, transmission projects, gas infrastructure, and electric system improvement projects, providing greater reliability and improved service for our customers and a stable return for the company.

Generation’s competitive businesses create value for customers by providing innovative energy solutions and reliable, clean and affordable energy. Generation’s electricity generation strategy is to pursue opportunities that provide stable revenues and generation to load matching to reduce earnings volatility. Generation leverages its energy generation portfolio to deliver energy to both wholesale and retail customers. Generation’s customer-facing activities foster development and delivery of other innovative energy-related products and services for its customers. Generation operates in well-developed energy markets and employs an integrated hedging strategy to manage commodity price volatility. Its generation fleet, including its nuclear plants which consistently operate at high capacity factors, also provide geographic and supply source diversity. These factors help Generation mitigate the current challenging conditions in competitive energy markets.

Exelon’s financial priorities are to maintain investment grade credit metrics at each of the Registrants, to maintain optimal capital structure and to return value to Exelon’s shareholders with an attractive dividend throughout the energy commodity market cycle and through stable earnings growth. Exelon's Board of Directors has approved a dividend policy providing a raise of 5% each year for the period covering 2018 through 2020, beginning with the March 2018 dividend.

Various market, financial, regulatory, legislative and operational factors could affect the Registrants' success in pursuing their strategies. Exelon continues to assess infrastructure, operational, commercial, policy, and legal solutions to these issues. One key issue is ensuring the ability to properly value nuclear generation assets in the market, solutions to which Exelon is actively pursuing in a variety of jurisdictions and venues. See ITEM 1A. RISK FACTORS of the Exelon 2017 Form 10-K for additional information regarding market and financial factors.

Continually optimizing the cost structure is a key component of Exelon’s financial strategy. In August 2015, Exelon announced a cost management program focused on cost savings of approximately $400 million at BSC and Generation, of which approximately 60% of run-rate savings was achieved by the end of 2017 with the remainder to be fully realized in 2018. At least 75% of the savings are expected to be related to Generation, with the remaining amount related to the Utility Registrants. Additionally, in November 2017, Exelon announced a new commitment for an additional $250 million of cost savings, primarily at Generation, to be achieved by 2020. These actions are in response to the continuing economic challenges confronting all parts of Exelon’s business and industry, necessitating continued focus on cost management through enhanced efficiency and productivity.

Growth Opportunities

Management continually evaluates growth opportunities aligned with Exelon’s businesses, assets and markets, leveraging Exelon’s expertise in those areas and offering sustainable returns.

Regulated Energy Businesses. The PHI merger provides an opportunity to accelerate Exelon’s regulated growth to provide stable cash flows, earnings accretion, and dividend support. Additionally, the Utility Registrants anticipate investing approximately $26 billion over the next five years in electric and natural gas infrastructure improvements and modernization projects, including smart meter and smart grid initiatives, storm hardening, advanced reliability technologies, and transmission projects, which is projected to result in an increase to current rate base of approximately $11 billion by the end of 2022. The Utility Registrants invest in rate base where beneficial to customers and the community by increasing reliability and the service experience or otherwise meeting customer needs. These investments are made at the lowest reasonable cost to customers.

Table of Contents

See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements Exelon 2017 Form 10-K for additional information on the Smart Meter and Smart Grid Initiatives and infrastructure development and enhancement programs.

Competitive Energy Businesses. Generation continually assesses the optimal structure and composition of its generation assets as well as explores wholesale and retail opportunities within the power and gas sectors. Generation's long-term growth strategy is to ensure appropriate valuation of its generation assets, in part through public policy efforts, identify and capitalize on opportunities that provide generation to load matching as a means to provide stable earnings, and identify emerging technologies where strategic investments provide the option for significant future growth or influence in market development.

Liquidity Considerations

Each of the Registrants annually evaluates its financing plan, dividend practices and credit line sizing, focusing on maintaining its investment grade ratings while meeting its cash needs to fund capital requirements, retire debt, pay dividends, fund pension and OPEB obligations and invest in new and existing ventures. A broad spectrum of financing alternatives beyond the core financing options can be used to meet its needs and fund growth including monetizing assets in the portfolio via project financing, asset sales, and the use of other financing structures (e.g., joint ventures, minority partners, etc.). The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

Exelon Corporate, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE have unsecured syndicated revolving credit facilities with aggregate bank commitments of $0.6 billion, $5.3 billion, $1 billion, $0.6 billion, $0.6 billion, $0.3 billion, $0.3 billion and $0.3 billion, respectively. Generation also has bilateral credit facilities with aggregate maximum availability of $0.5 billion.

For additional information regarding the Registrants' liquidity for the six months ended June 30, 2018, see Liquidity and Capital Resources discussion below.

Project Financing

Generation utilizes individual project financings as a means to finance the construction of various generating asset projects. Project financing is based upon a nonrecourse financial structure, in which project debt and equity used to finance the project are paid back from the cash generated by the newly constructed asset once operational. Borrowings under these agreements are secured by the assets and equity of each respective project. The lenders do not have recourse against Exelon or Generation in the event of a default. If a specific project financing entity does not maintain compliance with its specific debt financing covenants, there could be a requirement to accelerate repayment of the associated debt or other project-related borrowings earlier than the stated maturity dates. In these instances, if such repayment was not satisfied, or restructured, the lenders or security holders would generally have rights to foreclose against the project-specific assets and related collateral. The potential requirement to satisfy its associated debt or other borrowings earlier than otherwise anticipated could lead to impairments due to a higher likelihood of disposing of the respective project-specific assets significantly before the end of their useful lives. See Note 11 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on nonrecourse debt.

Table of Contents

Other Key Business Drivers and Management Strategies
Power Markets
Price of Fuels
The use of new technologies to recover natural gas from shale deposits is increasing natural gas supply and reserves, which places downward pressure on natural gas prices and, therefore, on wholesale and retail power prices, which results in a reduction in Exelon's revenues. Forward natural gas prices have declined significantly over the last several years; in part reflecting an increase in supply due to strong natural gas production (due to shale gas development).
FERC Inquiry on Resiliency
On August 23, 2017, the DOE staff released its report on the reliability of the electric grid. One aspect of the wide-ranging report is the DOE's recognition that the electricity markets do not currently value the resiliency provided by baseload generation, such as nuclear plants. On September 28, 2017, the DOE issued a Notice of Proposed Rulemaking (NOPR) that would entitle certain eligible resilient generating units (i.e., those located in organized markets, with a 90-day supply of fuel on site, not already subject to state cost of service regulation and satisfying certain other requirements) to recover fully allocated costs and earn a fair return on equity on their investment. On January 8, 2018, FERC issued an order terminating the rulemaking docket that it initiated to address the proposed rule in the DOE NOPR, concluding the proposed rule did not sufficiently demonstrate there is a resiliency issue and that it proposed a remedy that did not appear to be just, reasonable and nondiscriminatory as required under the Federal Power Act. At the same time, FERC initiated a new proceeding to consider resiliency challenges to the bulk power system and evaluate whether additional FERC action to address resiliency would be appropriate. FERC directed each RTO and ISO to respond within 60 days to 24 specific questions about how they assess and mitigate threats to resiliency. Thereafter, interested parties submitted reply comments on May 9, 2018, and a few parties submitted further replies. Exelon has been and will continue to be an active participant in these proceedings but cannot predict the final outcome or its potential financial impact, if any, on Exelon or Generation.
Complaints and PJM Filing at FERC Seeking to Mitigate ZEC Programs
PJM and NYISO capacity markets include a Minimum Offer Price Rule (MOPR) that is intended to preclude buyers from exercising buyer market power. If a resource is subjected to a MOPR, its offer is adjusted to effectively remove the revenues it receives through a government-provided financial support program - resulting in a higher offer that may not clear the capacity market. Currently, the MOPRs in PJM and NYISO apply only to certain new gas-fired resources.
On January 9, 2017, the EPSA filed two requests with FERC: one seeking to amend a prior complaint against PJM and another seeking expedited action on a pending NYISO compliance filing in an existing proceeding. A similar complaint was recently filed at FERC. These complaints generally allege that the relevant MOPR should be expanded to also apply to existing resources including those receiving ZEC compensation under the New York CES and Illinois ZES programs. Exelon filed protests at FERC in response to each filing, arguing generally that ZEC payments provide compensation for an environmental attribute that is distinct from the energy and capacity sold in the FERC-jurisdictional markets, and therefore, are no different than other renewable support programs like the PTC and RPS programs that have generally not been subject to a MOPR. However, if successful, for Generation's facilities in PJM and NYISO that are currently receiving ZEC compensation (Quad Cities, Ginna, Fitzpatrick and Nine Mile Point), an expanded MOPR could require exclusion of ZEC compensation when bidding into future capacity auctions such that these facilities would have an increased risk of not clearing in future capacity auctions and thus no longer receiving capacity revenues during the respective ZEC programs. Any mitigation of these generating resources could have a material effect on Exelon's and Generation's future

Table of Contents

cash flows and results of operations. The same risk would also exist for the Salem facility if the NJ ZEC program is successfully implemented and Salem is selected as an eligible facility.

Separately, PJM submitted two proposed alternative capacity market reforms in April 2018 for FERC's consideration. PJM argued that either alternative will resolve any conflict between state policy support for certain resources and the need to ensure reasonable prices for non-supported resources. The first alternative was to implement a twice-run capacity clearing mechanism (known as the repricing proposal) and, if not acceptable to FERC, a second alternative that would expand the existing MOPR to both new and existing generating resources, subject to certain exemptions (known as MOPREx).

In June 2018, FERC issued an order rejecting both of PJM's proposed alternatives, finding both to be unjust and unreasonable. In the same order, FERC also addressed one of the MOPR complaints involving PJM and concluded based on that complaint and PJM's filing that PJM's existing tariff allows resources receiving out-of-market support to affect capacity prices in a manner that will cause unjust and unreasonable and unduly discriminatory rates in PJM regardless of the intent motivating the support. FERC suggested that modifying two elements of PJM's existing tariff could produce a just and reasonable replacement and asked for initial comments on its proposal by August 28, 2018. First, FERC found that an expansion of the current MOPR mechanism to cover all existing generating resources, regardless of resource type, including those receiving either ZEC or REC compensation, could protect the capacity markets from unwanted price suppression. Second, FERC preliminarily found that a modified version of PJM's existing Fixed Resource Requirement (FRR) option could enable state subsidized resources and a corresponding amount of load to be removed from the capacity market, thereby alleviating their price suppressive effects on capacity clearing prices. Under this alternative, state supported generating resources would potentially be compensated through mechanisms other than through PJM's existing market mechanism. FERC indicated that it aims to render a decision prior to January 4, 2019 and established March 21, 2016 as the refund effective date. FERC has not yet issued a decision on the second MOPR complaint involving PJM or the MOPR complaint involving NYISO. It is too early to predict the final outcome of each of these proceedings or their potential financial impact, if any, on Exelon or Generation.

Section 232 Uranium Petition

On January 16, 2018, two Canadian-owned uranium mining companies with operations in the U.S. jointly submitted a petition to the U.S. Department of Commerce (DOC) seeking relief under Section 232 of the Trade Expansion Act of 1962 (as amended) from imports of uranium products, alleging that these imports threaten national security (the Petition). The Trade Expansion Act of 1962 (the Act) was promulgated by Congress to protect essential national security industries whose survival is threatened by imports. As such, the Act authorizes the Secretary of Commerce (the Secretary) to conduct investigations to evaluate the effects of imports of any item on the national security of the U.S. The Petition alleges that the loss of a viable U.S. uranium mining industry would have a significant detrimental impact on the national, energy, and economic security of the U.S. and the ability of the country to sustain an independent nuclear fuel cycle.

On July 18, 2018, the Secretary announced that the DOC has initiated an investigation in response to the petition. The Secretary has 270 days to prepare and submit a report to President Trump, who then has 90 days to act on the Secretary's recommendations. Exelon and Generation cannot currently predict the outcome of this investigation. The relief sought by the petitioners would require U.S. nuclear reactors to purchase at least 25% of their uranium needs from domestic mines over the next 10 years, although the DOC will make an independent determination regarding an appropriate remedy should it find that imports impair national security. It is reasonably possible that if this petition is successful the resulting increase in nuclear fuel costs in future periods could have a material, unfavorable impact on Exelon's and Generation's results of operations, cash flows and financial positions.

Table of Contents

Potential DOE Order Pursuant to Defense Production Act and Federal Power Act

The DOE is considering an Order directing ISOs, for 24 months, to purchase electric energy or generation capacity from a designated list of coal and nuclear generation facilities. Based on a draft memorandum, the Order would be pursuant to DOE's authorities under the Defense Production Act and Federal Power Act, and would forestall any further actions towards retiring, decommissioning, or deactivating coal and nuclear facilities during the term of the Order. The Order would emphasize the importance of grid resiliency, in addition to grid reliability, noting that fuel security and diversity are critical components of resiliency. The DOE recognizes that the underlying economic and regulatory issues are complex and will take time resolve. The Order's 24-month duration would enable DOE to conduct additional analyses to gain a detailed understanding of location-specific vulnerabilities in U.S. energy delivery systems, while preserving certain generation facilities. Exelon has been and will continue to be an active participant in these proceedings but cannot predict the final outcome or its potential financial impact, if any, on Exelon or Generation.

Energy Demand

Modest economic growth partially offset by energy efficiency initiatives is resulting in relatively flat load growth in electricity for the Utility Registrants. ComEd, PECO, BGE, Pepco, DPL and ACE are projecting load volumes to increase by 0.7%, 0.6%, 0.7%, 0.6%, 1.0% and 2.1% respectively, in 2018 compared to 2017.

Retail Competition

Generation’s retail operations compete for customers in a competitive environment, which affect the margins that Generation can earn and the volumes that it is able to serve. Forward natural gas and power prices are expected to remain low and thus we expect retail competitors to stay aggressive in their pursuit of market share, and that wholesale generators (including Generation) will continue to use their retail operations to hedge generation output.

Strategic Policy Alignment

As part of its strategic business planning process, Exelon routinely reviews its hedging policy, dividend policy, operating and capital costs, capital spending plans, strength of its balance sheet and credit metrics, and sufficiency of its liquidity position, by performing various stress tests with differing variables, such as commodity price movements, increases in margin-related transactions, changes in hedging practices and the impacts of hypothetical credit downgrades.

Exelon's board of directors declared first quarter 2018 dividends of $0.345 per share on Exelon's common stock. The first quarter 2018 dividend was paid on March 9, 2018. The dividend increased from the fourth quarter 2017 amount to reflect the Board's decision to raise Exelon's dividend 5% each year for the period covering 2018 through 2020, beginning with the March 2018 dividend.

Exelon's board of directors declared second quarter 2018 dividends of $0.345 per share on Exelon's common stock and was paid on June 8, 2018.

Exelon's board of directors declared third quarter 2018 dividends of $0.345 per share on Exelon's common stock and is payable on September 10, 2018.

All future quarterly dividends require approval by Exelon's Board of Directors.

Hedging Strategy

Exelon’s policy to hedge commodity risk on a ratable basis over three-year periods is intended to reduce the financial impact of market price volatility. Generation is exposed to commodity price risk

Table of Contents

associated with the unhedged portion of its electricity portfolio. Generation enters into non-derivative and derivative contracts, including financially-settled swaps, futures contracts and swap options, and physical options and physical forward contracts, all with credit-approved counterparties, to hedge this anticipated exposure. Generation has hedges in place that significantly mitigate this risk for 2018 and 2019. However, Generation is exposed to relatively greater commodity price risk in the subsequent years with respect to which a larger portion of its electricity portfolio is currently unhedged. As of June 30, 2018, the percentage of expected generation hedged is 97%-100%, 71%-74% and 41%-44% for 2018, 2019, and 2020 respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted generating facilities 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. Equivalent sales represent all hedging products, such as wholesale and retail sales of power, options and swaps. Generation has been and will continue to be proactive in using hedging strategies to mitigate commodity price risk in subsequent years as well.

Generation procures oil and natural gas through long-term and short-term contracts and spot-market purchases. Nuclear fuel is obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services, coal, oil and natural gas are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation’s procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 59% of Generation’s uranium concentrate requirements from 2018 through 2022 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrate can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon’s and Generation’s results of operations, cash flows and financial positions.

The Utility Registrants mitigate commodity price risk through regulatory mechanisms that allow them to recover procurement costs from retail customers.

Environmental Legislative and Regulatory Developments

Exelon was actively involved in the Obama Administration’s development and implementation of environmental regulations for the electric industry, in pursuit of its business strategy to provide reliable, clean, affordable and innovative energy products. These efforts have most frequently involved air, water and waste controls for fossil-fueled electric generating units, as set forth in the discussion below. These regulations have had a disproportionate adverse impact on coal-fired power plants, requiring significant expenditures of capital and variable operating and maintenance expense, and have resulted in the retirement of older, marginal facilities. Due to its low emission generation portfolio, Generation has not been significantly affected by these regulations, representing a competitive advantage relative to electric generators that are more reliant on fossil fuel plants.

Through the issuance of a series of Executive Orders (EO), President Trump has initiated review of a number of EPA and other regulations issued during the Obama Administration, with the expectation that the Administration will seek repeal or significant revision of these rules. Under these EOs, each executive agency is required to evaluate existing regulations and make recommendations regarding repeal, replacement, or modification. The Administration’s actions are intended to result in less stringent compliance requirements under air, water, and waste regulations. The exact nature, extent, and timing of the regulatory changes are unknown, as well as the ultimate impact on Exelon’s and its subsidiaries results of operations and cash flows.

Table of Contents

In particular, the Administration has targeted certain existing EPA regulations for repeal, including notably the Clean Power Plan, as well as revoking many Executive Orders, reports, and guidance issued by the Obama Administration on the topic of climate change or the regulation of greenhouse gases. The Executive Order also disbanded the Interagency Working Group that developed the social cost of carbon used in rulemakings and withdrew all technical support documents supporting the calculation. Other regulations that are under review include the Clean Water Act rule relating to jurisdictional waters of the U.S., the Steam Electric Effluent Guidelines relating to waste water discharges from coal-fired power plants, the Coal Combustion Residuals rule, and the 2015 National Ambient Air Quality Standard (NAAQS) for ozone. The review of final rules could extend over several years as formal notice and comment rulemaking process proceeds.

Air Quality

Mercury and Air Toxics Standard Rule (MATS). On December 16, 2011, the EPA signed a final rule to reduce emissions of toxic air pollutants from power plants and signed revisions to the NSPS for electric generating units. The final rule, known as MATS, requires coal-fired electric generation plants to achieve high removal rates of mercury, acid gases and other metals, and to make capital investments in pollution control equipment and incur higher operating expenses. The initial compliance deadline to meet the new standards was April 16, 2015; however, facilities may have been granted an additional one or two-year extension in limited cases. Numerous entities challenged MATS in the D.C. Circuit Court, and Exelon intervened in support of the rule. In April 2014, the D.C. Circuit Court issued an opinion upholding MATS in its entirety. On appeal, the U.S. Supreme Court decided in June 2015 that the EPA unreasonably refused to consider costs in determining whether it is appropriate and necessary to regulate hazardous air pollutants emitted by electric utilities. The U.S. Supreme Court, however, did not vacate the rule; rather, it was remanded to the D.C. Circuit Court to take further action consistent with the U.S. Supreme Court’s opinion on this single issue. On April 27, 2017, the D.C. Circuit granted EPA’s motion to hold the litigation in abeyance, pending EPA’s review of the MATS rule pursuant to President Trump’s EO discussed above. Following EPA’s review and determination of its course of action for the MATS rule, the parties will have 30 days to file motions on future proceedings. Notwithstanding the Court’s order to hold the litigation in abeyance, the MATS rule remains in effect. Exelon will continue to participate in the remanded proceedings before the D.C. Circuit Court as an intervenor in support of the rule.

Clean Power Plan. On April 28, 2017, the D.C. Circuit Court issued orders in separate litigation related to the EPA’s actions under the Clean Power Plan (CPP) to amend Clean Air Act Section 111(d) regulation of existing fossil-fired electric generating units and Section 111(b) regulation of new fossil-fired electric generating units. In both cases, the Court has determined to hold the litigation in abeyance pending a determination whether the rule should be remanded to the EPA. On October 10, 2017, EPA issued a proposed rule to repeal the CPP in its entirety, based on a proposed change in the Agency’s legal interpretation of Clean Air Act Section 111(d) regarding actions that the Agency can consider when establishing the Best System of Emission Reduction (“BSER”) for existing power plants. Under the proposed interpretation, the Agency exceeded its authority under the Clean Air Act by regulating beyond individual sources of GHG emissions. The EPA has also issued an advance notice of proposed rulemaking to solicit information on systems of emission reduction that are in accord with the Agency’s proposed revised legal interpretation; namely, only by regulating emission reductions that can be implemented at and to individual sources.

2015 Ozone National Ambient Air Quality Standards (NAAQS). On April 11, 2017, the D.C. Circuit ordered that the consolidated 2015 ozone NAAQS litigation be held in abeyance pending EPA’s further review of the 2015 Rule. Concurrent with its review, the Agency issued several rounds of final ozone designations for the 2015 ozone NAAQS in December 2017 and April 2018.

Climate Change. Exelon supports comprehensive climate change legislation or regulation which balances the need to protect consumers, business and the economy with the urgent need to reduce

Table of Contents

national GHG emissions. In June 2018, Exelon joined the Climate Leadership Council, which advocates for a revenue neutral carbon tax and dividend program. In the absence of Federal legislation, the EPA has been reviewing the regulation of GHG emissions under the Clean Air Act. In addition, there have been recent developments in the international regulation of GHG emissions pursuant to the United Nations Framework Convention on Climate Change ("UNFCCC" or "Convention"). See ITEM 1. BUSINESS, "Air Quality" of the Exelon 2017 Form 10-K for additional information.

Water Quality

Section 316(b) requires that the cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. All of Generation's power generation facilities with cooling water systems are subject to the regulations. Facilities without closed-cycle recirculating systems (e.g., cooling towers) are potentially most affected by recent changes to the regulations. For Generation, those facilities are Calvert Cliffs, Clinton, Dresden, Eddystone, Fairless Hills, FitzPatrick, Ginna, Gould Street, Handley, Mystic unit 7, Nine Mile Point unit 1, Peach Bottom, Quad Cities, and Salem. See ITEM 1. BUSINESS, "Water Quality" of the Exelon 2017 Form 10-K for additional information.

Solid and Hazardous Waste

In October 2015, the first federal regulation for the disposal of coal combustion residuals (CCR) from power plants became effective. The rule classified CCR as non-hazardous waste under RCRA, and CCR continued to be regulated by most states subject to coordination with the federal regulations. In July 2018, the EPA issued a final rule amending the 2015 rule that provides more compliance flexibility to the states and owners and operators of coal ash disposal sites. Generation currently does not own or operate any such sites subject to the CCR rule. Generation previously recorded accruals consistent with state regulation for its owned coal ash sites, and as such, the CCR rule is not expected to impact Exelon's and Generation's financial results. Generation does not have sufficient information to reasonably assess the potential likelihood or magnitude of any remediation requirements that may be asserted under the CCR rule for coal ash disposal sites formerly owned by Generation. For these reasons, Generation is unable to predict whether and to what extent it may ultimately be held responsible for remediation and other costs relating to formerly owned coal ash disposal sites under the new regulations.

See Note 17 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information related to environmental matters, including the impact of environmental regulation.

Other Legislative and Regulatory Developments

Delaware Distribution System Investment Charge

On June 14, 2018, the Governor 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

On June 28, 2018, the Governor of Pennsylvania signed new legislation, which authorized the PAPUC to review and approve utility-proposed alternative rate mechanisms, 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.

Table of Contents

Employees

In January 2017, an election was held at BGE which resulted in union representation for approximately 1,394 employees. BGE and IBEW Local 410 are negotiating an initial agreement which could result in some modifications to wages, hours and other terms and conditions of employment. Negotiations have been productive and continue. No agreement has been finalized to date and management cannot predict the outcome of such negotiations. Negotiations that began in 2017 for a first collective bargaining agreement with a small unit of employees represented by Local 501 of Operating Engineers at Exelon’s Hyperion Solutions facility are ongoing. During 2017, Generation finalized CBAs with the Security Officer unions at LaSalle, Limerick and Quad Cities, which all will expire in 2020 and Dresden expiring in 2021. Additionally, during 2017, Generation acquired and combined two CBAs at Fitzpatrick into one CBA covering both craft and security employees, which will expire in 2023. Generation also successfully finalized the CBA with the IBEW union at TMI, which will expire in 2022. Prior to commencing negotiations with the Security Officer union at Braidwood, a rival union petitioned the NLRB to represent the Security Officers in lieu of the incumbent Union. An election was held, and the incumbent Union prevailed. The existing CBA was extended prior to the NLRB hearing and currently expires in August 2018. Negotiations began in June and have been productive and continue. In June 2018, an NLRB election was held involving 18 system operators at the ACE control room seeking potential representation by IBEW Local 210. The election was certified on July 9, 2018, recognizing IBEW Local 210 as the representative of ACE system operators. On July 23, 2018, ACE filed a Request for Review by the NLRB of the Regional Director's June 15, 2018 decision finding that the system operators are not supervisors under the National Labor Relations Act. The request is pending.

Critical Accounting Policies and Estimates

Revenue Recognition (All Registrants)

Sources of Revenue and Determination of Accounting Treatment

The Registrants earn revenues from various business activities including: the sale of power and energy-related products, such as natural gas, capacity, and other commodities in non-regulated markets (wholesale and retail); the sale and delivery of power and natural gas in regulated markets; and the provision of other energy-related non-regulated products and services.

The accounting treatment for revenue recognition is based on the nature of the underlying transaction and applicable authoritative guidance. The Registrants primarily apply the Revenue from Contracts with Customers, Derivative and Alternative Revenue Program (ARP) guidance to recognize revenue as discussed in more detail below.

Revenue from Contracts with Customers

Under the Revenue from Contracts with Customers guidance, the Registrants recognize revenues in the period in which the performance obligations within contracts with customers are satisfied, which generally occurs when power, natural gas, and other energy-related commodities are physically delivered to the customer. Transactions of the Registrants within the scope of Revenue from Contracts with Customers generally include non-derivative agreements, contracts that are designated as normal purchases and normal sales (NPNS), sales to utility customers under regulated service tariffs, and spot-market energy commodity sales, including settlements with independent system operators.

The determination of Generation’s and the Utility Registrants' retail power and natural gas sales to individual customers is based on systematic readings of customer meters, generally on a monthly basis. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and corresponding unbilled revenue is recorded. The measurement of unbilled

Table of Contents

revenue is affected by the following factors: daily customer usage measured by generation or gas throughput volume, customer usage by class, losses of energy during delivery to customers and applicable customer rates. Increases or decreases in volumes delivered to the utilities' customers and favorable or unfavorable rate mix due to changes in usage patterns in customer classes in the period could be significant to the calculation of unbilled revenue. In addition, revenues may fluctuate monthly as a result of customers electing to use an alternate supplier, since unbilled commodity revenues are not recorded for these customers. Changes in the timing of meter reading schedules and the number and type of customers scheduled for each meter reading date also impact the measurement of unbilled revenue; however, total operating revenues would remain materially unchanged.

See Note 5 — Accounts Receivable of the Exelon 2017 Form 10-K for additional information on unbilled revenue.

See Note 1 — Significant Accounting Policies and Note 5 — Revenue from Contracts with Customers of the Combined Notes to Consolidated Financial Statements for additional information on the impacts of the new revenue accounting standard effective for annual reporting periods beginning on or after December 15, 2017.

Derivative Revenues

The Registrants record revenues and expenses using the mark-to-market method of accounting for transactions that are accounted for as derivatives. These derivative transactions primarily relate to commodity price risk management activities. Mark-to-market revenues and expenses include: inception gains or losses on new transactions where the fair value is observable, unrealized gains and losses from changes in the fair value of open contracts, and realized gains and losses.

Alternative Revenue Program Revenues

Certain of the Utility Registrants' ratemaking mechanisms qualify as Alternative Revenue Programs (ARPs) if they (i) are established by a regulatory order and allow for automatic adjustment to future rates, (ii) provide for additional revenues (above those amounts currently reflected in the price of utility service) that are objectively determinable and probable of recovery, and (iii) allow for the collection of those additional revenues within 24 months following the end of the period in which they were recognized. For mechanisms that meet these criteria, which include the Utility Registrants' formula rate and revenue decoupling mechanisms, the Utility Registrants adjust revenue and record an offsetting regulatory asset or liability once the condition or event allowing additional billing or refund has occurred. The ARP revenues presented in the Utility Registrants' Consolidated Statements of Operations and Comprehensive Income include both: (i) the recognition of "originating" ARP revenues (when the regulator-specified condition or event allowing for additional billing or refund has occurred) and (ii) an equal and offsetting reversal of the "originating" ARP revenues as those amounts are reflected in the price of utility service and recognized as Revenue from Contracts with Customers.

ComEd records ARP revenue for its best estimate of the electric distribution, energy efficiency, and transmission revenue impacts resulting from future changes in rates that ComEd believes are probable of approval by the ICC and FERC in accordance with its formula rate mechanisms. BGE, Pepco and DPL record ARP revenue for their best estimate of the electric and natural gas distribution revenue impacts resulting from future changes in rates that they believe are probable of approval by the MDPSC and/or DCPSC in accordance with their revenue decoupling mechanisms. PECO, BGE, Pepco, DPL and ACE record ARP revenue for their best estimate of the transmission revenue impacts resulting from future changes in rates that they believe are probable of approval by FERC in accordance with their formula rate mechanisms. Estimates of the current year revenue requirement are based on actual and/or forecasted costs and investments in rate base for the period and the rates of return on common equity and associated regulatory capital structure allowed under the applicable tariff. The estimated

Table of Contents

reconciliation can be affected by, among other things, variances in costs incurred, investments made, allowed ROE, and actions by regulators or courts.

See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Management of each of the Registrants makes a number of significant estimates, assumptions and judgments in the preparation of its financial statements. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — CRITICAL ACCOUNTING POLICIES AND ESTIMATES in Exelon’s, Generation’s, ComEd’s, PECO’s, BGE’s, PHI's, Pepco's, DPL's and ACE's combined 2017 Form 10-K for a discussion of the estimates and judgments necessary in the Registrants’ accounting for AROs, goodwill, purchase accounting, unamortized energy assets and liabilities, asset impairments, depreciable lives of property, plant and equipment, defined benefit pension and other postretirement benefits, regulatory accounting, derivative instruments, taxation, contingencies, revenue recognition and allowance for uncollectible accounts. At June 30, 2018, the Registrants’ critical accounting policies and estimates had not changed significantly from December 31, 2017.

Results of Operations by Registrant

Net Income (Loss) Attributable to Common Shareholders by Registrant

	Three Months Ended June 30,		Favorable (Unfavorable) Variance	Six Months Ended June 30,		Favorable (Unfavorable) Variance
	2018	2017		2018	2017	
Exelon	$539	$95	$ 444	$1,125	$1,086	$ 39
Generation	178	(235)	413	314	184	130
ComEd	164	118	46	329	259	70
PECO	96	88	8	210	215	(5)
BGE	51	45	6	179	169	10
PHI	84	66	18	149	205	(56)
Pepco	54	43	11	85	101	(16)
DPL	26	19	7	57	76	(19)
ACE	8	8	—	15	36	(21)

216

Table of Contents

Results of Operations — Generation

	Three Months Ended June 30, 2018	2017	Favorable (Unfavorable) Variance	Six Months Ended June 30, 2018	2017	Favorable (Unfavorable) Variance
Operating revenues	$4,579	$4,216	$ 363	$10,090	$9,093	$ 997
Purchased power and fuel expense	2,280	2,157	(123)	5,573	4,955	(618)
Revenues net of purchased power and fuel expense[(a)]	2,299	2,059	240	4,517	4,138	379
Other operating expenses						
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 other operating expenses	2,018	2,486	468	3,942	4,422	480
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

(a) Generation evaluates its operating performance using the measure of revenue net of purchased power and fuel expense. Generation believes that revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income Attributable to Membership Interest

Three Months Ended June 30, 2018 Compared to Three Months Ended June 30, 2017. Generation's Net income attributable to membership interest for the three months ended June 30, 2018 increased compared to the same period in 2017, primarily due to higher Revenue net of purchased power and fuel expense, lower Operating and maintenance expenses, partially offset by higher Depreciation and amortization expenses, lower Other income and higher income taxes. The increase

Table of Contents

in Revenue net of purchased power and fuel expense primarily relates to mark-to-market gains in 2018 compared to losses in 2017, increased capacity prices, decreased nuclear outage days, the impact of the Illinois ZES and the impacts of Generation's natural gas portfolio, partially offset by lower realized energy prices and lower energy efficiency revenues. The decrease in Operating and maintenance expense is primarily due to the impairment of EGTP assets held for sale in 2017, decreased nuclear outage days in 2018, decreased spending related to energy efficiency projects, decreased costs related to the sale of Generation's electrical contracting business and one-time charges related to Generation's decision to early retire the TMI nuclear facility in 2017, partially offset by long-lived asset impairments of certain merchant wind assets in West Texas in 2018. The increase in Depreciation and amortization is primarily due to accelerated depreciation and amortization expenses associated with Generation's decision to early retire the Oyster Creek and TMI nuclear facilities. The decrease in Other income is primarily due to the change in realized and unrealized gains and losses on NDT funds. The decrease in income taxes is primarily due to tax savings related to the TCJA.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017. Generation's Net income attributable to membership interest for the six months ended June 30, 2018 increased compared to the same period in 2017, primarily due to higher Revenue net of purchased power and fuel expense, lower Operating and maintenance expenses and higher Gain on sales of assets and businesses, partially offset by higher Depreciation and amortization expenses, a Bargain purchase gain in 2017, lower Other income, and higher Net income attributable to noncontrolling interests. The increase in Revenue net of purchased power and fuel expense primarily relates to the impacts of the New York CES and Illinois ZES (including the impact of zero emission credits generated in Illinois from June 1, 2017 through December 31, 2017), increased capacity prices, the acquisition of the FitzPatrick nuclear facility, decreased nuclear outage days, decreased mark-to-market losses in 2018 compared to 2017, impacts of Generation's natural gas portfolio and the addition of two combined-cycle gas turbines in Texas, partially offset by the impact of the deconsolidation of EGTP in 2017, the conclusion of the Ginna Reliability Support Services Agreement, lower energy efficiency revenues and lower realized energy prices. The decrease in Operating and maintenance is primarily due to the impairment of EGTP assets held for sale in 2017, decreased nuclear outage days in 2018, one-time charges associated with Generation's decision to early retire the TMI nuclear facility in 2017, certain costs associated with mergers and acquisitions related to the PHI and FitzPatrick acquisitions, and the impact of a supplemental NEIL distribution, partially offset by long-lived asset impairments of certain merchant wind assets in West Texas in 2018 and one-time charges associated with Generation's decision to early retire the Oyster Creek facility in 2018. The increase in Gain on sales of assets and businesses is primarily due to Generation's sale of its electrical contracting business. The increase in Depreciation and amortization is primarily due to accelerated depreciation and amortization expenses associated with Generation's decision to early retire the Oyster Creek and TMI nuclear facilities. The Bargain purchase gain in 2017 is due to the acquisition of the FitzPatrick nuclear facility. The decrease in Other income is primarily due to the change in unrealized gains and losses on NDT funds. The increase in income taxes is primarily due to lower income taxes in 2017 due to Generation's 2017 Net loss.

Revenues Net of Purchased Power and Fuel Expense

The basis for Generation's reportable segments is the integrated management of its electricity business that is located in different geographic regions, and largely representative of the footprints of ISO/RTO and/or NERC regions, which utilize multiple supply sources to provide electricity through various distribution channels (wholesale and retail). Generation's hedging strategies and risk metrics are also aligned with these same geographic regions. Descriptions of each of Generation's six reportable segments are as follows:

- Mid-Atlantic represents operations in the eastern half of PJM, which includes New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of Pennsylvania and North Carolina.

Table of Contents

- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Pennsylvania, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the United States footprint of MISO, excluding MISO's Southern Region, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
- New York represents operations within ISO-NY, which covers the state of New York in its entirety.
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.
- Other Power Regions:
- South represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
- West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.
- Canada represents operations across the entire country of Canada and includes AESO, OIESO and the Canadian portion of MISO.

The following business activities are not allocated to a region, and are reported under Other: natural gas, as well as other miscellaneous business activities that are not significant to Generation's overall operating revenues or results of operations. Further, the following activities are not allocated to a region, and are reported in Other: amortization of certain intangible assets relating to commodity contracts recorded at fair value from mergers and acquisitions; accelerated nuclear fuel amortization associated with nuclear decommissioning; and other miscellaneous revenues.
Generation evaluates the operating performance of its electric business activities using the measure of Revenue net of purchased power and fuel expense, which is a non-GAAP measurement. Generation's operating revenues include all sales to third parties and affiliated sales to the Utility Registrants. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for owned generation and fuel costs associated with tolling agreements.

Table of Contents

For the three and six months ended June 30, 2018 and 2017, Generation's Revenue net of purchased power and fuel expense by region were as follows:

	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Variance	% Change	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017	Variance	% Change
Mid-Atlantic[a]	$735	$783	$ (48)	(6.1)%	$1,586	$1,557	$ 29	1.9 %
Midwest[b]	772	728	44	6.0 %	1,631	1,443	188	13.0 %
New England	96	147	(51)	(34.7)%	216	257	(41)	(16.0)%
New York[d]	266	270	(4)	(1.5)%	549	415	134	32.3 %
ERCOT	82	70	12	17.1 %	118	138	(20)	(14.5)%
Other Power Regions	90	90	—	— %	208	152	56	36.8 %
Total electric revenue net of purchased power and fuel expense	2,041	2,088	(47)	(2.3)%	4,308	3,962	346	8.7 %
Proprietary Trading	29	7	22	314.3 %	35	7	28	400.0 %
Mark-to-market gains (losses)	90	(184)	274	(148.9)%	(175)	(233)	58	(24.9)%
Other[c]	139	148	(9)	(6.1)%	349	402	(53)	(13.2)%
Total revenue net of purchased power and fuel expense	$2,299	$2,059	$ 240	11.7 %	$4,517	$4,138	$ 379	9.2 %

(a) Results of transactions with PECO and BGE are included in the Mid-Atlantic region. Results of transactions with Pepco, DPL and ACE are included in the Mid-Atlantic region.

(b) Results of transactions with ComEd are included in the Midwest region.

(c) Other represents activities not allocated to a region. See text above for a description of included activities. Includes amortization of intangible assets related to commodity contracts recorded at fair value of a $20 million decrease to revenue net of purchased power and fuel expense for the three months ended June 30, 2017, and accelerated nuclear fuel amortization associated with announced early plant retirements as discussed in Note 8 — Early Plant Retirements of the Combined Notes to Consolidated Financial Statements of a $20 million decrease and $2 million decrease to revenue net of purchased power and fuel expense for the three months ended June 30, 2018 and 2017, respectively. Also includes amortization of intangible assets related to commodity contracts recorded at fair value of a $22 million decrease to revenue net of purchased power and fuel expense for the six months ended June 30, 2017, and accelerated nuclear fuel amortization associated with announced early plant retirements as discussed in Note 8 — Early Plant Retirements of the Combined Notes to Consolidated Financial Statements of a $34 million decrease and $2 million decrease to revenue net of purchased power and fuel expense for the six months ended June 30, 2018 and 2017, respectively.

(d) Includes the ownership of the FitzPatrick nuclear facility from March 31, 2017.

Table of Contents

Generation’s supply sources by region are summarized below:

Supply source (GWhs)	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Variance	% Change	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017	Variance	% Change
Nuclear Generation								
Mid-Atlantic[a]	16,498	15,246	1,252	8.2 %	32,727	31,790	937	2.9 %
Midwest	23,100	22,592	508	2.2 %	46,698	45,061	1,637	3.6 %
New York[a][c]	6,125	6,227	(102)	(1.6)%	13,239	10,718	2,521	23.5 %
Total Nuclear Generation	45,723	44,065	1,658	3.8 %	92,664	87,569	5,095	5.8 %
Fossil and Renewables								
Mid-Atlantic	907	899	8	0.9 %	1,807	1,734	73	4.2 %
Midwest	321	417	(96)	(23.0)%	776	835	(59)	(7.1)%
New England	816	1,925	(1,109)	(57.6)%	2,851	4,002	(1,151)	(28.8)%
New York	1	1	—	— %	2	2	—	— %
ERCOT	2,303	2,315	(12)	(0.5)%	5,252	3,684	1,568	42.6 %
Other Power Regions	2,221	2,084	137	6.6 %	4,214	3,507	707	20.2 %
Total Fossil and Renewables	6,569	7,641	(1,072)	(14.0)%	14,902	13,764	1,138	8.3 %
Purchased Power								
Mid-Atlantic	557	2,901	(2,344)	(80.8)%	1,323	6,299	(4,976)	(79.0)%
Midwest	223	413	(190)	(46.0)%	559	801	(242)	(30.2)%
New England	5,953	4,343	1,610	37.1 %	11,390	9,407	1,983	21.1 %
New York	—	—	—	— %	—	28	(28)	(100.0)%
ERCOT	2,320	1,871	449	24.0 %	3,692	4,525	(833)	(18.4)%
Other Power Regions	4,502	3,507	995	28.4 %	8,635	6,375	2,260	35.5 %
Total Purchased Power	13,555	13,035	520	4.0 %	25,599	27,435	(1,836)	(6.7)%
Total Supply/Sales by Region								
Mid-Atlantic[b]	17,962	19,046	(1,084)	(5.7)%	35,857	39,823	(3,966)	(10.0)%
Midwest[b]	23,644	23,422	222	0.9 %	48,033	46,697	1,336	2.9 %
New England	6,769	6,268	501	8.0 %	14,241	13,409	832	6.2 %
New York	6,126	6,228	(102)	(1.6)%	13,241	10,748	2,493	23.2 %
ERCOT	4,623	4,186	437	10.4 %	8,944	8,209	735	9.0 %
Other Power Regions	6,723	5,591	1,132	20.2 %	12,849	9,882	2,967	30.0 %
Total Supply/Sales by Region	65,847	64,741	1,106	1.7 %	133,165	128,768	4,397	3.4 %

(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 and BGE in the Mid-Atlantic region, affiliate sales to ComEd in the Midwest region and affiliate sales to Pepco, DPL and ACE in the Mid-Atlantic region.
(c) Includes the ownership of the FitzPatrick nuclear facility from March 31, 2017.

221

Table of Contents

Mid-Atlantic

Three Months Ended June 30, 2018 Compared to Three Months Ended June 30, 2017. The $48 million decrease in Revenue net of purchased power and fuel expense in the Mid-Atlantic primarily reflects lower realized energy prices, partially offset by decreased nuclear outage days and increased capacity prices.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017. The $29 million increase in Revenue net of purchased power and fuel expense in the Mid-Atlantic primarily reflects decreased nuclear outage days and increased capacity prices, partially offset by lower realized energy prices.

Midwest

Three Months Ended June 30, 2018 Compared to Three Months Ended June 30, 2017. The $44 million increase in Revenue net of purchased power and fuel expense in the Midwest was primarily due to the impact of the Illinois ZES, increased capacity prices, and decreased nuclear outage days, partially offset by lower realized energy prices.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017. The $188 million increase in Revenue net of purchased power and fuel expense in the Midwest was primarily due to the impact of the Illinois ZES (including the impact of zero emission credits generated in Illinois from June 1, 2017 through December 31, 2017), decreased nuclear outage days, and increased capacity prices, partially offset by lower realized energy prices.

New England

Three Months Ended June 30, 2018 Compared to Three Months Ended June 30, 2017. The $51 million decrease in Revenue net of purchased power and fuel expense in New England primarily reflects lower realized energy prices, partially offset by increased capacity prices.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017. The $41 million decrease in Revenue net of purchased power and fuel expense in New England primarily reflects lower realized energy prices, partially offset by increased capacity prices.

New York

Three Months Ended June 30, 2018 Compared to Three Months Ended June 30, 2017. The $4 million decrease in Revenue net of purchased power and fuel expense in New York was primarily due to increased nuclear outage days which resulted in decreased ZEC revenues related to New York CES.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017. The $134 million increase in Revenue net of purchased power and fuel expense in New York was primarily due to the impact of the New York CES and the acquisition of FitzPatrick, partially offset by the conclusion of the Ginna Reliability Support Service Agreement.

ERCOT

Three Months Ended June 30, 2018 Compared to Three Months Ended June 30, 2017. The $12 million increase in Revenue net of purchased power and fuel expense in ERCOT was primarily due to higher realized energy prices.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017. The $20 million decrease in Revenue net of purchased power and fuel expense in ERCOT was primarily due to

Table of Contents

the deconsolidation of EGTP in 2017 and lower realized energy prices, partially offset by the addition of two combined-cycle gas turbines in Texas.

Other Power Regions

Three Months Ended June 30, 2018 Compared to Three Months Ended June 30, 2017. There was an immaterial change in Revenue net of purchased power and fuel expense in Other Power Regions.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017. The $56 million increase in Revenue net of purchased power and fuel expense in Other Power Regions was primarily due to higher realized energy prices.

Proprietary Trading

Three Months Ended June 30, 2018 Compared to Three Months Ended June 30, 2017. The $22 million increase in Revenue net of purchased power and fuel expense in Proprietary Trading was primarily due to congestion activity.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017. The $28 million increase in Revenue net of purchased power and fuel expense in Proprietary Trading was primarily due to congestion activity.

Mark-to-market

Three Months Ended June 30, 2018 Compared to Three Months Ended June 30, 2017. Mark-to-market gains on economic hedging activities were $90 million for the three months ended June 30, 2018 compared to losses of $184 million for the three months ended June 30, 2017. See Notes 9 — Fair Value of Financial Assets and Liabilities and 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on gains and losses associated with mark-to-market derivatives.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017. Mark-to-market losses on economic hedging activities were $175 million for the six months ended June 30, 2018 compared to losses of $233 million for the six months ended June 30, 2017. See Notes 9 — Fair Value of Financial Assets and Liabilities and 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on gains and losses associated with mark-to-market derivatives.

Other

Three Months Ended June 30, 2018 Compared to Three Months Ended June 30, 2017. The $9 million decrease in Revenue net of purchased power and fuel expense in Other was due to the decline in revenues related to the energy efficiency business and accelerated nuclear fuel amortization associated with announced early plant retirements as discussed in Note 8 — Early Plant Retirements of the Combined Notes to Consolidated Financial Statements, partially offset by Generation's higher natural gas portfolio optimization and the absence of amortization of energy contracts recorded at fair value associated with prior acquisitions.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017. The $53 million decrease in Revenue net of purchased power and fuel expense in Other was due to the decline in revenues related to the energy efficiency business and accelerated nuclear fuel amortization associated with announced early plant retirements as discussed in Note 8 — Early Plant Retirements of the Combined Notes to Consolidated Financial Statements, partially offset by Generation's higher natural gas portfolio optimization and the absence of amortization of energy contracts recorded at fair value associated with prior acquisitions.

Table of Contents

Nuclear Fleet Capacity Factor

The following table presents nuclear fleet operating data for the three and six months ended June 30, 2018 compared to the same period in 2017 for the Generation-operated plants. The nuclear fleet capacity factor presented in the table is defined as the ratio of the actual output of a plant over a period of time to its output if the plant had operated at full average annual mean capacity for that time period. Generation considers capacity factor to be a useful measure to analyze the nuclear fleet performance between periods. Generation has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, these measures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or be more useful than the GAAP information provided elsewhere in this report.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Nuclear fleet capacity factor[a]	93.2%	90.9%	94.8%	92.4%
Refueling outage days[a]	94	125	162	220
Non-refueling outage days[a]	2	12	8	20

(a) Reflects ownership percentage of stations operated by Exelon. Excludes Salem, which is operated by PSEG Nuclear, LLC. Includes the ownership of the FitzPatrick nuclear facility from March 31, 2017.

Table of Contents

Operating and Maintenance Expense

The changes in Operating and maintenance expense for the three and six months ended June 30, 2018 as compared to the same period in 2017, consisted of the following:

	Three Months Ended June 30, 2018 Increase (Decrease)[a]	Six Months Ended June 30, 2018 Increase (Decrease)[a]
Labor, other benefits, contracting, materials[b]	$ (60)	$ (113)
Nuclear refueling outage costs, including the co-owned Salem plants[c]	(64)	(96)
Corporate allocations	(1)	7
Insurance[d]	(3)	(36)
Merger and integration costs[e]	(18)	(55)
Plant retirements and divestitures[f]	(69)	(42)
Change in environmental liabilities[g]	7	7
Cost management program	5	4
Long-lived asset impairments[h]	(379)	(378)
Pension and non-pension postretirement benefits expense	(7)	(10)
Allowance for uncollectible accounts	(11)	(10)
Accretion expense	(5)	(3)
Other	11	(22)
Decrease in Operating and maintenance expense	$ (594)	$ (747)

(a) The financial results include Generation's acquisition of the FitzPatrick nuclear generating station from March 31, 2017.

(b) Primarily reflects decreased spending related to energy efficiency projects and decreased costs related to the sale of Generation's electrical contracting business in 2018.

(c) Primarily reflects a decrease in the number of nuclear outage days.

(d) Primarily reflects the impact of a supplemental NEIL insurance distribution.

(e) Primarily reflects certain costs associated with mergers and acquisitions, including, if and when applicable, professional fees, employee-related expenses and integration activities related to the PHI and FitzPatrick acquisitions in 2017, and the PHI acquisition in 2018.

(f) Primarily reflects one-time charges associated with Generation's decision to early retire the Oyster Creek nuclear facility in 2018 and the TMI nuclear facility in 2017.

(g) Primarily reflects charges to adjust the environmental reserve associated with Cotter.

(h) Primarily reflects charges to earnings related to the impairment of the EGTP assets held for sale in 2017, and in 2018 the impairment of certain wind projects at Generation.

Depreciation and Amortization Expense

Depreciation and amortization expense for the three and six months ended June 30, 2018 compared to the same period in 2017 increased primarily due to accelerated depreciation and amortization due to Generation's decision to early retire the Oyster Creek and TMI nuclear facilities.

Taxes Other Than Income

Taxes other than income, which can vary period to period, include non-income municipal and state utility taxes, real estate taxes and payroll taxes. Taxes other than income for the three and six months ended June 30, 2018 compared to the same period in 2017 remained relatively stable.

225

Table of Contents

Gain on Sales of Assets and Businesses
Gain on sales of assets and businesses for the three and six months ended June 30, 2018 compared to the same period in 2017 increased primarily due to Generation's 2018 sale of its electrical contracting business.
Bargain Purchase Gain
Bargain purchase gain for the three and six months ended June 30, 2018 compared to the same period in 2017 decreased as a result of the gain associated with the FitzPatrick acquisition in 2017. See Note 4 — Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.
Interest Expense, Net
Interest expense, net for the three and six months ended June 30, 2018 compared to the same period in 2017 primarily reflects decreased interest expense due to the retirement of long-term debt.
Other, Net
Other, net for the three and six months ended June 30, 2018 compared to the same period in 2017 decreased primarily due to the change in the realized and unrealized gains and losses related to NDT funds of Non-Regulatory Agreement Units as described in the table below. Other, net also reflects $3 million and $92 million for the three months ended June 30, 2018 and 2017, respectively, and $(4) million and $37 million for the six months ended June 30, 2018 and 2017, respectively, related to the contractual elimination of income tax expense (benefit) associated with the NDT funds of the Regulatory Agreement Units. See Note 13 — Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for additional information regarding NDT funds.
The following table provides unrealized and realized gains and losses on the NDT funds of the Non-Regulatory Agreement Units recognized in Other, net for the three and six months ended June 30, 2018 and 2017:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Net unrealized (losses) gains on decommissioning trust funds	$(120)	$ 70	$(215)	$235
Net realized gains on sale of decommissioning trust funds	108	40	135	49

Equity in Losses of Unconsolidated Affiliates
Equity in losses of unconsolidated affiliates for the three and six months ended June 30, 2018 compared to the same period in 2017 remained relatively stable.
Effective Income Tax Rate
Generation's effective income tax rate was 11.0% and 39.5% for the three months ended June 30, 2018 and 2017, respectively. Generation's effective income tax rate was 7.8% and (15.8)% for the six months ended June 30, 2018 and 2017, respectively. The decrease in the effective income tax rate for the three and six months ended June 30, 2018 compared to the same periods in 2017 is primarily related to tax savings due to the lower federal income tax rate as a result of the TCJA. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information of the change in the effective income tax rate.

Table of Contents

Results of Operations — ComEd

	Three Months Ended June 30, 2018	2017	Favorable (Unfavorable) Variance	Six Months Ended June 30, 2018	2017	Favorable (Unfavorable) Variance
Operating revenues	$1,398	$1,357	$ 41	$2,910	$2,656	$ 254
Purchased power expense	477	378	(99)	1,082	713	(369)
Revenues net of purchased power expense[(a)(b)]	921	979	(58)	1,828	1,943	(115)
Other operating expenses						
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 other operating expenses	634	660	26	1,253	1,310	57
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) ComEd evaluates its operating performance using the measure of Revenue net of purchased power expense. ComEd believes that Revenue net of purchased power expense is a useful measurement because it provides information that can be used to evaluate its operational performance. In general, ComEd only earns margin based on the delivery and transmission of electricity. ComEd has included its discussion of Revenue net of purchased power expense below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

(b) For regulatory recovery mechanisms, including ComEd's electric distribution and transmission formula rates, and riders, 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).

Net Income

Three Months Ended June 30, 2018 Compared to Three Months Ended June 30, 2017. ComEd's Net income for the three months ended June 30, 2018 was higher than the same period in 2017 primarily due to higher electric distribution and energy efficiency formula rate earnings as well as additional tax and interest recorded in the second quarter of 2017 relating to Exelon's like-kind exchange tax position. The TCJA did not significantly impact ComEd's net income for the three months ended June 30, 2018 as the favorable income tax impacts were predominantly offset by lower revenues resulting from the pass back of the tax savings through customer rates.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017. ComEd's Net income for the six months ended June 30, 2018 was higher than the same period in 2017 primarily due to higher electric distribution and energy efficiency formula rate earnings as well as additional tax

Table of Contents

and interest recorded in the second quarter of 2017 relating to Exelon's like-kind exchange tax position. The TCJA did not significantly impact ComEd's net income for the six months ended June 30, 2018 as the favorable income tax impacts were predominantly offset by lower revenues resulting from the pass back of the tax savings through customer rates.

Revenues Net of Purchased Power Expense

There are certain drivers of Operating revenues that are fully offset by their impact on Purchased power expense, such as commodity, REC, and ZEC procurement costs and participation in customer choice programs. ComEd is permitted to recover electricity, REC, and ZEC procurement costs from retail customers without mark-up. Therefore, fluctuations in these costs have no impact on Revenue net of purchased power expense. See Note 3 — Regulatory Matters of the Exelon 2017 Form 10-K for additional information on ComEd's electricity procurement process.

All ComEd customers have the choice to purchase electricity from a competitive electric generation supplier. Customer choice programs do not impact ComEd's volume of deliveries but do affect ComEd's Operating revenues related to supplied energy, which is fully offset in Purchased power expense. Therefore, customer choice programs have no impact on Revenue net of purchased power expense.

Retail deliveries purchased from competitive electric generation suppliers (as a percentage of kWh sales) for the three and six months ended June 30, 2018 and 2017, consisted of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Electric	70%	71%	69%	71%

Retail customers purchasing electric generation from competitive electric generation suppliers at June 30, 2018 and 2017 consisted of the following:

	June 30, 2018		June 30, 2017	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	1,337,900	33 %	1,382,600	35 %

The changes in ComEd's Revenue net of purchased power expense for the three and six months ended June 30, 2018 compared to the same period in 2017 consisted of the following:

	Three Months Ended June 30, 2018 Increase (Decrease)	Six Months Ended June 30, 2018 Increase (Decrease)
Electric distribution revenue	$ (35)	$ (67)
Transmission revenue	(9)	(15)
Energy efficiency revenue[(a)]	10	17
Regulatory required programs[(a)]	(37)	(94)
Uncollectible accounts recovery, net	1	3
Other	12	41
Total decrease	$ (58)	$ (115)

(a) Beginning on June 1, 2017, ComEd is deferring energy efficiency costs as a regulatory asset that will be recovered through the energy efficiency formula rate over the weighted average useful life of the related energy efficiency measures.

228

Table of Contents

Revenue Decoupling. The demand for electricity is affected by weather conditions. Under FEJA, ComEd revised its electric distribution rate formula effective January 1, 2017 to eliminate the favorable and unfavorable impacts on Operating revenues associated with variations in delivery volumes associated with above or below normal weather, numbers of customers or usage per customer.

Heating and cooling degree-days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree-days for a 30-year period in ComEd's service territory with cooling degree-days generally having a more significant impact to ComEd, particularly during the summer months. The changes in heating and cooling degree-days in ComEd's service territory for the three and six months ended June 30, 2018 and 2017, consisted of the following:

Heating and Cooling Degree-Days				% Change	
Three Months Ended June 30,	2018	2017	Normal	2018 vs. 2017	2018 vs. 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,					
Heating Degree-Days	3,937	3,227	3,875	22.0 %	1.6 %
Cooling Degree-Days	364	263	241	38.4 %	51.0 %

Electric Distribution Revenue. EIMA and FEJA provide for a performance-based formula rate, which requires an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. Electric distribution revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered, and allowed ROE. ComEd's allowed ROE is the annual average rate on 30-year treasury notes plus 580 basis points. In addition, ComEd's allowed ROE is subject to reduction if ComEd does not deliver the reliability and customer service benefits to which it has committed over the ten-year life of the investment program. Electric distribution revenue decreased during the three and six months ended June 30, 2018, primarily due to the impact of the lower federal income tax rate, partially offset by increased revenues due to higher rate base and increased depreciation expense as compared to the same period in 2017. See Depreciation and amortization expense discussions below and Note 6 — Regulatory Matters and Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Transmission Revenue. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, capital investments being recovered and the highest daily peak load, which is updated annually in January based on the prior calendar year. Generally, increases/decreases in the highest daily peak load will result in higher/lower transmission revenue. For the three and six months ended June 30, 2018, ComEd recorded decreased transmission revenue primarily due to the decreased peak load, partially offset by increased revenues due to higher rate base and increased depreciation expense as compared to the same period in 2017. See Operating and maintenance expense below and Note 6 — Regulatory Matters and Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Energy Efficiency Revenue. Beginning June 1, 2017, FEJA provides for a performance-based formula rate, which requires an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. Under FEJA, energy efficiency revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered, and allowed ROE. ComEd's allowed ROE is the annual average rate on 30-year treasury notes plus 580 basis points. Beginning January 1, 2018, ComEd's allowed ROE is

Table of Contents

subject to a maximum downward or upward adjustment of 200 basis points if ComEd's cumulative persisting annual MWh savings falls short of or exceeds specified percentage benchmarks of its annual incremental savings goal. See Depreciation and amortization expense discussions below and Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. This represents the change in Operating revenues collected under approved rate riders to recover costs incurred for regulatory programs such as ComEd's purchased power administrative costs and energy efficiency and demand response through June 1, 2017 pursuant to FEJA. The riders are designed to provide full and current cost recovery. An equal and offsetting amount has been included in Operating and maintenance expense. See Operating and maintenance expense discussion below for additional information on included programs.

Uncollectible Accounts Recovery, Net. Uncollectible accounts recovery, net represents recoveries under ComEd's uncollectible accounts tariff. See Operating and maintenance expense discussion below for additional information on this tariff.

Other. Other revenue, which can vary period to period, includes rental revenue, revenue related to late payment charges, assistance provided to other utilities through mutual assistance programs, recoveries of environmental costs associated with MGP sites, and recoveries of energy procurement costs. The increase in Other revenue for the three and six months ended June 30, 2018 compared to the same period in 2017 primarily reflects mutual assistance revenues associated with hurricane and winter storm restoration efforts. An equal and offsetting amount has been included in Operating and maintenance expense and Taxes other than income.

Operating and Maintenance Expense

	Three Months Ended June 30,		Increase (Decrease)	Six Months Ended June 30,		Increase (Decrease)
	2018	2017		2018	2017	
Operating and maintenance expense — baseline	$318	$334	$ (16)	$630	$645	$ (15)
Operating and maintenance expense — regulatory required programs[(a)]	6	43	$ (37)	8	102	(94)
Total Operating and maintenance expense	$324	$377	$ (53)	$638	$747	$ (109)

(a) Operating and maintenance expense for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

Table of Contents

The decrease in Operating and maintenance expense for the three and six months ended June 30, 2018 compared to the same period in 2017, consisted of the following:

	Three Months Ended June 30, 2018 Increase (Decrease)	Six Months Ended June 30, 2018 Increase (Decrease)
Baseline		
Labor, other benefits, contracting and materials[a]	$ (11)	$ (1)
Pension and non-pension postretirement benefits expense[a]	(1)	—
Storm-related costs	(10)	(17)
Uncollectible accounts expense — provision[b]	1	4
Uncollectible accounts expense — recovery, net[b]	—	(1)
BSC costs[a]	4	2
Other[a]	1	(2)
	(16)	(15)
Regulatory required programs		
Energy efficiency and demand response programs[c]	(37)	(94)
Decrease in operating and maintenance expense	$ (53)	$ (109)

(a) Includes additional costs associated with mutual assistance programs. An equal and offsetting increase has been recognized in Operating revenues for the period presented.

(b) ComEd is allowed to recover from or refund to customers the difference between the utility's annual uncollectible accounts expense and the amounts collected in rates annually through a rider mechanism. During the three and six months ended June 30, 2018, ComEd recorded a net increase in Operating and maintenance expense related to uncollectible accounts due to the timing of regulatory cost recovery. An equal and offsetting increase has been recognized in Operating revenues for the period presented.

(c) Beginning June 1, 2017, ComEd is deferring energy efficiency costs as a regulatory asset that will be recovered through the energy efficiency formula rate over the weighted average useful life of the related energy efficiency measures.

Depreciation and Amortization Expense

The increase in Depreciation and amortization expense during the three and six months ended June 30, 2018 compared to the same period in 2017, consisted of the following:

	Three Months Ended June 30, 2018 Increase	Six Months Ended June 30, 2018 Increase
Depreciation expense[a]	$ 10	$ 21
Regulatory asset amortization[b]	10	19
Total increase	$ 20	$ 40

(a) Primarily reflects ongoing capital expenditures for the three and six months ended June 30, 2018.

(b) Beginning in June 2017, includes amortization of ComEd's energy efficiency formula rate regulatory asset.

Taxes Other Than Income

Taxes other than income, which can vary year to year, include municipal and state utility taxes, real estate taxes and payroll taxes. Taxes other than income taxes remained relatively consistent for the three and six months ended June 30, 2018 compared to the same period in 2017.

Table of Contents

Gain on Sales of Assets

The increase in Gain on sales of assets during the three and six months ended June 30, 2018 compared to the same period in 2017, is primarily due to the sale of land in March 2018.

Interest Expense, Net

The changes in Interest expense, net, for the three and six months ended June 30, 2018 compared to the same period in 2017 consisted of the following:

	Three Months Ended June 30, 2018 Increase (Decrease)	Six Months Ended June 30, 2018 Increase (Decrease)
Interest expense related to uncertain tax positions[(a)]	$ (14)	$ (14)
Interest expense on debt (including financing trusts)	—	4
Other	(2)	—
Decrease in interest expense, net	$ (16)	$ (10)

(a) Primarily reflects additional interest recorded in the second quarter of 2017 related to Exelon's like-kind exchange tax position.

Other, Net

Other, net, remained relatively consistent for the three and six months ended June 30, 2018 compared to the same period in 2017.

Effective Income Tax Rate

ComEd's effective income tax rate was 20.8% and 46.8% for the three months ended June 30, 2018 and 2017, respectively. ComEd's effective income tax rate was 21.1% and 43.2% for the six months ended June 30, 2018 and 2017, respectively. The decrease in the effective income tax rate for the three and six months ended June 30, 2018 compared to the same period in 2017 is primarily due to the lower federal income tax rate as a result of the TCJA. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Table of Contents

ComEd Electric Operating Statistics Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended June 30, 2018	2017	% Change	Weather-Normal % Change	Six Months Ended June 30, 2018	2017	% Change	Weather-Normal % Change
Retail Deliveries[(a)]								
Residential	6,557	5,919	10.8 %	1.5 %	13,173	12,160	8.3 %	1.2 %
Small commercial & industrial	7,735	7,437	4.0 %	1.7 %	15,578	15,146	2.9 %	0.6 %
Large commercial & industrial	7,111	6,798	4.6 %	3.2 %	13,948	13,480	3.5 %	2.0 %
Public authorities & electric railroads	286	282	1.4 %	1.2 %	646	625	3.4 %	2.1 %
Total retail deliveries	21,689	20,436	6.1 %	2.1 %	43,345	41,411	4.7 %	1.2 %

Number of Electric Customers	As of June 30, 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 volume from customers purchasing electricity directly from ComEd and customers purchasing electricity from a competitive electric generation supplier, as all customers are assessed delivery charges.

See Note 19 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of ComEd's revenue disaggregation.

Table of Contents

Results of Operations — PECO

	Three Months Ended June 30, 2018	2017	Favorable (Unfavorable) Variance	Six Months Ended June 30, 2018	2017	Favorable (Unfavorable) Variance
Operating revenues	$653	$630	$ 23	$1,518	$1,426	$ 92
Purchased power and fuel expense	222	197	(25)	555	484	(71)
Revenues net of purchased power and fuel expense[(a)]	431	433	(2)	963	942	21
Other operating expenses						
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 other operating expenses	304	296	(8)	694	613	(81)
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)

(a) PECO evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. PECO believes revenue net of purchased power expense and revenue net of fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. PECO has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power expense and revenue net of fuel expense figures are not presentations defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income

Three Months Ended June 30, 2018 Compared to Three Months Ended June 30, 2017. PECO's Net income increased from the same period in 2017, primarily due to higher Operating revenues net of purchase power and fuel expense attributable to favorable weather and volume. The TCJA did not significantly impact PECO's Net income for the three and six months ended June 30, 2018 as the favorable income tax impacts were predominantly offset by lower revenues resulting from the requirement to pass back the tax savings through customer rates.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017. PECO's Net income decreased from the same period in 2017, primarily due to higher Operating and maintenance expense attributable to increased storm restoration costs as a result of winter storms in March 2018, partially offset by higher Operating revenues net of purchase power and fuel expense attributable to favorable weather and volume. The TCJA did not significantly impact PECO's Net income for the three and six months ended June 30, 2018 as the favorable income tax impacts were predominantly offset by lower revenues resulting from the requirement to pass back the tax savings through customer rates.

Table of Contents

Revenues Net of Purchased Power and Fuel Expense

Electric and natural gas revenue and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. PECO's electric supply and natural gas cost rates charged to customers are subject to adjustments as specified in the PAPUC-approved tariffs that are designed to recover or refund the difference between the actual cost of electric supply and natural gas and the amount included in rates in accordance with PECO's GSA and PGC, respectively. Therefore, fluctuations in electric supply and natural gas procurement costs have no impact on electric and natural gas revenue net of purchased power and fuel expense.

Electric and natural gas revenue and purchased power and fuel expense are also affected by fluctuations in participation in the Customer Choice Program. All PECO customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers, respectively. The customer's Choice of suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and natural gas service. Customer choice program activity has no impact on electric and natural gas revenues net of purchased power and fuel expense.

Retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of kWh and mmcf sales, respectively) for the three and six months ended June 30, 2018 and 2017, consisted of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Electric	71%	73%	69%	71%
Natural Gas	28%	29%	25%	26%

Retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at June 30, 2018 and 2017 consisted of the following:

	June 30, 2018		June 30, 2017	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	547,800	33 %	581,600	36 %
Natural Gas	85,700	16 %	82,000	16 %

Table of Contents

The changes in PECO’s Operating revenues net of purchased power and fuel expense for the three and six months ended June 30, 2018 compared to the same period in 2017 consisted of the following:

	Three Months Ended June 30, 2018 Increase (Decrease)			Six Months Ended June 30, 2018 Increase (Decrease)		
	Electric	Natural Gas	Total	Electric	Natural Gas	Total
Weather	$2	$ 6	$8	$19	$ 18	$37
Volume	9	—	9	8	3	11
Pricing	(23)	(1)	(24)	(30)	(8)	(38)
Regulatory required programs	—	—	—	(2)	—	(2)
Other	7	(2)	5	16	(3)	13
Total (decrease) increase	$(5)	$ 3	$(2)	$11	$ 10	$21

Weather. The demand for electricity and natural gas is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and natural gas businesses, very cold weather in winter months are referred to as “favorable weather conditions” because these weather conditions result in increased deliveries of electricity and natural gas. Conversely, mild weather reduces demand. During the three and six months ended June 30, 2018 compared to the same period in 2017, Operating revenue net of purchased power and fuel increased due to favorable weather conditions.

Heating and cooling degree-days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree-days for a 30-year period in PECO's service territory. The changes in heating and cooling degree-days in PECO’s service territory for the three and six months ended June 30, 2018 compared to the same period in 2017 and normal weather consisted of the following:

Heating and Cooling Degree-Days				% Change	
Three Months Ended June 30,	2018	2017	Normal	From 2017	2018 vs. 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,					
Heating Degree-Days	2,879	2,423	2,885	18.8 %	(0.2)%
Cooling Degree-Days	382	415	385	(8.0)%	(0.8)%

Volume. Operating revenue net of purchased power related to delivery volume, exclusive of the effects of weather, for the three and six months ended June 30, 2018 compared to the same period in 2017, increased due to the impact of moderate economic and customer growth partially offset by the impact of energy efficiency initiatives on customer usages primarily in the residential class. Additionally, the increase represents a shift in the volume profile across classes from the commercial and industrial classes to the residential class. Operating revenue net of fuel expense for the six months ended June 30, 2018 compared to the same period in 2017 increased due to strong customer growth and moderate economic growth.

Pricing. Operating revenues net of purchased power as a result of pricing for the three and six months ended June 30, 2018 compared to the same period in 2017 decreased primarily due to the pass

Table of Contents

back through customers rates the tax savings associated with the lower federal income tax rate. See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.
Regulatory Required Programs. This represents the change in Operating revenues collected under approved riders to recover costs incurred for regulatory programs such as smart meter, energy efficiency and the GSA. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Income taxes. See Operating and maintenance expense discussion below for additional information on included programs.
Other. Other revenue, which can vary period to period, primarily includes wholesale transmission revenue, rental revenue, revenue related to late payment charges and assistance provided to other utilities through mutual assistance programs.
Operating and Maintenance Expense

	Three Months Ended June 30,		Increase (Decrease)	Six Months Ended June 30,		Increase (Decrease)
	2018	2017		2018	2017	
Operating and maintenance expense — baseline	$175	$174	$ 1	$435	$370	$ 65
Operating and maintenance expense — regulatory required programs[(a)]	16	16	—	31	28	3
Total Operating and maintenance expense	$191	$190	$ 1	$466	$398	$ 68

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

The changes in Operating and maintenance expense for the three and six months ended June 30, 2018 compared to the same period in 2017, consisted of the following:

	Three Months Ended June 30, 2018 Increase (Decrease)	Six Months Ended June 30, 2018 Increase (Decrease)
Baseline		
Labor, other benefits, contracting and materials	$ 7	$ 11
Storm-related costs[(a)]	—	58
Pension and non-pension postretirement benefits expense	(2)	(3)
Other	(4)	(1)
	1	65
Regulatory Required Programs		
Energy efficiency	—	3
Total increase	$ 1	$ 68

(a) Reflects increased costs incurred from the Q1 2018 winter storms.

237

Table of Contents

Depreciation and Amortization Expense
Depreciation and amortization expense increased primarily due to ongoing capital spend for the three and six months ended June 30, 2018 compared to the same period in 2017.
Taxes Other Than Income
Taxes other than income, which can vary period to period, include municipal and state utility taxes, real estate taxes and payroll taxes. Taxes other than income increased for the three and six months ended June 30, 2018 compared to the same period in 2017 due to an increase in gross receipts tax driven by an increase in electric revenue.
Interest Expense, Net
Interest expense, net for the three and six months ended June 30, 2018 remained relatively consistent compared to the same period in 2017.
Other, Net
Other, net for the three and six months ended June 30, 2018 remained consistent compared to the same period in 2017.
Effective Income Tax Rate
PECO's effective income tax rate was (1.1)% and 18.5% for the three months ended June 30, 2018 and 2017, respectively. PECO's effective income tax rate was (1.4)% and 20.4% for the six months ended June 30, 2018 and 2017, respectively. The decrease in the effective income tax rate for the three and six months ended June 30, 2018 compared to the same period in 2017 is primarily due to the lower federal income tax rate as a result of the TCJA. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Table of Contents

PECO Electric Operating Statistics

Retail Deliveries to Customers (in GWhs)	Three Months Ended June 30, 2018	2017	% Change	Weather - Normal % Change	Six Months Ended June 30, 2018	2017	% Change	Weather - Normal % Change
Retail Deliveries[a]								
Residential	2,946	2,809	4.9 %	3.8 %	6,574	6,187	6.3 %	1.7 %
Small commercial & industrial	1,930	1,914	0.8 %	0.4 %	3,958	3,890	1.7 %	(0.4)%
Large commercial & industrial	3,811	3,830	(0.5)%	0.1 %	7,514	7,456	0.8 %	1.1 %
Public authorities & electric railroads	182	196	(7.1)%	(5.6)%	379	420	(9.8)%	(9.1)%
Total retail deliveries	8,869	8,749	1.4 %	1.2 %	18,425	17,953	2.6 %	0.8 %

Number of Electric Customers	As of June 30, 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

(a) Reflects delivery volumes from customers purchasing electricity directly from PECO and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges.

Table of Contents

PECO Natural Gas Operating Statistics

Deliveries to Customers (in mmcf)	Three Months Ended June 30, 2018	2017	% Change	Weather - Normal % Change	Six Months Ended June 30, 2018	2017	% Change	Weather - Normal % Change
Retail Deliveries[a]								
Residential	5,889	4,577	28.7 %	0.9 %	26,463	22,689	16.6 %	0.9 %
Small commercial & industrial	3,598	3,039	18.4 %	0.2 %	14,016	12,130	15.5 %	2.2 %
Large commercial & industrial	6	5	20.0 %	12.8 %	52	13	300.0 %	291.0 %
Transportation	5,981	5,759	3.9 %	3.2 %	13,549	13,448	0.8 %	(3.3)%
Total natural gas deliveries	15,474	13,380	15.7 %	1.6 %	54,080	48,280	12.0 %	0.2 %

Number of Natural Gas Customers	As of June 30, 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 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.

See Note 19 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of PECO's revenue disaggregation.

240

Table of Contents

Results of Operations — BGE

	Three Months Ended June 30, 2018	2017	Favorable (Unfavorable) Variance	Six Months Ended June 30, 2018	2017	Favorable (Unfavorable) Variance
Operating revenues	$662	$674	$ (12)	$1,639	$1,625	$ 14
Purchased power and fuel expense	229	234	5	609	584	(25)
Revenues net of purchased power and fuel expense[(a)]	433	440	(7)	1,030	1,041	(11)
Other operating expenses						
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 other operating expenses	349	342	(7)	769	715	(54)
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) BGE evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. BGE believes revenues net of purchased power and fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. BGE has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenues net of purchased power and fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income

Three Months Ended June 30, 2018 Compared to Three Months Ended June 30, 2017. BGE's Net income for the three months ended June 30, 2018 was higher than the same period in 2017, primarily due to higher transmission revenues. The TCJA did not significantly impact BGE's net income for the three months ended June 30, 2018 as the favorable income tax impacts were predominantly offset by lower revenues resulting from the pass back of the tax savings through customer rates.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017. BGE's Net income for the six months ended June 30, 2018 was higher than the same period in 2017, due primarily to higher transmission revenues, partially offset by an increase in Operating and maintenance expense attributable to increased storm restoration costs as a result of winter storms in March 2018. The TCJA did not significantly impact BGE's net income for the six months ended June 30, 2018 as the favorable income tax impacts were predominantly offset by lower revenues resulting from the pass back of the tax savings through customer rates.

Table of Contents

Revenues Net of Purchased Power and Fuel Expense

There are certain drivers to Operating revenues that are offset by their impact on Purchased power and fuel expense, such as commodity procurement costs and programs allowing customers to select a competitive electric or natural gas supplier. Operating revenues and Purchased power and fuel expense are affected by fluctuations in commodity procurement costs. BGE's electric and natural gas rates charged to customers are subject to periodic adjustments that are designed to recover or refund the difference between the actual cost of purchased electric power and purchased natural gas and the amount included in rates in accordance with the MDPSC's market-based SOS and gas commodity programs, respectively. Therefore, fluctuations in electric supply and natural gas procurement costs have no impact on Revenues net of purchased power and fuel expense.

Electric and natural gas revenue and purchased power and fuel expense are also affected by fluctuations in the number of customers electing to use a competitive supplier for electricity and/or natural gas. All BGE customers have the choice to purchase electricity and natural gas from competitive suppliers. The customers' choice of suppliers does not impact the volume of deliveries but does affect revenue collected from customers related to supplied electricity and natural gas.

Retail deliveries purchased from competitive electricity and natural gas suppliers (as a percentage of kWh and mmcf sales, respectively) for the three and six months ended June 30, 2018 and 2017 consisted of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Electric	61%	62%	59%	60%
Natural Gas	66%	68%	52%	53%

The number of retail customers purchasing electricity and natural gas from competitive suppliers at June 30, 2018 and 2017 consisted of the following:

	June 30, 2018		June 30, 2017	
	Number of Customers	% of total retail customers	Number of customers	% of total retail customers
Electric	337,200	26 %	340,500	27 %
Natural Gas	148,800	22 %	150,400	22 %

Table of Contents

The changes in BGE’s Operating revenues net of purchased power and fuel expense for the three and six months ended June 30, 2018, compared to the same period in 2017, consisted of the following:

	Three Months Ended June 30, 2018			Six Months Ended June 30, 2018		
	Increase (Decrease)			Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Distribution revenue	$(15)	$(3)	$(18)	$(34)	$(17)	$(51)
Regulatory required programs	—	1	1	4	3	7
Transmission revenue	6	—	6	20	—	20
Other, net	1	3	4	3	10	13
Total (decrease) increase	$(8)	$1	$(7)	$(7)	$(4)	$(11)

Revenue Decoupling. The demand for electricity and natural gas is affected by weather and usage conditions. The MDPSC allows BGE to record a monthly adjustment to its electric and natural gas distribution revenue from all residential customers, commercial electric customers, the majority of large industrial electric customers, and all firm service natural gas customers to eliminate the effect of abnormal weather and usage patterns per customer on BGE's electric and natural gas distribution volumes, thereby recovering a specified dollar amount of distribution revenue per customer, by customer class, regardless of fluctuations in actual consumption levels. This allows BGE to recognize revenue at MDPSC-approved distribution charges per customer, regardless of what BGE's actual distribution volumes were for a billing period. Therefore, while this revenue is affected by customer growth (i.e., increase in the number of customers), it will not be affected by volatility in actual weather or usage conditions (i.e., changes in consumption per customer). BGE bills or credits customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

Heating and cooling degree-days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree-days for a 30-year period in BGE's service territory. The changes in heating and cooling degree-days in BGE's service territory for the three and six months ended June 30, 2018 compared to the same period in 2017 consisted of the following:

Heating and Cooling Degree-Days				% Change	
Three Months Ended June 30,	2018	2017	Normal	2018 vs. 2017	2018 vs. 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,					
Heating Degree-Days	2,939	2,460	2,898	19.5%	1.4 %
Cooling Degree-Days	299	283	256	5.7 %	16.8 %

Distribution Revenue. The decrease in distribution revenues for the three and six months ended June 30, 2018, compared to the same period in 2017, was primarily due to the impact of reduced distribution rates to reflect the lower federal income tax rate. See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Table of Contents

Regulatory Required Programs. Revenue from regulatory required programs are billings for the costs of various legislative and/or regulatory programs that are recoverable from customers on a full and current basis. These programs are designed to provide full cost recovery, as well as a return in certain instances. The costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Taxes other than income in BGE's Consolidated Statements of Operations and Comprehensive Income.

Transmission Revenue. Under a FERC approved formula, transmission revenue varies from year to year based upon rate adjustments to reflect fluctuations in the underlying costs, capital investments being recovered and other billing determinants. The increase in transmission revenue for the three and six months ended June 30, 2018, compared to the same period in 2017, was primarily due to increases in capital investment and operating and maintenance expense recoveries. See Operating and Maintenance Expense below and Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Other, Net. Other, net revenue, which can vary from period to period, primarily includes assistance provided to other utilities through BGE's mutual assistance program, off-system sales, and other miscellaneous revenue such as service application fees and late payment fees.

Operating and Maintenance Expense

	Three Months Ended June 30,		Increase (Decrease)	Six Months Ended June 30,		Increase (Decrease)
	2018	2017		2018	2017	
Operating and maintenance expense — baseline	$174	$170	$ 4	$392	$348	$ 44
Operating and maintenance expense — regulatory required programs (a)	2	4	(2)	5	9	(4)
Total Operating and maintenance expense	$176	$174	$ 2	$397	$357	$ 40

(a) Operating and maintenance expense for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

Table of Contents

The changes in Operating and maintenance expense for the three and six months ended June 30, 2018, compared to the same period in 2017, consisted of the following:

	Three Months Ended June 30, 2018 Increase (Decrease)	Six Months Ended June 30, 2018 Increase (Decrease)
Baseline		
Storm-related costs[a]	$ (4)	$ 23
Labor, other benefits, contracting and materials	3	7
Uncollectible accounts expense	(1)	2
BSC costs	3	4
Other	3	8
	4	44
Regulatory Required Programs		
Other	(2)	(4)
Total increase	$ 2	$ 40

(a) Reflects increased storm restoration costs incurred from the Q1 2018 winter storms.

Depreciation and Amortization

The changes in Depreciation and amortization expense for the three and six months ended June 30, 2018, compared to the same period in 2017 consisted of the following:

	Three Months Ended June 30, 2018 Increase (Decrease)	Six Months Ended June 30, 2018 Increase (Decrease)
Depreciation expense[a]	$ 7	$ 9
Regulatory asset amortization[b]	(8)	(11)
Regulatory required programs[c]	3	11
Total increase	$ 2	$ 9

(a) Depreciation expense increased due to ongoing capital expenditures.

(b) Regulatory asset amortization decreased for the three and six months ended June 30, 2018 compared to the same period in 2017 primarily due to certain regulatory assets that became fully amortized as of December 31, 2017. See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

(c) Depreciation and amortization expenses for regulatory required programs are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

Taxes Other Than Income

Taxes other than income, which can vary period to period, include municipal and state utility taxes, real estate taxes and payroll taxes. Taxes other than income for the three and six months ended June 30, 2018, compared to the same period in 2017, increased primarily due to an increase in property taxes.

Gain on Sales of Assets

The increase in Gain on sales of assets during the three and six months ended June 30, 2018, compared to the same period in 2017, is primarily due to the sale of land in June 2018.

Table of Contents

Interest Expense, Net
Interest expense, net for the three and six months ended June 30, 2018, compared to the same period in 2017, remained relatively consistent.
Other, Net
Other, net for the three and six months ended June 30, 2018, compared to the same period in 2017, remained relatively consistent.
Effective Income Tax Rate
BGE's effective income tax rate was 20.3% and 40.8% for the three months ended June 30, 2018 and 2017, respectively. BGE's effective income tax rate was 18.6% and 39.6% for the six months ended June 30, 2018 and 2017, respectively. The decrease in the effective income tax rate for the three and six months ended June 30, 2018, compared to the same periods in 2017, is primarily due to the lower federal income tax rate as a result of the TCJA. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.
BGE Electric Operating Statistics and Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended June 30,		% Change	Weather - Normal % Change	Six Months Ended June 30,		% Change	Weather - Normal % Change
	2018	2017			2018	2017		
Retail Deliveries[a]								
Residential	2,717	2,629	3.3 %	0.9 %	6,297	5,756	9.4 %	2.2 %
Small commercial & industrial	700	677	3.4 %	(3.4)%	1,485	1,425	4.2 %	(0.4)%
Large commercial & industrial	3,396	3,373	0.7 %	(1.9)%	6,752	6,641	1.7 %	(0.7)%
Public authorities & electric railroads	69	72	(4.2)%	(14.2)%	136	140	(2.9)%	(3.1)%
Total electric deliveries	6,882	6,751	1.9 %	(1.1)%	14,670	13,962	5.1 %	0.5 %

Number of Electric Customers	As of June 30, 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

(a) Reflects delivery volumes from customers purchasing electricity directly from BGE and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges.

Table of Contents

BGE Natural Gas Operating Statistics and Detail

Deliveries to Customers (in mmcf)	Three Months Ended June 30, 2018	2017	% Change	Weather - Normal % Change	Six Months Ended June 30, 2018	2017	% Change	Weather - Normal % Change
Retail Deliveries[a]								
Residential	5,271	3,613	45.9 %	15.1 %	27,046	21,730	24.5 %	4.0 %
Small commercial & industrial	1,433	1,075	33.3 %	13.3 %	6,207	4,853	27.9 %	8.2 %
Large commercial & industrial	10,167	8,340	21.9 %	18.2 %	25,817	22,816	13.2 %	7.2 %
Other[b]	2,661	116	2,194.0 %	n/a	8,039	2,395	235.7 %	n/a
Total natural gas deliveries	19,532	13,144	48.6 %	16.9 %	67,109	51,794	29.6 %	5.8 %

Number of Gas Customers	As of June 30, 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 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.

(b) Other natural gas revenue includes off-system sales of 2,661 mmcfs and 116 mmcfs for the three months ended June 30, 2018 and 2017, respectively. Other natural gas revenue includes off-system sales of 8,039 mmcfs and 2,395 mmcfs for the six months ended June 30, 2018 and 2017. respectively.

See Note 19 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of BGE's revenue disaggregation.

247

Table of Contents

Results of Operations — PHI

PHI's results of operations include the results of its three reportable segments, Pepco, DPL and ACE for all periods presented below. All material intercompany accounts and transactions have been eliminated in consolidation. A separate specific discussion of the results of operations for Pepco, DPL and ACE is presented elsewhere in this report.

	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Favorable (Unfavorable) Variance	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017	Favorable (Unfavorable) Variance
Operating revenues	$1,076	$1,074	$ 2	$2,327	$2,248	$ 79
Purchased power and fuel expense	381	383	2	901	845	(56)
Revenues net of purchased power and fuel expense[(a)]	695	691	4	1,426	1,403	23
Other operating expenses						
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 other operating expenses	542	544	2	1,147	1,077	(70)
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)

(a) PHI evaluates its operating performance using the measure of revenue net of purchased power and fuel expense for electric and natural gas sales. PHI believes revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. PHI has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Three Months Ended June 30, 2018 Compared to Three Months Ended June 30, 2017. PHI's Net income for the three months ended June 30, 2018 was $84 million compared to $66 million for the three months ended June 30, 2017.

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed above, increased by $4 million for the three months ended June 30, 2018 compared to the same period in 2017 primarily due to higher utility revenues due to regulatory rate increases at Pepco, DPL and ACE, partially offset by lower revenues resulting from the anticipated pass back of TCJA tax savings through customer rates and lower affiliate revenues at PHISCO as a result of the completion of integration transition activities.

Table of Contents

Operating and maintenance expense decreased by $14 million for the three months ended June 30, 2018 compared to the same period in 2017. The decrease is attributable to the following factors:

- Decrease of $22 million across all companies primarily related to lower uncollectible accounts expense as a result of lower accounts receivable;
- Net decrease of $1 million in labor and contracting expense which is made up of a decrease of $13 million at PHISCO as a result of the completion of integration transition activities, partially offset by an increase of $12 million at Pepco, DPL and ACE.

Depreciation and amortization expense for the three months ended June 30, 2018 compared to the same period in 2017 increased by $15 million due to ongoing capital expenditures as well as higher amortization of regulatory assets as a result of ratemaking activity.

Taxes other than income for the three months ended June 30, 2018 compared to the same period in 2017 remained relatively consistent.

Gain on sales of assets during the three months ended June 30, 2018 compared to the same period in 2017 decreased $1 million due to the sale of land in June 2017.

Interest expense, net for the three months ended June 30, 2018 compared to the same period in 2017 increased by $6 million due to higher outstanding debt.

Other, net for the three months ended June 30, 2018 compared to the same period in 2017 remained relatively consistent.

PHI's effective income tax rate was 15.2% and 35.3% for the three months ended June 30, 2018 and 2017, respectively. The decrease in the effective income tax rate for the three months ended June 30, 2018 compared to the same period in 2017 is primarily due to the lower federal income tax rate as a result of the TCJA. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017. PHI's Net income for the three months ended June 30, 2018 was $149 million compared to $205 million for the three months ended June 30, 2017.

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed above, increased by $23 million for the six months ended June 30, 2018 compared to the same period in 2017 primarily due to higher utility revenues due to regulatory rate increases at Pepco, DPL and ACE, partially offset by lower revenues resulting from the anticipated pass back of TCJA tax savings through customer rates and lower affiliate revenues at PHISCO as a result of the completion of integration transition activities.

Operating and maintenance expense increased by $39 million for the six months ended June 30, 2018 compared to the same period in 2017. The increase is attributable to the following factors:

- Net increase of $11 million in labor and contracting expense which is made up of an increase of $27 million at Pepco, DPL and ACE, partially offset by a decrease of $16 million at PHISCO as a result of the completion of integration transition activities;
- Increase of $8 million at DPL due to deferral of integration costs in 2017;
- Increase of $4 million across all companies primarily related to higher uncollectible accounts expense as a result of higher accounts receivable.

Table of Contents

Depreciation and amortization expense for the six months ended June 30, 2018 compared to the same period in 2017 increased by $31 million due to ongoing capital expenditures as well as higher amortization of regulatory assets as a result of ratemaking activity.
Taxes other than income for the six months ended June 30, 2018 compared to the same period in 2017 remained relatively consistent.
Gain on sales of assets during the six months ended June 30, 2018 compared to the same period in 2017 decreased $1 million due to the sale of land in June 2017.
Interest expense, net for the six months ended June 30, 2018 compared to the same period in 2017 increased $6 million due to higher outstanding debt.
Other, net for the six months ended June 30, 2018 compared to the same period in 2017 remained relatively consistent.
PHI's effective income tax rate was 13.9% and 11.3% for the six months ended June 30, 2018 and 2017, respectively. The increase in the effective income tax rate for the six months ended June 30, 2018 compared to the same periods in 2017 is primarily due to the lower federal income tax rate as a result of the TCJA, partially offset by a nonrecurring adjustment to income tax reserve balances in 2017. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Table of Contents

Results of Operations - Pepco

	Three Months Ended June 30, 2018	2017	Favorable (Unfavorable) Variance	Six Months Ended June 30, 2018	2017	Favorable (Unfavorable) Variance
Operating revenues	$523	$514	$ 9	$1,080	$1,045	$ 35
Purchased power expense	140	143	3	322	309	(13)
Revenues net of purchased power expense[a]	383	371	12	758	736	22
Other operating expenses						
Operating and maintenance	116	120	4	246	234	(12)
Depreciation and amortization	92	78	(14)	188	160	(28)
Taxes other than income	90	90	—	183	180	(3)
Total other operating expenses	298	288	(10)	617	574	(43)
Gain on sales of assets	—	1	(1)	—	1	(1)
Operating income	85	84	1	141	163	(22)
Other income and (deductions)						
Interest expense, net	(32)	(28)	(4)	(63)	(58)	(5)
Other, net	8	7	1	16	15	1
Total other income and (deductions)	(24)	(21)	(3)	(47)	(43)	(4)
Income before income taxes	61	63	(2)	94	120	(26)
Income taxes	7	20	13	9	19	10
Net income	$54	$43	$ 11	$85	$101	$ (16)

(a) Pepco evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales. Pepco believes revenue net of purchased power expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Pepco has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income

Three Months Ended June 30, 2018 Compared to Three Months Ended June 30, 2017. Pepco's Net income for the three months ended June 30, 2018, was higher than the same period in 2017, primarily due to higher electric distribution base rates charged to customers in Maryland that became effective in October 2017 and June 2018 and higher electric distribution base rates charged to customers in the District of Columbia that became effective August 2017 and lower uncollectible accounts expense as a result of lower accounts receivable, partially offset by higher Operating and maintenance expense attributable to an increase in labor and contracting expense and higher Depreciation and amortization expense attributable to ongoing capital expenditures. The TCJA did not significantly impact Pepco's Net income for the three months ended June 30, 2018 as the favorable tax impacts were predominantly offset by lower revenues resulting from the pass back of the tax savings through customer rates.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017. Pepco's Net income for the six months ended June 30, 2018, was lower than the same period in 2017 primarily due to higher Depreciation and amortization expense attributable to ongoing capital expenditures, higher

Table of Contents

Operating and maintenance expense attributable to an increase in labor and contracting expense and higher uncollectible accounts expense as a result of higher accounts receivable, partially offset by higher electric distribution base rates charged to customers in Maryland that became effective in October 2017 and June 2018 and higher electric distribution base rates charged to customers in the District of Columbia that became effective August 2017. The TCJA did not significantly impact Pepco's Net income for the six months ended June 30, 2018 as the favorable tax impacts were predominantly offset by lower revenues resulting from the pass back of the tax savings through customer rates.

Revenues Net of Purchased Power Expense

Operating revenues include revenue from the distribution and supply of electricity to Pepco’s customers within its service territories at regulated rates. Operating revenues also include transmission service revenue that Pepco receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology. Operating revenues also include work and services performed on behalf of customers, including other utilities, which is generally not subject to price regulation. Work and services includes mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Electric revenues and purchased power expense are also affected by fluctuations in participation in the Customer Choice Program. All Pepco customers have the choice to purchase electricity from competitive electric generation suppliers. The customers' choice of supplier does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy service.

Retail deliveries purchased from competitive electric generation suppliers (as a percentage of kWh sales) for the three and six months ended June 30, 2018 compared to the same period in 2017, consisted of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Electric	67%	67%	64%	66%

Retail customers purchasing electric generation from competitive electric generation suppliers at June 30, 2018 and 2017 consisted of the following:

	June 30, 2018		June 30, 2017	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	177,786	20 %	179,736	21 %

Retail deliveries purchased from competitive electric generation suppliers represented 74% and 72% of Pepco’s retail kWh sales to the District of Columbia customers and 61% and 58% of Pepco’s retail kWh sales to Maryland customers for the three and six months ended June 30, 2018, respectively and 74% and 74% of Pepco’s retail kWh sales to the District of Columbia customers and 61% and 60% of Pepco’s retail kWh sales to Maryland customers for the three and six months ended June 30, 2017, respectively.

Table of Contents

The changes in Pepco’s operating revenues net of purchased power expense for the three and six months ended June 30, 2018 compared to the same period in 2017 consisted of the following:

	Three Months Ended June 30, 2018 Increase (Decrease)	Six Months Ended June 30, 2018 Increase (Decrease)
Volume	$ 3	$ 6
Distribution revenue	4	3
Regulatory required programs	5	19
Transmission revenues	(3)	(7)
Other	3	1
Total increase	$ 12	$ 22

Revenue Decoupling. Pepco’s results historically have been seasonal, generally producing higher revenue and income in the warmest and coldest periods of the year. For retail customers of Pepco in Maryland and in the District of Columbia, revenues are not affected by unseasonably warmer or colder weather because a bill stabilization adjustment (BSA) for retail customers was implemented that provides for a fixed distribution charge per customer. The BSA has the effect of decoupling the distribution revenue recognized in a reporting period from the amount of power delivered during the period. As a result, the only factors that will cause distribution revenue from customers in Maryland and the District of Columbia to fluctuate from period to period are changes in the number of customers and changes in the approved distribution charge per customer. Changes in customer usage (due to weather conditions, energy prices, energy efficiency programs or other reasons) from period to period have no impact on reported distribution revenue for customers to whom the BSA applies.

Heating and cooling degree-days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree-days for a 20-year period in Pepco's service territory. The changes in heating and cooling degree-days in Pepco’s service territory for the three and six months ended June 30, 2018 compared to the same periods in 2017 and normal weather consisted of the following:

Heating and Cooling Degree-Days				% Change	
Three Months Ended June 30,	2018	2017	Normal	2018 vs. 2017	2018 vs. 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,					
Heating Degree-Days	2,456	1,955	2,436	25.6%	0.8 %
Cooling Degree-Days	578	550	489	5.1 %	18.2 %

Volume. The increase in operating revenue net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the three and six months ended June 30, 2018 compared to the same periods in 2017, primarily reflects the impact of residential customer growth.

Distribution Revenue. The increase in distribution revenues for the three and six months ended June 30, 2018 compared to the same periods in 2017 was primarily due to higher electric distribution base rates charged to customers in Maryland that became effective in October 2017 and June 2018 and higher electric distribution base rates charged to customers in the District of Columbia that became effective August 2017, partially offset by the impact of reduced distribution rates to reflect the lower

253

Table of Contents

federal income tax rate. See Note 6—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. This represents the change in Operating revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Taxes other than income in Pepco's Consolidated Statements of Operations and Comprehensive Income. See Operating and maintenance expense and Depreciation and amortization expense discussion below for additional information on included programs. Revenue from regulatory required programs increased for the three and six months ended June 30, 2018 compared to the same periods in 2017 due to increases in the Maryland and District of Columbia surcharge rates and sales due to higher volumes, as well as the DC PLUG surcharge which became effective in February 2018.

Transmission Revenues. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, capital investments being recovered, the highest daily peak load and other billing adjustments. The decrease in transmission revenues for the three and six months ended June 30, 2018 compared to the same periods in 2017 is a result of a decrease in network transmission service peak loads.

Other. Other revenue, which can vary period to period, includes rental revenue, revenue related to late payment charges, assistance provided to other utilities through mutual assistance programs, and recoveries of other taxes.

Operating and Maintenance Expense

	Three Months Ended June 30,		Increase (Decrease)	Six Months Ended June 30,		Increase (Decrease)
	2018	2017		2018	2017	
Operating and maintenance expense - baseline	$113	$114	$ (1)	$239	$228	$ 11
Operating and maintenance expense - regulatory required programs[(a)]	3	6	(3)	7	6	1
Total operating and maintenance expense	$116	$120	$ (4)	$246	$234	$ 12

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

Table of Contents

The changes in Operating and maintenance expense for the three and six months ended June 30, 2018 compared to the same periods in 2017, consisted of the following:

	Three Months Ended June 30, 2018 Increase (Decrease)	Six Months Ended June 30, 2018 Increase (Decrease)
Baseline		
Uncollectible accounts expense	(8)	3
Labor and contracting[a]	5	6
Other	2	2
	(1)	11
Regulatory required programs	(3)	1
Total (decrease) increase	$ (4)	$ 12

(a) Includes additional costs associated with mutual assistance programs. An equal and offsetting increase has been recognized in Operating revenues for the period presented.

Depreciation and Amortization Expense

The changes in Depreciation and amortization expense for the three and six months ended June 30, 2018 compared to the same period in 2017, consisted of the following:

	Three Months Ended June 30, 2018 Increase (Decrease)	Six Months Ended June 30, 2018 Increase (Decrease)
Depreciation expense[a]	$ 3	$ 5
Regulatory asset amortization[b]	5	14
Regulatory required programs[c]	6	9
Total increase	$ 14	$ 28

(a) Depreciation expense increased due to ongoing capital expenditures.

(b) Regulatory asset amortization increased due to additional regulatory assets related to rate case activity.

(c) Regulatory required programs increased as a result of higher amortization of the DC PLUG regulatory asset. Depreciation and amortization expenses for regulatory required programs are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues and Operating and maintenance expense.

Taxes Other Than Income

Taxes other than income for the three months ended June 30, 2018 compared to the same period in 2017 remained relatively consistent.

Taxes other than income for the six months ended June 30, 2018 compared to the same period in 2017, increased due to an increase in the utility taxes that are collected and passed through by Pepco (which is substantially offset in Operating revenues).

Gain on Sales of Assets

The decrease in Gain on sales of assets during the three and six months ended June 30, 2018, compared to the same period in 2017, is primarily due to the sale of land in June 2017.

Table of Contents

Interest Expense, Net

Interest expense, net for the three and six months ended June 30, 2018 compared to the same periods in 2017 increased due to higher outstanding debt.

Other, Net

Other, net for the three and six months ended June 30, 2018 compared to the same periods in 2017 remained relatively consistent.

Effective Income Tax Rate

Pepco's effective income tax rate was 11.5% and 31.7% for the three months ended June 30, 2018 and 2017, respectively. The decrease in the effective income tax rate for the three months ended June 30, 2018 compared to the same periods in 2017 is primarily due to the lower federal income tax rate as a result of the TCJA.

Pepco's effective income tax rate was 9.6% and 15.8% for the six months ended June 30, 2018 and 2017, respectively. The decrease in the effective income tax rate for the six months ended June 30, 2018 compared to the same periods in 2017 is primarily due to the lower federal income tax rate as a result of the TCJA, partially offset by a nonrecurring adjustment to income tax reserve balances in 2017.

See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the change in effective income tax rates.

Pepco Electric Operating Statistics and Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended June 30,			Weather - Normal % Change	Six Months Ended June 30,			Weather - Normal % Change
	2018	2017	% Change		2018	2017	% Change	
Retail Deliveries[a]								
Residential	1,799	1,757	2.4 %	(5.6)%	4,082	3,757	8.7 %	(0.6)%
Small commercial & industrial	309	326	(5.2)%	(7.9)%	655	652	0.5 %	(3.0)%
Large commercial & industrial	3,693	3,675	0.5 %	(1.6)%	7,363	7,160	2.8 %	0.8 %
Public authorities & electric railroads	174	172	1.2 %	1.2 %	350	362	(3.3)%	(3.6)%
Total retail deliveries	5,975	5,930	0.8 %	(3.1)%	12,450	11,931	4.4 %	— %

	As of June 30,	
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 from customers purchasing electricity directly from Pepco and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges.

Table of Contents

See Note 19 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of Pepco's revenue disaggregation.

Table of Contents

Results of Operations - DPL

	Three Months Ended June 30,		Favorable (Unfavorable) Variance	Six Months Ended June 30,		Favorable (Unfavorable) Variance
	2018	2017		2018	2017	
Operating revenues	$289	$282	$ 7	$673	$644	$ 29
Purchased power and fuel expense	114	113	(1)	291	270	(21)
Revenues net of purchased power and fuel expense[(a)]	175	169	6	382	374	8
Other operating expenses						
Operating and maintenance	77	74	(3)	175	148	(27)
Depreciation and amortization	43	40	(3)	88	79	(9)
Taxes other than income	13	14	1	28	28	—
Total other operating expenses	133	128	(5)	291	255	(36)
Operating income	42	41	1	91	119	(28)
Other income and (deductions)						
Interest expense, net	(14)	(13)	(1)	(27)	(25)	(2)
Other, net	3	3	—	5	6	(1)
Total other income and (deductions)	(11)	(10)	(1)	(22)	(19)	(3)
Income before income taxes	31	31	—	69	100	(31)
Income taxes	5	12	7	12	24	12
Net income	$26	$19	$ 7	$57	$76	$ (19)

(a) DPL evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales and revenue net of fuel expense for natural gas sales. DPL believes revenue net of purchased power expense and revenue net of fuel expense are useful measurements because they provide information that can be used to evaluate its operational performance. DPL has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense and Revenue net of fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income

Three Months Ended June 30, 2018 Compared to Three Months Ended June 30, 2017. DPL's Net income for the three months ended June 30, 2018, was higher than the same period in 2017 primarily due to higher Revenues net of purchased power and fuel expense attributable to higher electric interim distribution base rates charged to customers in Delaware that were put into effect in March 2018 and a decrease in uncollectible accounts expense as a result of lower accounts receivable, partially offset by higher labor and contracting expense and higher regulatory asset amortization due to additional regulatory assets related to rate case activity. The TCJA did not significantly impact DPL's Net income for the three months ended June 30, 2018 as the favorable tax impacts were predominantly offset by lower revenues resulting from the pass back of the tax savings through customer rates.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017. DPL's Net income for the six months ended June 30, 2018, was lower than the same period in 2017 primarily due to higher Operating and maintenance expense attributable to higher labor and contracting expense, a deferral of integration costs in 2017 and higher regulatory asset amortization due to additional regulatory assets related to rate case activity, partially offset by higher electric interim distribution base rates charged to customers in Delaware that were put into effect in March 2018. The TCJA did not significantly impact

Table of Contents

DPL's Net income for the six months ended June 30, 2018 as the favorable tax impacts were predominantly offset by lower revenues resulting from the pass back of the tax savings through customer rates.

Revenues Net of Purchased Power and Fuel Expense

Operating revenues include revenue from the distribution and supply of electricity and natural gas to DPL’s customers within its service territories at regulated rates. Operating revenues also include transmission service revenue that DPL receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology. Operating revenues also include work and services performed on behalf of customers, including other utilities, which is generally not subject to price regulation. Work and services includes mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Natural gas operating revenue includes sources that are subject to price regulation (Regulated Gas Revenue) and those that generally are not subject to price regulation (Other Gas Revenue). Regulated gas revenue includes the revenue DPL receives from on-system natural gas delivered sales and the transportation of natural gas for customers within its service territory at regulated rates. Other gas revenue consists of off-system natural gas sales and the short-term release of interstate pipeline transportation and storage capacity not needed to serve customers. Off-system sales are made possible when low demand for natural gas by regulated customers creates excess pipeline capacity.

Electric and natural gas revenues and purchased power and fuel expense are also affected by fluctuations in participation in the Customer Choice Program. All DPL customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers, respectively. The customers' choice of suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and natural gas service.

Retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of kWh and mmcf sales, respectively) for the three and six months ended June 30, 2018 and 2017, consisted of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Electric	54%	55%	50%	52%
Natural Gas	41%	44%	29%	31%

Retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at June 30, 2018 and 2017 consisted of the following:

	June 30, 2018		June 30, 2017	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	73,908	14.1 %	79,620	15.3 %
Natural Gas	154	0.1 %	155	0.1 %

Retail deliveries purchased from competitive electric generation suppliers represented 56% and 52% of DPL’s retail kWh sales to Delaware customers and 49% and 45% of DPL's retail kWh sales to Maryland customers for the three and six months ended June 30, 2018, respectively and 57% and 55% of DPL's retail kWh sales to Delaware customers and 51% and 48% of DPL's retail kWh sales to Maryland customers for the three and six months ended June 30, 2017, respectively.

Table of Contents

The changes in DPL’s Operating revenues net of purchased power and fuel expense for the three and six months ended June 30, 2018 compared to the same period in 2017 consisted of the following:

	Three Months Ended June 30, 2018 Increase (Decrease)			Six Months Ended June 30, 2018 Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Weather	$2	$(3)	$(1)	$6	$4	$10
Volume	2	3	5	4	1	5
Distribution revenue	(2)	3	1	(10)	(2)	(12)
Regulatory required programs	(1)	—	(1)	(1)	—	(1)
Transmission revenues	1	—	1	2	—	2
Other	1	—	1	4	—	4
Total increase	$3	$3	$6	$5	$3	$8

Revenue Decoupling. DPL’s results historically have been seasonal, generally producing higher revenue and income in the warmest and coldest periods of the year. For retail customers of DPL in Maryland, revenues are not affected by unseasonably warmer or colder weather because a bill stabilization adjustment (BSA) for retail customers was implemented that provides for a fixed distribution charge per customer. The BSA has the effect of decoupling the distribution revenue recognized in a reporting period from the amount of power delivered during the period. As a result, the only factors that will cause distribution revenue from customers in Maryland to fluctuate from period to period are changes in the number of customers and changes in the approved distribution charge per customer. A modified fixed variable rate design, which would provide for a charge not tied to a customer’s volumetric consumption of electricity or natural gas, has been proposed for DPL electricity and natural gas customers in Delaware. Changes in customer usage (due to weather conditions, energy prices, energy efficiency programs or other reasons) from period to period have no impact on reported distribution revenue for customers to whom the BSA applies.

Weather. The demand for electricity and natural gas in areas not subject to the BSA is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and natural gas businesses, very cold weather in winter months are referred to as “favorable weather conditions” because these weather conditions result in increased deliveries of electricity and natural gas. Conversely, mild weather reduces demand. During the three months ended June 30, 2018 compared to the same period in 2017, Operating revenue net of purchased power and fuel expense related to weather remained relatively consistent. During the six months ended June 30, 2018 compared to the same period in 2017, Operating revenue net of purchased power and fuel expense related to weather was higher due to the impact of favorable weather conditions in DPL's Delaware service territory.

Table of Contents

Heating and cooling degree-days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree-days for a 20-year period in DPL's electric service territory and a 30-year period in DPL's natural gas service territory. The changes in heating and cooling degree-days in DPL’s service territory for the three and six months ended June 30, 2018 compared to the same period in 2017 and normal weather consisted of the following:

Electric Service Territory				% Change	
Three Months Ended June 30,	2018	2017	Normal	2018 vs. 2017	2018 vs. Normal
Heating Degree-Days	460	358	468	28.5%	(1.7)%
Cooling Degree-Days	372	361	334	3.0 %	11.4 %
Six Months Ended June 30,					
Heating Degree-Days	2,875	2,452	2,875	17.3%	— %
Cooling Degree-Days	373	361	336	3.3 %	11.0 %

Natural Gas Service Territory				% Change	
Three Months Ended June 30,	2018	2017	Normal	2018 vs. 2017	2018 vs. Normal
Heating Degree-Days	481	372	498	29.3%	(3.4)%
Six Months Ended June 30,					
Heating Degree-Days	2,985	2,543	3,000	17.4%	(0.5)%

Volume. The increase in Operating revenue net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the three and six months ended June 30, 2018 compared to the same period in 2017, primarily reflects the impact of increased average residential and commercial customer usage and growth.

Distribution Revenue. The decrease in electric distribution revenue for the three months ended June 30, 2018, and electric and gas distribution revenue for the six months ended June 30, 2018 compared to the same periods in 2017 was primarily due to reduced electric and gas interim distribution rates in Delaware that were put into effect in March 2018 which reflect the impact of the lower federal income tax rate. The increase in gas distribution revenue for the three months ended June 30, 2018 compared to the same period in 2017 is primarily due to customer sales mix, partially offset by reduced gas interim distribution rates in Delaware that were put into effect in March 2018. See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. This represents the change in Operating revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Taxes other than income in DPL's Consolidated Statements of Operations and Comprehensive Income. See Operating and maintenance expense and Depreciation and amortization expense discussion below for additional information on included programs.

Transmission Revenues. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, capital investments being recovered, the highest daily peak load and other billing adjustments. The transmission revenues for the three and six months ended June 30, 2018 compared to the same period in 2017 remained relatively consistent.

Table of Contents

Other. Other revenue, which can vary period to period, includes rental revenue, revenue related to late payment charges, assistance provided to other utilities through mutual assistance programs, and recoveries of other taxes.

Operating and Maintenance Expense

	Three Months Ended June 30, 2018	2017	Increase (Decrease)	Six Months Ended June 30, 2018	2017	Increase (Decrease)
Operating and maintenance expense - baseline	$75	$70	$ 5	$167	$142	$ 25
Operating and maintenance expense - regulatory required programs[a]	2	4	(2)	8	6	2
Total operating and maintenance expense	$77	$74	$ 3	$175	$148	$ 27

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

The changes in Operating and maintenance expense for the three and six months ended June 30, 2018 compared to the same period in 2017, consisted of the following:

	Three Months Ended June 30, 2018 Increase (Decrease)	Six Months Ended June 30, 2018 Increase (Decrease)
Baseline		
Labor and contracting[a]	$ 6	$ 10
Uncollectible accounts expense	(6)	2
Merger commitments[b]	—	8
Other	5	5
	5	25
Regulatory required programs	(2)	2
Total increase	$ 3	$ 27

(a) Includes additional costs associated with mutual assistance programs. An equal and offsetting increase has been recognized in Operating revenues for the period presented.

(b) Reflects deferral of integration costs in 2017.

Table of Contents

Depreciation and Amortization Expense

The changes in Depreciation and amortization expense for the three and six months ended June 30, 2018 compared to the same period in 2017 consisted of the following:

	Three Months Ended June 30, 2018 Increase (Decrease)	Six Months Ended June 30, 2018 Increase (Decrease)
Depreciation expense[(a)]	$ 1	$ 3
Regulatory asset amortization[(b)]	3	7
Regulatory required programs[(c)]	(1)	(1)
Total increase	$ 3	$ 9

(a) Depreciation expense increased due to ongoing capital expenditures.
(b) Regulatory asset amortization increased due to additional regulatory assets related to rate case activity.
(c) Depreciation and amortization expenses for regulatory required programs are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues and Operating and maintenance expense.

Taxes Other Than Income

Taxes other than income for the three and six months ended June 30, 2018 compared to the same period in 2017 remained relatively consistent.

Interest Expense, Net

Interest expense, net for the three and six months ended June 30, 2018 compared to the same period in 2017 remained relatively consistent.

Other, Net

Other, net for the three and six months ended June 30, 2018 compared to the same period in 2017 remained relatively consistent.

Effective Income Tax Rate

DPL's effective income tax rate was 16.1% and 38.7% for the three months ended June 30, 2018 and 2017, respectively. The decrease in the effective income tax rate for the three months ended June 30, 2018 compared to the same period in 2017 is primarily due to the lower federal income tax rate as a result of the TCJA.

DPL's effective income tax rate was 17.4% and 24.0% for the six months ended June 30, 2018 and 2017, respectively. The decrease in the effective income tax rate for the six months ended June 30, 2018 compared to the same period in 2017 is primarily due to the lower federal income tax rate as a result of the TCJA, partially offset by a nonrecurring adjustment to income tax reserve balances in 2017.

See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Table of Contents

DPL Electric Operating Statistics and Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended June 30, 2018	2017	% Change	Weather - Normal % Change	Six Months Ended June 30, 2018	2017	% Change	Weather - Normal % Change
Retail Deliveries[a]								
Residential	1,115	1,045	6.7 %	2.1 %	2,666	2,404	10.9 %	2.9 %
Small commercial & industrial	536	526	1.9 %	0.8 %	1,105	1,057	4.5 %	2.3 %
Large commercial & industrial	1,187	1,131	5.0 %	4.0 %	2,266	2,195	3.2 %	1.9 %
Public authorities & electric railroads	10	12	(16.7)%	(16.7)%	22	25	(12.0)%	(12.0)%
Total retail deliveries	2,848	2,714	4.9 %	2.6 %	6,059	5,681	6.7 %	2.4 %

Number of Electric Customers	As of June 30, 2018	2017
Residential	461,596	458,361
Small commercial & industrial	61,189	60,499
Large commercial & industrial	1,362	1,410
Public authorities & electric railroads	624	636
Total	524,771	520,906

(a) Reflects delivery volumes from customers purchasing electricity directly from DPL and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges.

DPL Natural Gas Operating Statistics and Detail

Retail Deliveries to Customers (in mmcf)	Three Months Ended June 30, 2018	2017	% Change	Weather - Normal % Change	Six Months Ended June 30, 2018	2017	% Change	Weather - Normal % Change
Retail Deliveries[a]								
Residential	957	713	34.2 %	5.6 %	5,442	4,453	22.2 %	4.0 %
Small commercial & industrial	644	513	25.5 %	5.8 %	2,521	2,197	14.7 %	(2.4)%
Large commercial & industrial	466	453	2.9 %	2.9 %	984	960	2.5 %	2.5 %
Transportation	1,420	1,324	7.3 %	4.9 %	3,633	3,493	4.0 %	0.6 %
Total natural gas deliveries	3,487	3,003	16.1 %	5.0 %	12,580	11,103	13.3 %	1.5 %

Table of Contents

	As of June 30,	
Number of Gas Customers	2018	2017
Residential	122,754	121,166
Small commercial & industrial	9,810	9,725
Large commercial & industrial	18	18
Transportation	154	155
Total	132,736	131,064

____

(a) Reflects delivery volumes 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.

See Note 19 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of DPL's revenue disaggregation.

Table of Contents

Results of Operations - ACE

	Three Months Ended June 30, 2018	2017	Favorable (Unfavorable) Variance	Six Months Ended June 30, 2018	2017	Favorable (Unfavorable) Variance
Operating revenues	$265	$270	$ (5)	$575	$544	$ 31
Purchased power expense	128	128	—	289	266	(23)
Revenues net of purchased power expense[(a)]	137	142	(5)	286	278	8
Other operating expenses						
Operating and maintenance	75	78	3	165	152	(13)
Depreciation and amortization	36	37	1	69	72	3
Taxes other than income	1	2	1	3	4	1
Total other operating expenses	112	117	5	237	228	(9)
Operating income	25	25	—	49	50	(1)
Other income and (deductions)						
Interest expense, net	(16)	(15)	(1)	(32)	(30)	(2)
Other, net	1	2	(1)	1	4	(3)
Total other income and (deductions)	(15)	(13)	(2)	(31)	(26)	(5)
Income before income taxes	10	12	(2)	18	24	(6)
Income taxes	2	4	2	3	(12)	(15)
Net income	$8	$8	$ —	$15	$36	$ (21)

(a) ACE evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales. ACE believes Revenue net of purchased power expense is a useful measurement of its performance because it provides information that can be used to evaluate its operational performance. ACE has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income

Three Months Ended June 30, 2018 Compared to Three Months Ended June 30, 2017. ACE's Net income for the three months ended June 30, 2018, remained unchanged from the same period in 2017, primarily due to higher electric distribution base rates charged to customers in New Jersey that became effective in October 2017 and lower uncollectible accounts expense as a result of lower accounts receivable, primarily offset by higher Operating and maintenance expense attributable to higher labor and contracting expense and higher Depreciation and amortization expense attributable to ongoing capital expenditures. The TCJA did not significantly impact ACE's Net income for the three months ended June 30, 2018 as the favorable income tax impacts were predominately offset by lower revenues resulting from the pass back of the tax savings through customer rates.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017. ACE's Net income for the six months ended June 30, 2018, was lower than the same period in 2017, primarily due to higher Operating and maintenance expense attributable to higher labor and contracting expense and higher Depreciation and amortization expense attributable to ongoing capital expenditures, partially offset by higher electric distribution base rates charged to customers in New Jersey that became effective in October 2017. The TCJA did not significantly impact ACE's Net income for the six months ended June

Table of Contents

30, 2018 as the favorable income tax impacts were predominately offset by lower revenues resulting from the pass back of the tax savings through customer rates.

Revenues Net of Purchased Power Expense

Operating revenues include revenue from the distribution and supply of electricity to ACE's customers within its service territories at regulated rates. Operating revenues also include transmission service revenue that ACE receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology. Operating revenues also include revenue from Transition Bond Charges that ACE receives, and pays to ACE Funding, to fund the principal and interest payments on Transition Bonds, revenue from the resale in the PJM wholesale markets for energy and capacity purchased under contacts with unaffiliated NUGs, and revenue from transmission enhancement credits. Operating revenues also include work and services performed on behalf of customers, including other utilities, which is generally not subject to price regulation. Work and services includes mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Electric revenues and purchased power expense are also affected by fluctuations in participation in the Customer Choice Program. All ACE customers have the choice to purchase electricity from competitive electric generation suppliers. The customer's choice of supplier does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy service.

Retail deliveries purchased from competitive electric generation suppliers (as a percentage of kWh sales) for the three and six months ended June 30, 2018 compared to the same period in 2017 consisted of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Electric	50%	51%	48%	50%

Retail customers purchasing electric generation from competitive electric generation suppliers at June 30, 2018 and 2017 consisted of the following:

	June 30, 2018		June 30, 2017	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	84,629	15 %	92,895	17 %

267

Table of Contents

The changes in ACE’s operating revenue net of purchased power expense for the three and six months ended June 30, 2018 compared to the same period in 2017 consisted of the following:

	Three Months Ended June 30, 2018 Increase (Decrease)	Six Months Ended June 30, 2018 Increase (Decrease)
Weather	$ 2	$ 5
Volume	(1)	6
Distribution revenue	6	9
Regulatory required programs	(13)	(14)
Transmission revenues	1	—
Other	—	2
Total (decrease) increase	$ (5)	$ 8

Weather. The demand for electricity is affected by weather conditions. With respect to the electric business, very warm weather in summer months and very cold weather in winter months are referred to as “favorable weather conditions” because these weather conditions result in increased deliveries of electricity. Conversely, mild weather reduces demand. During the three and six months ended June 30, 2018 compared to the same period in 2017, operating revenue net of purchased power and fuel expense related to weather was higher due to the impact of favorable weather conditions in ACE's service territory.

For retail customers of ACE, distribution revenues are not decoupled from the distribution of electricity by ACE, and thus are subject to variability due to changes in customer consumption. Therefore, changes in customer usage (due to weather conditions, energy prices, energy savings programs or other reasons) from period to period have a direct impact on reported distribution revenue for customers in ACE's service territory.

Heating and cooling degree-days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree-days for a 20-year period in ACE’s service territory. The changes in heating and cooling degree-days in ACE’s service territory for the three and six months ended June 30, 2018 compared to the same period in 2017 consisted of the following:

Heating and Cooling Degree-Days				% Change	
Three Months Ended June 30,	2018	2017	Normal	2018 vs. 2017	2018 vs. 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,					
Heating Degree-Days	2,927	2,585	3,028	13.2 %	(3.3)%
Cooling Degree-Days	354	324	293	9.3 %	20.8 %

Volume. During the three months ended June 30, 2018 compared to the same period in 2017 the operating revenue net of purchased power expense related to delivery volume, exclusive of the effects of weather, was relatively consistent. During the six months ended June 30, 2018 compared to the same period in 2017 the decrease in operating revenue net of purchased power expense related to delivery volume, exclusive of the effects of weather, is primarily due to higher average residential and commercial usage.

Table of Contents

Distribution Revenue. The increase in distribution revenue for the three and six months ended June 30, 2018 compared to the same period in 2017 was primarily due to higher electric distribution base rates charged to customers that became effective in October 2017, partially offset by the impact of reduced distribution rates to reflect the lower federal income tax rate. See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. This represents the change in operating revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Taxes other than income in ACE's Consolidated Statements of Operations and Comprehensive Income. See Operating and maintenance expense and Depreciation and amortization expense discussion below for additional information on included programs. Revenue from regulatory required programs decreased for the three and six months ended June 30, 2018 compared to the same periods in 2017 due to a rate decrease effective October 2017 for the ACE Transition Bonds.

Transmission Revenues. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, capital investments being recovered, the highest daily peak load and other billing adjustments. The transmission revenue net of purchased power expense for the three and six months ended June 30, 2018 compared to the same periods in 2017 remained relatively consistent.

Other. Other revenue, which can vary period to period, includes rental revenue, revenue related to late payment charges, assistance provided to other utilities through mutual assistance programs, and recoveries of other taxes.

Operating and Maintenance Expense

	Three Months Ended June 30, 2018	2017	Increase (Decrease)	Six Months Ended June 30, 2018	2017	Increase (Decrease)
Operating and maintenance expense - baseline	$68	$ 70	$ (2)	$151	$136	$ 15
Operating and maintenance expense - regulatory required programs[(a)]	7	8	(1)	14	16	(2)
Total operating and maintenance expense	$75	$ 78	$ (3)	$165	$152	$ 13

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

269

Table of Contents

The changes in Operating and maintenance expense for the three and six months ended June 30, 2018 compared to the same period in 2017 consisted of the following:

	Three Months Ended June 30, 2018 Increase (Decrease)	Six Months Ended June 30, 2018 Increase (Decrease)
Baseline		
Labor and contracting[(a)]	$ 1	$ 11
Uncollectible accounts expense	(7)	(1)
Other	4	5
	(2)	15
Regulatory required programs	(1)	(2)
Total increase	$ (3)	$ 13

(a) Includes additional costs associated with mutual assistance programs. An equal and offsetting increase has been recognized in Operating revenues for the period presented.

Depreciation and Amortization Expense

The changes in Depreciation and amortization expense for the three and six months ended June 30, 2018 compared to the same period in 2017 consisted of the following:

	Three Months Ended June 30, 2018 Increase (Decrease)	Six Months Ended June 30, 2018 Increase (Decrease)
Depreciation expense[(a)]	$ 1	$ 3
Regulatory asset amortization	3	3
Regulatory required programs[(b)]	(5)	(9)
Total decrease	$ (1)	$ (3)

(a) Depreciation expense increased due to ongoing capital expenditures.

(b) Regulatory required programs decreased as a result of lower revenue due to rate decreases effective October 2017 for the ACE Transition Bonds. Depreciation and amortization expenses for regulatory required programs are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues and Operating and maintenance expense.

Taxes Other Than Income

Taxes other than income for the three and six months ended June 30, 2018 compared to the same period in 2017 remained relatively consistent.

Interest Expense, Net

Interest expense, net for the three and six months ended June 30, 2018 compared to the same period in 2017 remained relatively consistent.

Other, Net

Other, net for the three and six months ended June 30, 2018 compared to the same period in 2017 remained relatively consistent.

Table of Contents

Effective Income Tax Rate
ACE's effective income tax rate was 20.0% and 33.3% for the three months ended June 30, 2018 and 2017, respectively. The decrease in the effective income tax rate for the three months ended June 30, 2018 compared to the same period in 2017 is primarily due to the lower federal income tax rate as a result of the TCJA.
ACE's effective income tax rate was 16.7% and (50.0)% for the six months ended June 30, 2018 and 2017, respectively. The increase in the effective income tax rate for the six months ended June 30, 2018 compared to the same period in 2017 is primarily due to the absence of an unrecognized tax benefit from 2017, partially offset by a nonrecurring adjustment to income tax reserve balances in 2017.
See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.
ACE Electric Operating Statistics and Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended June 30, 2018	2017	% Change	Weather - Normal % Change	Six Months Ended June 30, 2018	2017	% Change	Weather - Normal % Change
Retail Deliveries[(a)]								
Residential	825	814	1.4 %	(2.2)%	1,815	1,693	7.2 %	2.9 %
Small commercial & industrial	309	302	2.3 %	0.3 %	623	585	6.5 %	4.6 %
Large commercial & industrial	872	853	2.2 %	1.4 %	1,696	1,618	4.8 %	4.0 %
Public authorities & electric railroads	11	11	— %	— %	26	24	8.3 %	8.3 %
Total retail deliveries	2,017	1,980	1.9 %	(0.3)%	4,160	3,920	6.1 %	3.6 %

Number of Electric Customers	As of June 30, 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 from customers purchasing electricity directly from ACE and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges.
See Note 19 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of ACE's revenue disaggregation.

Table of Contents

Liquidity and Capital Resources

All results included throughout the liquidity and capital resources section are presented on a GAAP basis.

The Registrants' operating and capital expenditures requirements are provided by internally generated cash flows from operations as well as funds from external sources in the capital markets and through bank borrowings. The Registrants' businesses are capital intensive and require considerable capital resources. Each Registrant's access to external financing on reasonable terms depends on its credit ratings and current overall capital market business conditions, including that of the utility industry in general. If these conditions deteriorate to the extent that the Registrants no longer have access to the capital markets at reasonable terms, the Registrants have access to unsecured revolving credit facilities with aggregate bank commitments of $9 billion. In addition, Generation has $545 million in bilateral facilities with banks which have various expirations between January 2019 and December 2019. The Registrants utilize their credit facilities to support their commercial paper programs, provide for other short-term borrowings and to issue letters of credit. See the "Credit Matters" section below for additional information. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

The Registrants primarily use their capital resources, including cash, to fund capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. The Registrants spend a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. Additionally, ComEd, PECO, BGE, Pepco, DPL and ACE operate in rate-regulated environments in which the amount of new investment recovery may be delayed or limited and where such recovery takes place over an extended period of time. See Note 11 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information of the Registrants' debt and credit agreements.

NRC Minimum Funding Requirements

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that sufficient funds will be available in certain minimum amounts to decommission the facility. These NRC minimum funding levels are based upon the assumption that decommissioning activities will commence after the end of the current licensed life of each unit. If a unit fails the NRC minimum funding test, then the plant's owners or parent companies would be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional cash contributions to the NDT fund to ensure sufficient funds are available. See Note 13 — Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for additional information on the NRC minimum funding requirements.

If a nuclear plant were to early retire there is a risk that it will no longer meet the NRC minimum funding requirements due to the earlier commencement of decommissioning activities and a shorter time period over which the NDT fund investments could appreciate in value. A shortfall could require that Generation address the shortfall by, among other things, obtaining a parental guarantee for Generation's share of the funding assurance. However, the amount of any guarantees or other assurance will ultimately depend on the decommissioning approach, the associated level of costs, and the decommissioning trust fund investment performance going forward. Within two years after shutting down a plant, Generation must submit a post-shutdown decommissioning activities report (PSDAR) to the NRC that includes the planned option for decommissioning the site. As discussed in Note 13 — Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements, Generation filed its annual decommissioning funding status report with the NRC on March 28, 2018 for shutdown reactors and reactors within five years of shut down. As of June 30, 2018, across the alternative decommissioning

Table of Contents

approaches available, Exelon would not be required to post a parental guarantee for TMI or Oyster Creek. In the event PSEG decides to early retire Salem, Generation estimates a parental guarantee of up to $55 million from Exelon could be required for Salem, dependent upon the ultimate decommissioning approach selected.

Upon issuance of any required financial guarantees, each site would be able to utilize the respective NDT funds for radiological decommissioning costs, which represent the majority of the total expected decommissioning costs. However, the NRC must approve an additional exemption in order for the plant's owner(s) to utilize the NDT fund to pay for non-radiological decommissioning costs (i.e., spent fuel management and site restoration costs). If a unit does not receive this exemption, the costs would be borne by the owner(s). While the ultimate amounts may vary greatly and could be reduced by alternate decommissioning scenarios and/or reimbursement of certain costs under the DOE reimbursement agreements or future litigation, across the four alternative decommissioning approaches available, if TMI or Oyster Creek were to fail to obtain the exemption, Generation estimates it could incur spent fuel management and site restoration costs over the next ten years of up to $195 million and $210 million net of taxes, respectively, dependent upon the ultimate decommissioning approach selected. In the event PSEG decides to early retire Salem and Salem were to fail to obtain the exemption, Generation estimates it could incur spent fuel management and site restoration costs over the next ten years of up to $95 million net of taxes.

Cash Flows from Operating Activities

General

Generation's cash flows from operating activities primarily result from the sale of electric energy and energy-related products and services to customers. Generation's future cash flows from operating activities may be affected by future demand for and market prices of energy and its ability to continue to produce and supply power at competitive costs as well as to obtain collections from customers.

The Utility Registrants' cash flows from operating activities primarily result from the transmission and distribution of electricity and, in the case of PECO, BGE and DPL, gas distribution services. The Utility Registrants' distribution services are provided to an established and diverse base of retail customers. The Utility Registrants' future cash flows may be affected by the economy, weather conditions, future legislative initiatives, future regulatory proceedings with respect to their rates or operations, competitive suppliers, and their ability to achieve operating cost reductions.

See Notes 3 — Regulatory Matters and 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements of the Exelon 2017 Form 10-K for additional information of regulatory and legal proceedings and proposed legislation.

Table of Contents

The following table provides a summary of the major items affecting Exelon's cash flows from operations for the six months ended June 30, 2018 and 2017:

	Six Months Ended June 30, 2018	2017	Variance
Net income	$ 1,179	$ 1,066	$ 113
Add (subtract):			
Non-cash operating activities[(a)]	3,689	3,279	410
Pension and non-pension postretirement benefit contributions	(345)	(325)	(20)
Income taxes	129	58	71
Changes in working capital and other noncurrent assets and liabilities[(b)]	(828)	(1,002)	174
Option premiums received (paid), net	(36)	(8)	(28)
Collateral (posted) received, net	81	(173)	254
Net cash flows provided by operations	$ 3,869	$ 2,895	$ 974

(a) Represents depreciation, amortization and accretion, net fair value changes related to derivatives, deferred income taxes, provision for uncollectible accounts, pension and other postretirement benefit expense, equity in earnings and losses of unconsolidated affiliates and investments, decommissioning-related items, stock compensation expense, impairment of long-lived assets, gain on sale of assets and businesses and other non-cash charges. See Note 18 — Supplemental Financial Information of the Combined Notes to Consolidated Financial Statements for additional information on non-cash operating activity.

(b) Changes in working capital and other noncurrent assets and liabilities exclude the changes in commercial paper, income taxes and the current portion of long-term debt.

Pension and Other Postretirement Benefits

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006 (the Act), management of the pension obligation and regulatory implications. The Act requires the attainment of certain funding levels to avoid benefit restrictions (such as an inability to pay lump sums or to accrue benefits prospectively), and at-risk status (which triggers higher minimum contribution requirements and participant notification). Exelon's funding strategy for its qualified pension plans is to contribute the greater of (1) $300 million (inclusive of PHI) and (2) the minimum amounts under ERISA to avoid benefit restrictions and at-risk status. This level funding strategy helps minimize volatility of future period required pension contributions. Unlike the qualified pension plans, Exelon's non-qualified pension plans are not funded given that they are not subject to statutory minimum contribution requirements.

While other postretirement plans are plans are also not subject to statutory minimum contribution requirements, Exelon does fund certain of its plans. For Exelon's funded OPEB plans, contributions generally equal accounting costs, however, Exelon's management has historically considered several factors in determining the level of contributions to its other postretirement benefit plans, including liabilities management, levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulatory expectations and best assure continued rate recovery).

To the extent interest rates decline significantly or the pension and OPEB plans earn less than the expected asset returns, annual pension contribution requirements in future years could increase. Conversely, to the extent interest rates increase significantly or the pension and OPEB plans earn greater than the expected asset returns, annual pension and OPEB contribution requirements in future years could decrease. Additionally, expected contributions could change if Exelon changes its pension or OPEB funding strategy.

Table of Contents

On October 3, 2017, the U.S. Department of Treasury and IRS released final regulations updating the mortality tables to be used for defined benefit pension plan funding, as well as the valuation of lump sum and other accelerated distribution options, effective for plan years beginning in 2018. The new mortality tables reflect improved projected life expectancy as compared to the existing table, which is generally expected to increase minimum pension funding requirements, Pension Benefit Guaranty Corporation premiums and the value of lump sum distributions. The IRS permits plan sponsors the option of delaying use of the new mortality tables for determining minimum funding requirements until 2019, which Exelon has utilized. The one-year delay does not apply for use of the mortality tables to determine the present value of lump sum distributions.

Tax Matters

The Registrants' future cash flows from operating activities may be affected by the following tax matters:

- Pursuant to the TCJA, beginning in 2018 Generation is expected to have higher operating cash flows in the range of approximately \$1.2 billion to \$1.6 billion for the period from 2018 to 2021, reflecting the reduction in the corporate federal income tax rate and full expensing of capital investments.

The TCJA is generally expected to result in lower operating cash flows for the Utility Registrants as a result of the elimination of bonus depreciation and lower customer rates. Increased operating cash flows for the Utility Registrants from lower corporate federal income tax rates is expected to be more than offset over time by lower customer rates resulting from lower income tax expense recoveries and the settlement of deferred income tax net regulatory liabilities established pursuant to the TCJA, partially offset by the impacts of higher rate base. The amount and timing of settlement of the net regulatory liabilities will be determined by the Utility Registrants' respective rate regulators, subject to certain IRS "normalization" rules. The table below sets forth the Registrants' estimated categorization of their net regulatory liabilities as of December 31, 2017. The amounts in the table below are shown on an after-tax basis reflecting future net cash outflows after taking into consideration the income tax benefits associated with the ultimate settlement with customers.

	Exelon	ComEd	PECO(a)	BGE	PHI	PEPCO	DPL	ACE
Subject to IRS Normalization Rules	$3,040	$1,400	$533	$459	$648	$299	$195	$153
Subject to Rate Regulator Determination	1,694	573	43	324	754	391	194	170
Net Regulatory Liabilities	$4,734	$1,973	$576	$783	$1,402	$690	$389	$323

(a) Given the regulatory treatment of income tax benefits related to electric and gas distribution repairs, PECO remains in an overall net regulatory asset position as of December 31, 2017 after recording the impacts related to the TCJA. As a result, the amount of customer benefits resulting from the TCJA subject to the discretion of PECO's rate regulators are lower relative to the other Utility Registrants. See Note 6 - Regulatory Matters for additional information.

Net regulatory liability amounts subject to normalization rules generally may not be passed back to customers any faster than over the remaining useful lives of the underlying assets giving rise to the associated deferred income taxes. Such deferred income taxes generally relate to property, plant and equipment with remaining useful lives ranging from 30 to 40 years across the Utility Registrants. For the remaining amounts, the pass back period is subject to determinations by the rate regulators.

The Utility Registrants expect to fund any such required incremental operating cash outflows using a combination of third party debt financings and equity funding from Exelon in combinations generally consistent with existing capitalization ratio structures. To fund any

Table of Contents

additional equity contributions to the Utility Registrants, Exelon would have available to it its typical sources, including, but not limited to, the increased operating cash flows at Generation referenced above, which over time are expected to exceed the incremental equity needs at the Utility Registrants.

The Utility Registrants continue to work with their state regulatory commissions to determine the amount and timing of the passing back of TCJA income tax savings benefits to customers; with filings made at PECO, Pepco DC and DPL Delaware and approved filings at ComEd, BGE, Pepco Maryland, DPL Maryland and ACE. The amounts being passed back or proposed to be passed back to customers reflect the benefit of lower income tax expense beginning January 1, 2018 (February 1, 2018 for DPL Delaware), and the settlement of a portion of deferred income tax regulatory liabilities established upon enactment of the TCJA. See Note 6 - Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on their filings.

In general, most states use federal taxable income as the starting point for computing state corporate income tax. Now that the TCJA has been enacted, state governments are beginning to analyze the impact of the TCJA on their state revenues. Exelon is uncertain regarding what the state governments will do, and there is a possibility that state corporate income taxes could change due to the enactment of the TCJA. In 2018, Exelon will be closely monitoring the states' responses to the TCJA as these could have an impact on Exelon's future cash flows.

See Note 12 - Income Taxes of the Combined Notes to Consolidated Financial Information for additional information on the amounts of the net regulatory liabilities subject to determinations by rate regulators.

- State and local governments continue to face increasing financial challenges, which may increase the risk of additional income tax, property taxes and other taxes or the imposition, extension or permanence of temporary tax increases.

Cash flows from operations for the six months ended June 30, 2018 and 2017 by Registrant were as follows:

	Six Months Ended June 30,	
	2018	2017
Exelon	$3,869	$2,895
Generation	2,063	974
ComEd	602	788
PECO	254	368
BGE	464	469
PHI	487	403
Pepco	227	129
DPL	216	194
ACE	67	77

276

Table of Contents

Changes in the Registrants' cash flows from operations were generally consistent with changes in each Registrant's respective results of operations, as adjusted by changes in working capital in the normal course of business, except as discussed below. In addition, significant operating cash flow impacts for the Registrants for the six months ended June 30, 2018 and 2017 were as follows:

Generation

- Depending upon whether Generation is in a net mark-to-market liability or asset position, collateral may be required to be posted with or collected from its counterparties. In addition, the collateral posting and collection requirements differ depending on whether the transactions are on an exchange or in the OTC markets. During the six months ended June 30, 2018 and 2017, Generation had net collections/(payments) of counterparty cash collateral of $91 million and $(163) million, respectively, primarily due to market conditions that resulted in changes to Generation's net mark-to-market position.
- During the six months ended June 30, 2018 and 2017, Generation had net payments of approximately $36 million and $8 million, respectively, related to purchases and sales of options. The level of option activity in a given period may vary due to several factors, including changes in market conditions as well as changes in hedging strategy.

ComEd

- During each of the six months ended June 30, 2018 and 2017, ComEd posted approximately $15 million and $13 million of cash collateral with PJM, respectively. As of June 30, 2018 and 2017, ComEd had approximately $66 million and $36 million cash collateral posted with PJM, respectively. ComEd's total collateral posted with PJM has increased year over year primarily due to an increase in ComEd's peak market activity with PJM.

See Note 18 — Supplemental Financial Information of the Combined Notes to Consolidated Financial Statements for additional information regarding changes in non-cash operating activities.

Cash Flows from Investing Activities

Cash flows used in investing activities for the six months ended June 30, 2018 and 2017 by Registrant were as follows:

	Six Months Ended June 30,	
	2018	2017
Exelon	$(3,846)	$(3,981)
Generation	(1,549)	(1,349)
ComEd	(1,009)	(1,156)
PECO	(406)	(242)
BGE	(428)	(401)
PHI	(627)	(670)
Pepco	(285)	(292)
DPL	(165)	(191)
ACE	(172)	(175)

Table of Contents

Significant investing cash flow impacts for the Registrants for six months ended June 30, 2018 and 2017 were as follows:

Exelon and Generation

- During the six months ended June 30, 2018, Exelon had proceeds of $85 million relating to the sale of its interest in an electrical contracting business that primarily installs, maintains and repairs underground and high-voltage cable transmission and distribution services.
- During the six months ended June 30, 2018, Exelon had expenditures of $57 million relating to the acquisition of the Handley Generating Station.
- During the six months ended June 30, 2017, Exelon had expenditures of $23 million and $182 million relating to the acquisitions of ConEdison Solutions and the FitzPatrick facility, respectively.

Capital Expenditure Spending

Generation

Generation has entered into several agreements to acquire equity interests in privately held development stage entities which develop energy-related technologies. The agreements contain a series of scheduled investment commitments, including in-kind service contributions. There are anticipated expenditures remaining to fund anticipated planned capital and operating needs of the associated companies.

Capital expenditures by Registrant for the six months ended June 30, 2018 and 2017 and projected amounts for the full year 2018 are as follows:

	Projected Full Year 2018[(a)]		Six Months Ended June 30,	
			2018	2017
Exelon	$ 7,900	(b)	$3,807	$3,845
Generation	2,350		1,298	1,189
ComEd[(c)]	2,125		1,026	1,168
PECO	850		411	367
BGE	1,000		434	405
PHI	1,550	(d)	629	671
Pepco	700		287	291
DPL	400		166	192
ACE	425		170	175

(a) Total projected capital expenditures do not include adjustments for non-cash activity.

(b) Includes corporate operations, BSC, and PHISCO rounded to the nearest $25 million.

(c) The capital expenditures and 2018 projections include approximately $83 million of expected incremental spending pursuant to EIMA, ComEd has committed to invest approximately $2.6 billion over a ten-year period, through 2021, to modernize and storm-harden its distribution system and to implement smart grid technology.

(d) Includes PHISCO rounded to the nearest $25 million.

Projected capital expenditures and other investments are subject to periodic review and revision to reflect changes in economic conditions and other factors.

Generation

Approximately 40% and 11% of the projected 2018 capital expenditures at Generation are for the acquisition of nuclear fuel, and the construction of new natural gas plant and solar facilities, respectively, with the remaining amounts reflecting investment in renewable energy and additions and upgrades to existing facilities (including material condition improvements during nuclear refueling outages). Generation anticipates that they will fund capital expenditures with internally generated funds and borrowings.

ComEd, PECO, BGE, Pepco, DPL and ACE

Projected 2018 capital expenditures at the Utility Registrants are for continuing projects to maintain and improve operations, including enhancing reliability and adding capacity to the transmission and distribution systems such as ComEd’s reliability related investments required under EIMA, and the Utility Registrants' construction commitments under PJM’s RTEP.

The Utility Registrants as transmission owners are subject to NERC compliance requirements. NERC provides guidance to transmission owners regarding assessments of transmission lines. The results of these assessments could require the Utility Registrants to incur incremental capital or operating and maintenance expenditures to ensure their transmission lines meet NERC standards. In 2010, NERC provided guidance to transmission owners that recommended the Utility Registrants perform assessments of their transmission lines. ComEd, PECO and BGE submitted their final bi-annual reports to NERC in January 2014. ComEd and PECO will be incurring incremental capital expenditures associated with this guidance following the completion of the assessments. Specific projects and expenditures are identified as the assessments are completed. ComEd’s and PECO’s forecasted 2018 capital expenditures above reflect capital spending for remediation to be completed through 2019. DPL and ACE are complete with their assessments and BGE and Pepco have substantially completed their assessments and thus do not expect significant capital expenditures related to this guidance in 2018.

The Utility Registrants anticipate that they will fund their capital expenditures with a combination of internally generated funds and borrowings and additional capital contributions from parent.

Cash Flows from Financing Activities

Cash flows provided by (used in) financing activities for the six months ended June 30, 2018 and 2017 by Registrant were as follows:

	Six Months Ended June 30,	
	2018	2017
Exelon	$(185)	$983
Generation	(518)	358
ComEd	406	361
PECO	(100)	(144)
BGE	(46)	(100)
PHI	298	245
Pepco	98	274
DPL	88	(43)
ACE	105	2

Table of Contents

Debt

See Note 11 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information of the Registrants' debt issuances.

Dividends

Cash dividend payments and distributions during the six months ended June 30, 2018 and 2017 by Registrant were as follows:

	Six Months Ended June 30,	
	2018	2017
Exelon	$666	$607
Generation	377	330
ComEd	229	211
PECO	293	144
BGE	105	99
PHI	109	131
Pepco	50	58
DPL	40	54
ACE	19	22

Quarterly dividends declared by the Exelon Board of Directors during the six months ended June 30, 2018 and for the third quarter of 2018 were as follows:

Period	Declaration Date	Shareholder of Record Date	Dividend Payable Date	Cash per Share[(a)]
First Quarter 2018	January 30, 2018	February 15, 2018	March 9, 2018	$0.3450
Second Quarter 2018	May 1, 2018	May 15, 2018	June 8, 2018	$0.3450
Third Quarter 2018	July 24, 2018	August 15, 2018	September 10, 2018	$0.3450

(a) Exelon's Board of Directors approved an updated dividend policy providing an increase of 5% each year for the period covering 2018 through 2020, beginning with the March 2018 dividend.

Table of Contents

Short-Term Borrowings

Short-term borrowings incurred (repaid) during the six months ended June 30, 2018 and 2017 by Registrant were as follows:

	Six Months Ended June 30,	
	2018	2017
Exelon	$325	$488
Generation	—	15
ComEd	320	389
PECO	50	—
BGE	59	40
PHI	(103)	(455)
Pepco	(26)	(23)
DPL	(216)	25
ACE	139	42

Contributions from Parent/Member

Contributions received from Parent/Member for the six months ended June 30, 2018 and 2017 by Registrant were as follows:

	Six Months Ended June 30,	
	2018	2017
ComEd[(a)(b)]	$225	$184
PECO[(b)]	41	—
PHI[(b)]	235	751
Pepco[(c)]	85	161
DPL[(c)]	150	—

____

(a) Additional contributions from parent or external debt financing may be required as a result of increased capital investment in infrastructure improvements and modernization pursuant to EIMA and transmission upgrades.

(b) Contribution paid by Exelon.

(c) Contribution paid by PHI.

Other

For the six months ended June 30, 2018, other financing activities primarily consist of debt issuance costs. See Note 11 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information of the Registrants' debt issuances.

Credit Matters

The Registrants fund liquidity needs for capital investment, working capital, energy hedging and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets and large, diversified credit facilities. The credit facilities include $9.5 billion in aggregate total commitments of which $8.0 billion was available as of June 30, 2018, and of which no financial institution has more than 7% of the aggregate commitments for the Registrants. The Registrants had access to the commercial paper market during the second quarter of 2018 to fund their

Table of Contents

short-term liquidity needs, when necessary. The Registrants routinely review the sufficiency of their liquidity position, including appropriate sizing of credit facility commitments, by performing various stress test scenarios, such as commodity price movements, increases in margin-related transactions, changes in hedging levels and the impacts of hypothetical credit downgrades. The Registrants have continued to closely monitor events in the financial markets and the financial institutions associated with the credit facilities, including monitoring credit ratings and outlooks, credit default swap levels, capital raising and merger activity. See PART I. ITEM 1A. RISK FACTORS of the Exelon 2017 Form 10-K for additional information regarding the effects of uncertainty in the capital and credit markets.

The Registrants believe their cash flow from operating activities, access to credit markets and their credit facilities provide sufficient liquidity. If Generation lost its investment grade credit rating as of June 30, 2018, it would have been required to provide incremental collateral of $1.5 billion to meet collateral obligations for derivatives, non-derivatives, normal purchases and normal sales contracts and applicable payables and receivables, net of the contractual right of offset under master netting agreements, which is well within its current available credit facility capacities of $4.4 billion.

The following table presents the incremental collateral that each Utility Registrant would have been required to provide in the event each Utility Registrant lost its investment grade credit rating at June 30, 2018 and available credit facility capacity prior to any incremental collateral at June 30, 2018:

	PJM Credit Policy Collateral	Other Incremental Collateral Required[(a)]	Available Credit Facility Capacity Prior to Any Incremental Collateral
ComEd	$ 9	$ —	$ 998
PECO	1	20	600
BGE	12	36	599
Pepco	11	—	300
DPL	4	11	300
ACE	—	—	300

(a) Represents incremental collateral related to natural gas procurement contracts.

Exelon Credit Facilities

Exelon Corporate, ComEd, BGE, Pepco, DPL and ACE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the intercompany money pool. PHI Corporate meets its short-term liquidity requirements primarily through the issuance of short-term notes and the Exelon intercompany money pool. The Registrants may use their respective credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit.

Table of Contents

The following table reflects the Registrants' commercial paper programs supported by the revolving credit agreements and bilateral credit agreements at June 30, 2018:
Commercial Paper Programs

Commercial Paper Issuer	Maximum Program Size[(a)(b)]	Outstanding Commercial Paper at June 30, 2018	Average Interest Rate on Commercial Paper Borrowings for the Six Months Ended June 30, 2018
Exelon Corporate	$ 600	$ —	1.92 %
Generation	5,300	—	1.94 %
ComEd	1,000	320	2.09 %
PECO	600	50	2.23 %
BGE	600	136	2.08 %
Pepco	500	—	2.18 %
DPL	500	—	2.07 %
ACE	350	122	2.10 %

(a) Excludes $545 million bilateral credit facilities that do not back Generation's commercial paper program.
(b) Excludes additional credit facility agreements for Generation, ComEd, PECO, BGE, Pepco, DPL and ACE with aggregate commitments of $49 million, $34 million, $34 million, $5 million, $2 million, $2 million and $2 million, respectively, arranged with minority and community banks located primarily within utilities' service territories. These facilities expire on October 12, 2018. These facilities are solely utilized to issue letters of credit. As of June 30, 2018, letters of credit issued under these agreements for Generation and BGE totaled $5 million and $2 million, respectively.

Table of Contents

In order to maintain their respective commercial paper programs in the amounts indicated above, each Registrant must have credit facilities in place, at least equal to the amount of its commercial paper program. While the amount of outstanding commercial paper does not reduce available capacity under a Registrant's credit facility, a Registrant does not issue commercial paper in an aggregate amount exceeding the then available capacity under its credit facility. At June 30, 2018, the Registrants had the following aggregate bank commitments, credit facility borrowings and available capacity under their respective credit facilities:

Borrower	Facility Type	Aggregate Bank Commitment(a)(b)(c)	Facility Draws	Outstanding Letters of Credit(c)	Available Capacity at June 30, 2018	
					Actual	To Support Additional Commercial Paper(b)(d)
Exelon Corporate	Syndicated Revolver	$ 600	$ —	$ 24	$ 576	$ 576
Generation	Syndicated Revolver	5,300	—	1,113	4,187	4,187
Generation	Bilaterals	545	—	356	189	—
ComEd	Syndicated Revolver	1,000	—	2	998	678
PECO	Syndicated Revolver	600	—	—	600	550
BGE	Syndicated Revolver	600	—	1	599	463
Pepco	Syndicated Revolver	300	—	—	300	300
DPL	Syndicated Revolver	300	—	—	300	300
ACE	Syndicated Revolver	300	—	—	300	178

(a) Excludes $128 million of credit facility agreements arranged at minority and community banks at Generation, ComEd, PECO, BGE, Pepco, DPL and ACE. These facilities expire on October 12, 2018. These facilities are solely utilized to issue letters of credit. As of June 30, 2018, letters of credit issued under these agreements for Generation and BGE totaled $5 million and $2 million, respectively.

(b) Pepco, DPL and ACE's revolving credit facility is subject to available borrowing capacity. The borrowing capacity may be increased or decreased during the term of the facility, except that (i) the sum of the borrowing capacity must equal the total amount of the facility, and (ii) the aggregate amount of credit used at any given time by each of Pepco, DPL or ACE may not exceed $900 million or the maximum amount of short-term debt the Registrant is permitted to have outstanding by its regulatory authorities. The total number of the borrowing reallocations may not exceed eight per year during the term of the facility

(c) Excludes nonrecourse debt letters of credit, see Note 13 — Debt and Credit Agreements in the Exelon 2017 Form 10-K for additional information.

(d) Excludes $545 million bilateral credit facilities that do not back Generation's commercial paper program.

As of June 30, 2018, there were no borrowings under Generation's bilateral credit facilities.

Table of Contents

Borrowings under Exelon Corporate’s, Generation’s, ComEd’s, PECO’s, BGE's, Pepco's, DPL's and ACE's revolving credit agreements bear interest at a rate based upon either the prime rate or a LIBOR-based rate, plus an adder based upon the particular Registrant’s credit rating. The adders for the prime based borrowings and LIBOR-based borrowings are presented in the following table:

	Exelon Corporate	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
Prime based borrowings	27.5	27.5	7.5	0.0	0.0	7.5	7.5	7.5
LIBOR-based borrowings	127.5	127.5	107.5	90.0	100.0	107.5	107.5	107.5

The maximum adders for prime rate borrowings and LIBOR-based rate borrowings are 90 basis points and 165 basis points, respectively. The credit agreements also require the borrower to pay a facility fee based upon the aggregate commitments. The fee varies depending upon the respective credit ratings of the borrower.

Each revolving credit agreement for Exelon Corporate, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE requires the affected borrower to maintain a minimum cash from operations to interest expense ratio for the twelve-month period ended on the last day of any quarter. The following table summarizes the minimum thresholds reflected in the credit agreements for the six months ended June 30, 2018:

	Exelon Corporate	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
Credit agreement threshold	2.50 to 1	3.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1

At June 30, 2018, the interest coverage ratios at the Registrants were as follows:

	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
Interest coverage ratio	6.93	10.89	12.33	7.54	10.29	6.09	8.08	5.35

An event of default under Exelon, Generation, ComEd, PECO or BGE's indebtedness will not constitute an event of default under any of the others’ credit facilities, except that a bankruptcy or other event of default in the payment of principal, premium or indebtedness in principal amount in excess of $100 million in the aggregate by Generation will constitute an event of default under the Exelon Corporate credit facility. An event of default under Pepco, DPL or ACE's indebtedness will not constitute an event of default with respect to the other PHI Utilities under the PHI Utilities' combined credit facility.

The absence of a material adverse change in Exelon's or PHI’s business, property, results of operations or financial condition is not a condition to the availability of credit under any of the borrowers' credit agreement. None of the credit agreements include any rating triggers.

Security Ratings

The Registrants’ access to the capital markets, including the commercial paper market, and their respective financing costs in those markets, may depend on the securities ratings of the entity that is accessing the capital markets.

The Registrants’ borrowings are not subject to default or prepayment as a result of a downgrading of securities, although such a downgrading of a Registrant’s securities could increase fees and interest charges under that Registrant’s credit agreements.

Table of Contents

As part of the normal course of business, the Registrants enter into contracts that contain express provisions or otherwise permit the Registrants and their counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable contracts law, if the Registrants are downgraded by a credit rating agency, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance, which could include the posting of collateral. See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on collateral provisions.

Intercompany Money Pool

To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing, both Exelon and PHI operate an intercompany money pool. Maximum amounts contributed to and borrowed from the money pool by participant and the net contribution or borrowing as of June 30, 2018, are presented in the following table:

Exelon Intercompany Money Pool	During the Three Months Ended June 30, 2018		As of June 30, 2018
Contributed (Borrowed)	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
Exelon Corporate	$ 674	$ —	$ 260
Generation	225	(54)	185
PECO	—	(420)	(233)
BSC	—	(379)	(261)
PHI Corporate	—	(33)	(8)
PCI	57	(1)	57

PHI Intercompany Money Pool	During the Three Months Ended June 30, 2018		As of June 30, 2018
Contributed (Borrowed)	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
PHI Corporate	$ 33	$ (1)	$ 15
PHISCO	13	(31)	(13)

Investments in Nuclear Decommissioning Trust Funds

Exelon, Generation and CENG maintain trust funds, as required by the NRC, to fund certain costs of decommissioning nuclear plants. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to offset inflationary increases in decommissioning costs. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocations in accordance with Generation’s NDT fund investment policy. Generation’s and CENG’s investment policies establish limits on the concentration of holdings in any one company and also in any one industry. See Note 13 —Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for additional information regarding the trust funds, the NRC’s minimum funding requirements and related liquidity ramifications.

Shelf Registration Statements

Exelon, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE have a currently effective combined shelf registration statement unlimited in amount, filed with the SEC, that will expire in August 2019. The ability of each Registrant to sell securities off the shelf registration statement or to access the private placement markets will depend on a number of factors at the time of the proposed sale, including

Table of Contents

other required regulatory approvals, as applicable, the current financial condition of the Registrant, its securities ratings and market conditions.

Regulatory Authorizations

ComEd, PECO, BGE, Pepco, DPL and ACE are required to obtain short-term and long-term financing authority from Federal and State Commissions as follows:

	As of June 30, 2018					
	Short-term Financing Authority[a]			Remaining Long-term Financing Authority[a]		
	Commission	Expiration Date	Amount	Commission	Expiration Date	Amount
ComEd[b]	FERC	December 31, 2019	$ 2,500	ICC	2019	$ 583
PECO	FERC	December 31, 2019	1,500	PAPUC	December 31, 2018	950
BGE	FERC	December 31, 2019	700	MDPSC	N/A	700
Pepco	FERC	December 31, 2019	500	MDPSC / DCPSC	December 31, 2020	500
DPL	FERC	December 31, 2019	500	MDPSC / DPSC	December 31, 2020	150
ACE	NJBPU	December 31, 2019	350	NJBPU	December 31, 2019	350

(a) Generation currently has blanket financing authority it received from FERC in connection with its market-based rate authority.

(b) ComEd had $440 million available in long-term debt refinancing authority and $143 million available in new money long-term debt financing authority from the ICC as of June 30, 2018 and has an expiration date of June 1, 2019 and March 1, 2019, respectively. On April 9, 2018, ComEd filed an application for $1.5 billion in new money long-term debt financing authority from the ICC and received approval on July 25, 2018.

Contractual Obligations and Off-Balance Sheet Arrangements

Contractual obligations represent cash obligations that are considered to be firm commitments and commercial commitments triggered by future events. See Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements in the Exelon 2017 Form 10-K.

Generation, ComEd, PECO, BGE, Pepco, DPL and ACE have obligations related to contracts for the purchase of power and fuel supplies, and ComEd and PECO have obligations related to their financing trusts. The power and fuel purchase contracts and the financing trusts have been considered for consolidation in the Registrants' respective financial statements pursuant to the authoritative guidance for VIEs. See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for additional information.

For an in-depth discussion of the Registrants' contractual obligations and off-balance sheet arrangements, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Contractual Obligations and Off-Balance Sheet Arrangements" in the Exelon 2017 Form 10-K.

Table of Contents

Item 3. Quantitative and Qualitative Disclosures about Market Risk

The Registrants are exposed to market risks associated with adverse changes in commodity prices, counterparty credit, interest rates and equity prices. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief executive officer and includes the chief risk officer, chief strategy officer, chief executive officer of Exelon Utilities, chief commercial officer, chief financial officer and chief executive officer of Constellation. The RMC reports to the Finance and Risk Committee of the Exelon Board of Directors on the scope of the risk management activities. The following discussion serves as an update to ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK of Exelon's 2017 Annual Report on Form 10-K incorporated herein by reference.

Commodity Price Risk (All Registrants)

Commodity price risk is associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies and other factors. To the extent the total amount of energy Exelon generates and purchases differs from the amount of energy it has contracted to sell, Exelon is exposed to market fluctuations in commodity prices. Exelon seeks to mitigate its commodity price risk through the sale and purchase of electricity, fossil fuel and other commodities.

Generation

Electricity available from Generation's owned or contracted generation supply in excess of Generation's obligations to customers, including portions of the Utility Registrants' retail load, is sold into the wholesale markets. To reduce commodity price risk caused by market fluctuations, Generation enters into non-derivative contracts as well as derivative contracts, including swaps, futures, forwards and options, with approved counterparties to hedge anticipated exposures. Generation uses derivative instruments as economic hedges to mitigate exposure to fluctuations in commodity prices. Generation expects the settlement of the majority of its economic hedges will occur during 2018 through 2020.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions which have not been hedged. Exelon's hedging program involves the hedging of commodity price risk for Exelon's expected generation, typically on a ratable basis over three-year periods. As of June 30, 2018, the percentage of expected generation hedged is 97%-100%, 71%-74% and 41%-44% for 2018, 2019 and 2020, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted generating facilities 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. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts including Generation's sales to the ComEd, PECO and BGE to serve their retail load.

A portion of Generation's hedging strategy may be accomplished with fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. Market price risk exposure is the risk of a change in the value of unhedged positions. The forecasted market price risk exposure for Generation's entire economic hedge portfolio associated with a $5 reduction in the annual average around-the-clock energy price based on June 30, 2018 market conditions and hedged position would be an increase in pre-tax net income of approximately $13 million for 2018 and decreases of approximately $269 million and $549 million, respectively, for 2019 and 2020. Power price sensitivities are derived by adjusting power price assumptions while keeping all other price inputs constant.

Table of Contents

Generation actively manages its portfolio to mitigate market price risk exposure for its unhedged position. Actual results could differ depending on the specific timing of, and markets affected by, price changes, as well as future changes in Generation’s portfolio. See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Retail Competition

Constellation competes for retail customers in a competitive environment, which affects the margins that Generation can earn and the volumes that it is able to serve. In periods of sustained low natural gas and power prices and low market volatility, retail competitors can aggressively pursue market share because the barriers to entry can be low and wholesale generators (including Generation) use their retail hedge generation output. Increased or more aggressive competition could adversely affect Generation's overall gross margins and profitability.

Proprietary Trading Activities

Proprietary trading portfolio activity for the six months ended June 30, 2018 resulted in $35 million of pre-tax gains due to net mark-to-market gains of $17 million and realized gains of $18 million. Generation has not segregated proprietary trading activity within the following discussion because of the relative size of the proprietary trading portfolio in comparison to Generation’s total Revenue net of purchase power and fuel expense. See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Fuel Procurement

Generation procures natural gas through long-term and short-term contracts, and spot-market purchases. Nuclear fuel assemblies are obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation’s procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 59% of Generation’s uranium concentrate requirements from 2018 through 2022 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon’s and Generation’s results of operations, cash flows and financial positions.

ComEd

ComEd entered into 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The annual commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. Pursuant to the ICC’s Order on December 19, 2012, ComEd’s commitments under the existing long-term contracts were reduced for the June 2013 through May 2014 procurement period. In addition, the ICC’s December 18, 2013 Order approved the reduction of ComEd’s commitments under those contracts for the June 2014 through May 2015 procurement period, and the amount of the reduction was approved by the ICC in March 2014.

ComEd has block energy contracts to procure electric supply that are executed through a competitive procurement process, which is further discussed in Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements. The block energy contracts are considered derivatives and qualify for the normal purchases and normal sales scope exception under current

Table of Contents

derivative authoritative guidance, and as a result are accounted for on an accrual basis of accounting. ComEd does not enter into derivatives for speculative or proprietary trading purposes. See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on these contracts.

PECO, BGE, Pepco, DPL and ACE

BGE, Pepco, DPL and ACE have certain full requirements contracts, which are considered derivatives and qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance, and as a result are accounted for on an accrual basis of accounting. Other full requirements contracts are not derivatives.

PECO, BGE and DPL have also executed derivative natural gas contracts, which either qualify for the normal purchases and normal sales exception or have no mark-to-market balances because the derivatives are index priced, to hedge their long-term price risk in the natural gas market. The hedging programs for natural gas procurement have no direct impact on their results of operations or financial position.

PECO, BGE, Pepco, DPL and ACE do not enter into derivatives for speculative or proprietary trading purposes. See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on these contracts.

Trading and Non-Trading Marketing Activities

The following tables detail Exelon’s, Generation’s, ComEd’s, PHI's and DPL's trading and non-trading marketing activities is included to address the recommended disclosures by the energy industry’s Committee of Chief Risk Officers (CCRO).

Table of Contents

The following table provides detail on changes in Exelon's, Generation's, ComEd's, PHI's and DPL's commodity mark-to-market net asset or liability balance sheet position from December 31, 2017 to June 30, 2018. It indicates the drivers behind changes in the balance sheet amounts. This table incorporates the mark-to-market activities that are immediately recorded in earnings. This table excludes all NPNS contracts and does not segregate proprietary trading activity. See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of June 30, 2018 and December 31, 2017.

	Exelon	Generation	ComEd	PHI	DPL
Total mark-to-market energy contract net assets (liabilities) at December 31, 2017[a]	$ 667	$ 923	$ (256)	$ —	$ —
Total change in fair value during 2018 of contracts recorded in results of operations	194	194	—	—	—
Reclassification to realized of contracts recorded in results of operations	(354)	(354)	—	—	—
Changes in fair value — recorded through regulatory assets and liabilities[b]	5	—	4	1	1
Changes in allocated collateral	(85)	(84)	—	(1)	(1)
Net option premium paid/(received)	36	36	—	—	—
Option premium amortization	7	7	—	—	—
Total mark-to-market energy contract net assets (liabilities) at June 30,2018[a]	$ 470	$ 722	$ (252)	$ —	$ —

(a) Amounts are shown net of collateral paid to and received from counterparties.

(b) For ComEd and DPL, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of June 30, 2018, ComEd recorded a regulatory liability of $252 million related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. For the six months ended June 30, 2018, ComEd also recorded $6 million of decreases in fair value and an increase for realized losses due to settlements of $10 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers.

Fair Values

The following tables present maturity and source of fair value for Exelon, Generation and ComEd mark-to-market commodity contract net assets (liabilities). The tables provide two fundamental pieces of information. First, the tables provide the source of fair value used in determining the carrying amount of the Registrants' total mark-to-market net assets (liabilities), net of allocated collateral. Second, the tables show the maturity, by year, of the Registrants' commodity contract net assets (liabilities), net of allocated collateral, giving an indication of when these mark-to-market amounts will settle and either generate or require cash. See Note 9 — Fair Value of Financial Assets and Liabilities of the Combined Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

Table of Contents

Exelon

	Maturities Within						
	2018	2019	2020	2021	2022	2023 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts[a][b]:							
Actively quoted prices (Level 1)	$4	$(36)	$(30)	$(2)	$(5)	$ 13	$ (56)
Prices provided by external sources (Level 2)	34	(7)	12	2	—	—	41
Prices based on model or other valuation methods (Level 3)[c]	283	289	73	(24)	(61)	(75)	485
Total	$321	$246	$55	$(24)	$(66)	$ (62)	$ 470

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in results of operations.

(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $382 million at June 30, 2018.

(c) Includes ComEd’s net liabilities associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Generation

	Maturities Within						
	2018	2019	2020	2021	2022	2023 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts[a][b]:							
Actively quoted prices (Level 1)	$4	$(36)	$(30)	$(2)	$(5)	$ 13	$ (56)
Prices provided by external sources (Level 2)	34	(7)	12	2	—	—	41
Prices based on model or other valuation methods (Level 3)	295	313	97	—	(37)	69	737
Total	$333	$270	$79	$—	$(42)	$ 82	$ 722

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in the results of operations.

(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $382 million at June 30, 2018.

ComEd

	Maturities Within						
	2018	2019	2020	2021	2022	2023 and Beyond	Total Fair Value
Commodity derivative contracts[a]:							
Prices based on model or other valuation methods (Level 3)	$(12)	$(24)	$(24)	$(24)	$(24)	$(144)	$ (252)

(a) Represents ComEd’s net liabilities associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Table of Contents

Credit Risk, Collateral and Contingent-Related Features (All Registrants)

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that execute derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for detailed information of credit risk, collateral and contingent-related features.

Generation

The following tables provide information on Generation's credit exposure for all derivative instruments, normal purchases and normal sales agreements, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of June 30, 2018. The tables further disaggregate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties and an indication of the duration of a company's credit risk by credit rating of the counterparties. The figures in the tables below exclude credit risk exposure from individual retail customers, uranium procurement contracts, and exposure through RTOs, ISOs and commodity exchanges, which are discussed below. Additionally, the figures in the tables below exclude exposures with affiliates, including net receivables with ComEd, PECO, BGE, Pepco, DPL and ACE of $47 million, $23 million, $23 million, $31 million, $5 million and $4 million as of June 30, 2018, respectively.

Rating as of June 30, 2018	Total Exposure Before Credit Collateral	Credit Collateral[a]	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 823	$ —	$ 823	1	$ 206
Non-investment grade	90	30	60		
No external ratings					
Internally rated — investment grade	228	—	228		
Internally rated — non-investment grade	78	13	65		
Total	$ 1,219	$ 43	$ 1,176	1	$ 206

	Maturity of Credit Risk Exposure			
Rating as of June 30, 2018	Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$774	$ 47	$ 2	$ 823
Non-investment grade	82	8	—	90
No external ratings				
Internally rated — investment grade	165	33	30	228
Internally rated — non-investment grade	79	(1)	—	78
Total	$1,100	$ 87	$ 32	$ 1,219

Table of Contents

Net Credit Exposure by Type of Counterparty	As of June 30, 2018
Financial institutions	$ 97
Investor-owned utilities, marketers, power producers	627
Energy cooperatives and municipalities	392
Other	60
Total	$ 1,176

(a) As of June 30, 2018, credit collateral held from counterparties where Generation had credit exposure included $22 million of cash and $21 million of letters of credit.

The Utility Registrants

There have been no significant changes or additions to the Utility Registrants exposures to credit risk that are described in ITEM 1A. RISK FACTORS of Exelon's 2017 Annual Report on Form 10-K.

See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding credit exposure to suppliers.

Collateral (All Registrants)

Generation

As part of the normal course of business, Generation routinely enters into physical or financial contracts for the sale and purchase of electricity, natural gas and other commodities. In accordance with the contracts and applicable law, if Generation is downgraded by a credit rating agency, especially if such downgrade is to a level below investment grade, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance. Depending on Generation's net position with a counterparty, the demand could be for the posting of collateral. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding collateral requirements. See Note 17 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding the letters of credit supporting the cash collateral.

Generation transacts output through bilateral contracts. The bilateral contracts are subject to credit risk, which relates to the ability of counterparties to meet their contractual payment obligations. Any failure to collect these payments from counterparties could have a material impact on Exelon's and Generation's results of operations, cash flows and financial positions. As market prices rise above or fall below contracted price levels, Generation is required to post collateral with purchasers; as market prices fall below contracted price levels, counterparties are required to post collateral with Generation. To post collateral, Generation depends on access to bank credit facilities, which serve as liquidity sources to fund collateral requirements. See ITEM 2. Liquidity and Capital Resources — Credit Matters — Exelon Credit Facilities for additional information.

The Utility Registrants

As of June 30, 2018, ComEd held $5 million in collateral from suppliers in association with energy procurement contracts, $14 million in collateral from suppliers for REC and ZEC contract obligations and $19 million in collateral from suppliers for long-term renewable energy contracts. BGE is not required to post collateral under its electric supply contracts but was holding an immaterial amount of collateral under its electric supply procurement contracts. BGE was not required to post collateral under its natural gas procurement contracts but was holding an immaterial amount of collateral under its natural gas procurement contracts. PECO, Pepco, DPL and ACE were not required to post collateral under their energy and/or natural gas procurement contracts. See Note 6 — Regulatory Matters and Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

RTOs and ISOs (All Registrants)

All Registrants participate in all, or some, of the established wholesale spot energy markets that are administered by PJM, ISO-NE, ISO-NY, CAISO, MISO, SPP, AESO, OIESO and ERCOT. ERCOT is not subject to regulation by FERC but performs a similar function in Texas to that performed by RTOs in markets regulated by FERC. In these areas, power is traded through bilateral agreements between buyers and sellers and on the spot energy markets that are administered by the RTOs or ISOs, as applicable. In areas where there are no spot energy markets, electricity is purchased and sold solely through bilateral agreements. For sales into the spot energy markets administered by an RTO or ISO, the RTO or ISO maintains financial assurance policies that are established and enforced by those administrators. The credit policies of the RTOs and ISOs may, under certain circumstances, require that losses arising from the default of one member on spot energy market transactions be shared by the remaining participants. Non-performance or non-payment by a major counterparty could result in a material adverse impact on the Registrants' results of operations, cash flows and financial positions.

Exchange Traded Transactions (Exelon, Generation, PHI and DPL)

Generation enters into commodity transactions on NYMEX, ICE, NASDAQ, NGX and the Nodal exchange ("the Exchanges"). DPL enters into commodity transactions on ICE. The Exchange clearinghouses act as the counterparty to each trade. Transactions on the Exchanges must adhere to comprehensive collateral and margining requirements. As a result, transactions on the Exchanges are significantly collateralized and have limited counterparty credit risk.

Interest Rate and Foreign Exchange Risk (All Registrants)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants may also utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to lock in rate levels, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At June 30, 2018, Exelon had $800 million of notional amounts of fixed-to-floating hedges outstanding and Exelon and Generation had $624 million of notional amounts of floating-to-fixed hedges outstanding. Assuming the fair value and interest rate hedges are 100% effective, a hypothetical 50 basis point increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in approximately a $3 million decrease in Exelon Consolidated pre-tax income for the six months ended June 30, 2018. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges. See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Equity Price Risk (Exelon and Generation)

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning its nuclear plants. As of June 30, 2018, Generation's decommissioning trust funds are reflected at fair value on its Consolidated Balance Sheets. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to compensate Generation for inflationary increases in decommissioning costs; however, the equity securities in the trust funds are

Table of Contents

exposed to price fluctuations in equity markets, and the value of fixed-rate, fixed-income securities are exposed to changes in interest rates. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocation in accordance with Generation’s NDT fund investment policy. A hypothetical 10% increase in interest rates and decrease in equity prices would result in a $590 million reduction in the fair value of the trust assets. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices. See ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for additional information of equity price risk as a result of the current capital and credit market conditions.

Item 4. Controls and Procedures

During the second quarter of 2018, each of Exelon’s, Generation’s, ComEd’s, PECO’s, BGE’s, PHI's, Pepco's, DPL's and ACE's management, including its principal executive officer and principal financial officer, evaluated its disclosure controls and procedures related to the recording, processing, summarizing and reporting of information in its periodic reports that it files with the SEC. These disclosure controls and procedures have been designed by all Registrants to ensure that (a) material information relating to that Registrant, including its consolidated subsidiaries, is accumulated and made known to Exelon’s management, including its principal executive officer and principal financial officer, by other employees of that Registrant and its subsidiaries as appropriate to allow timely decisions regarding required disclosure, and (b) this information is recorded, processed, summarized, evaluated and reported, as applicable, within the time periods specified in the SEC’s rules and forms. Due to the inherent limitations of control systems, not all misstatements may be detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls could be circumvented by the individual acts of some persons or by collusion of two or more people.

Accordingly, as of June 30, 2018, the principal executive officer and principal financial officer of each of Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE concluded that such Registrant’s disclosure controls and procedures were effective to accomplish its objectives. All Registrants continually strive to improve their disclosure controls and procedures to enhance the quality of its financial reporting and to maintain dynamic systems that change as conditions warrant. There have been no changes in internal control over financial reporting that occurred during the second quarter of 2018 that have materially affected, or are reasonably likely to materially affect, any of Exelon’s, Generation’s, ComEd’s, PECO’s, BGE’s, PHI’s, Pepco’s, DPL’s and ACE’s internal control over financial reporting.

Table of Contents

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

The Registrants are parties to various lawsuits and regulatory proceedings in the ordinary course of their respective businesses. For information regarding material lawsuits and proceedings, see (a) ITEM 3. LEGAL PROCEEDINGS of Exelon's 2017 Form 10-K and (b) Notes 6 — Regulatory Matters and 17 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements in PART I, ITEM 1. FINANCIAL STATEMENTS of this Report. Such descriptions are incorporated herein by these references.

Item 1A. Risk Factors

Risks Related to Exelon

At June 30, 2018, the Registrants' risk factors were consistent with the risk factors described in the Registrants' combined 2017 Form 10-K in ITEM 1A. RISK FACTORS.

Item 4. Mine Safety Disclosures

All Registrants

Not applicable to the Registrants.

Table of Contents

Item 6. Exhibits

Certain of the following exhibits are incorporated herein by reference under Rule 12b-32 of the Securities and Exchange Act of 1934, as amended. Certain other instruments which would otherwise be required to be listed below have not been so listed because such instruments do not authorize securities in an amount which exceeds 10% of the total assets of the applicable Registrant and its subsidiaries on a consolidated basis and the relevant Registrant agrees to furnish a copy of any such instrument to the Commission upon request.

Exhibit No.	Description
3.1	Amended and Restated Articles of Incorporation of Exelon Corporation, as amended on July 24, 2018 (File No. 001-16169, Form 8-K dated July 27, 2018, Exhibit 3.1)
3.2	Amended and Restated Bylaws of Exelon Corporation, as amended on July 24, 2018 (File No. 001-16169, Form 8-K dated July 27, 2018, Exhibit 3.2)
4.1	Supplemental Indenture, dated as of June 1, 2018, from Delmarva Power & Light Company to The Bank of New York Mellon, as trustee (File No. 001-01405, Form 8-K dated June 21, 2018, Exhibit 4.2)
4.2	Supplemental Indenture, dated as of June 1, 2018, from Potomac Electric Power Company to The Bank of New York Mellon, as trustee (File No. 001-01072, Form 8-K dated June 21, 2018, Exhibit 4.2)
10.1	Purchase Agreement, dated June 8, 2018 among Delmarva Power & Light Company and the purchasers signatory thereto (File No. 001-01405, Form 8-K dated June 21, 2018, Exhibit 1.1)
10.2	Purchase Agreement, dated June 8, 2018 among Potomac Electric Power Company and the purchasers signatory thereto (File No. 001-01072, Form 8-K dated June 21, 2018, Exhibit 1.1)
10.3	Letter Agreement, dated May 7, 2018 between Exelon Corporation and Denis P. O'Brien
10.4	Letter Agreement, dated May 7, 2018, between Exelon Corporation and Jonathan W. Thayer
101.INS	XBRL Instance
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation
101.DEF	XBRL Taxonomy Extension Definition
101.LAB	XBRL Taxonomy Extension Labels
101.PRE	XBRL Taxonomy Extension Presentation

Table of Contents

Certifications Pursuant to Rule 13a-14(a) and 15d-14(a) of the Securities and Exchange Act of 1934 as to the Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2018 filed by the following officers for the following companies:

31-1 — Filed by Christopher M. Crane for Exelon Corporation

31-2 — Filed by Joseph Nigro for Exelon Corporation

31-3 — Filed by Kenneth W. Cornew for Exelon Generation Company, LLC

31-4 — Filed by Bryan P. Wright for Exelon Generation Company, LLC

31-5 — Filed by Joseph Dominguez for Commonwealth Edison Company

31-6 — Filed by Jeanne M. Jones for Commonwealth Edison Company

31-7 — Filed by Michael A. Innocenzo for PECO Energy Company

31-8 — Filed by Phillip S. Barnett for PECO Energy Company

31-9 — Filed by Calvin G. Butler, Jr. for Baltimore Gas and Electric Company

31-10 — Filed by David M. Vahos for Baltimore Gas and Electric Company

31-11 — Filed by David M. Velazquez for Pepco Holdings LLC

31-12 — Filed by Robert M. Aiken for Pepco Holdings LLC

31-13 — Filed by David M. Velazquez for Potomac Electric Power Company

31-14 — Filed by Robert M. Aiken for Potomac Electric Power Company

31-15 — Filed by David M. Velazquez for Delmarva Power & Light Company

31-16 — Filed by Robert M. Aiken for Delmarva Power & Light Company

31-17 — Filed by David M. Velazquez for Atlantic City Electric Company

31-18 — Filed by Robert M. Aiken for Atlantic City Electric Company

Table of Contents

Certifications Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code (Sarbanes — Oxley Act of 2002) as to the Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2018 filed by the following officers for the following companies:

32-1 — Filed by Christopher M. Crane for Exelon Corporation

32-2 — Filed by Joseph Nigro for Exelon Corporation

32-3 — Filed by Kenneth W. Cornew for Exelon Generation Company, LLC

32-4 — Filed by Bryan P. Wright for Exelon Generation Company, LLC

32-5 — Filed by Joseph Dominguez for Commonwealth Edison Company

32-6 — Filed by Jeanne M. Jones for Commonwealth Edison Company

32-7 — Filed by Michael A. Innocenzo for PECO Energy Company

32-8 — Filed by Phillip S. Barnett for PECO Energy Company

32-9 — Filed by Calvin G. Butler, Jr. for Baltimore Gas and Electric Company

32-10 — Filed by David M. Vahos for Baltimore Gas and Electric Company

32-11 — Filed by David M. Velazquez for Pepco Holdings LLC

32-12 — Filed by Robert M. Aiken for Pepco Holdings LLC

32-13 — Filed by David M. Velazquez for Potomac Electric Power Company

32-14 — Filed by Robert M. Aiken for Potomac Electric Power Company

32-15 — Filed by David M. Velazquez for Delmarva Power & Light Company

32-16 — Filed by Robert M. Aiken for Delmarva Power & Light Company

32-17 — Filed by David M. Velazquez for Atlantic City Electric Company

32-18 — Filed by Robert M. Aiken for Atlantic City Electric Company

Table of Contents

SIGNATURES

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

/s/ CHRISTOPHER M. CRANE	/s/ JOSEPH NIGRO
Christopher M. Crane	Joseph Nigro
President and Chief Executive Officer	Senior Executive Vice President and Chief Financial Officer
(Principal Executive Officer) and Director	(Principal Financial Officer)

/s/ FABIAN E. SOUZA
Fabian E. Souza
Senior Vice President and Corporate Controller
(Principal Accounting Officer)
August 2, 2018

Table of Contents

Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.
EXELON GENERATION COMPANY, LLC

/s/ KENNETH W. CORNEW	/s/ BRYAN P. WRIGHT
Kenneth W. Cornew	Bryan P. Wright
President and Chief Executive Officer	Senior Vice President and Chief Financial Officer
(Principal Executive Officer)	(Principal Financial Officer)

/s/ MATTHEW N. BAUER
Matthew N. Bauer
Vice President and Controller
(Principal Accounting Officer)
August 2, 2018

Table of Contents

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

/s/ JOSEPH DOMINGUEZ	/s/ JEANNE M. JONES
Joseph Dominguez	Jeanne M. Jones
Chief Executive Officer	Senior Vice President, Chief Financial Officer and Treasurer
(Principal Executive Officer)	(Principal Financial Officer)

/s/ GERALD J. KOZEL
Gerald J. Kozel
Vice President and Controller
(Principal Accounting Officer)
August 2, 2018

Table of Contents

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

/s/ MICHAEL A. INNOCENZO	/s/ PHILLIP S. BARNETT
Michael A. Innocenzo	Phillip S. Barnett
President and Chief Executive Officer	Senior Vice President, Chief Financial Officer and Treasurer
(Principal Executive Officer)	(Principal Financial Officer)

/s/ SCOTT A. BAILEY
Scott A. Bailey
Vice President and Controller
(Principal Accounting Officer)
August 2, 2018

Table of Contents

Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.
BALTIMORE GAS AND ELECTRIC COMPANY

/s/ CALVIN G. BUTLER, JR.	/s/ DAVID M. VAHOS
Calvin G. Butler, Jr.	David M. Vahos
Chief Executive Officer	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial
(Principal Executive Officer)	Officer)

/s/ ANDREW W. HOLMES
Andrew W. Holmes
Vice President and Controller
(Principal Accounting Officer)
August 2, 2018

Table of Contents

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

/s/ DAVID M. VELAZQUEZ	/s/ ROBERT M. AIKEN
David M. Velazquez	Robert M. Aiken
President and Chief Executive Officer	Vice President and Controller
(Principal Executive Officer)	(Principal Financial Officer)

/s/ ROBERT M. AIKEN
Robert M. Aiken
Vice President and Controller
(Principal Accounting Officer)
August 2, 2018

Table of Contents

Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.
POTOMAC ELECTRIC POWER COMPANY

/s/ DAVID M. VELAZQUEZ	/s/ ROBERT M. AIKEN
David M. Velazquez	Robert M. Aiken
President and Chief Executive Officer	Vice President and Controller
(Principal Executive Officer)	(Principal Financial Officer)

/s/ ROBERT M. AIKEN
Robert M. Aiken
Vice President and Controller
(Principal Accounting Officer)
August 2, 2018

Table of Contents

Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.
DELMARVA POWER & LIGHT COMPANY

/s/ DAVID M. VELAZQUEZ	/s/ ROBERT M. AIKEN
David M. Velazquez	Robert M. Aiken
President and Chief Executive Officer	Vice President and Controller
(Principal Executive Officer)	(Principal Financial Officer)

/s/ ROBERT M. AIKEN
Robert M. Aiken
Vice President and Controller
(Principal Accounting Officer)
August 2, 2018

Table of Contents

Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.
ATLANTIC CITY ELECTRIC COMPANY

/s/ DAVID M. VELAZQUEZ	/s/ ROBERT M. AIKEN
David M. Velazquez	Robert M. Aiken
President and Chief Executive Officer	Vice President and Controller
(Principal Executive Officer)	(Principal Financial Officer)

/s/ ROBERT M. AIKEN
Robert M. Aiken
Vice President and Controller
(Principal Accounting Officer)
August 2, 2018

309