KEYCORP /NEW/
Form 4
July 01, 2014

FORM 4

Check this box if no longer subject to Section 16. Form 4 or Form 5 obligations may continue. *See* Instruction 1(b).

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

OMB APPROVAL
OMB Number: 3235-0287
Expires: January 31, 2005
Estimated average burden hours per response... 0.5

(Print or Type Responses)

1. Name and Address of Reporting Person *
GILLIS RUTH ANN M
(Last) (First) (Middle)
C/O KEYCORP, 127 PUBLIC SQUARE
(Street)
CLEVELAND, OH 44114
(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
KEYCORP /NEW/ [KEY]

3. Date of Earliest Transaction (Month/Day/Year)
07/01/2014

4. If Amendment, Date Original Filed(Month/Day/Year)

5. Relationship of Reporting Person(s) to Issuer

(Check all applicable)

__X__ Director _____ 10% Owner
_____ Officer (give title below) _____ Other (specify below)

6. Individual or Joint/Group Filing(Check Applicable Line)
_X_ Form filed by One Reporting Person
___ Form filed by More than One Reporting Person

Table I - Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)		4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)			5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
			Code	V	Amount	(A) or (D)	Price			
Common Shares								3,500	D	

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

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SEC 1474 (9-02)

Table II - Derivative Securities Acquired, Disposed of, or Beneficially Owned
(*e.g.*, puts, calls, warrants, options, convertible securities)

1. Title of Derivative Security (Instr. 3)	2. Conversion or Exercise Price of Derivative Security	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if any (Month/Day/Year)	4. Transaction Code (Instr. 8)		5. Number of Derivative Securities Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)		6. Date Exercisable and Expiration Date (Month/Day/Year)		7. Title and Amount of Underlying Securities (Instr. 3 and 4)		8. Price o Derivativ Security (Instr. 5)
				Code	V	(A)	(D)	Date Exercisable	Expiration Date	Title	Amount or Number of Shares	
Deferred Shares	(1)	07/01/2014		A		973		(2)	(2)	Common Shares	973	$ 14.3

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
GILLIS RUTH ANN M C/O KEYCORP 127 PUBLIC SQUARE CLEVELAND, OH 44114	X			

Signatures

Frank P. Esposito POA Ruth Ann M. Gillis	07/01/2014
**Signature of Reporting Person	Date

Explanation of Responses:

* If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).

** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).

(1) Beginning in January 2014, directors may elect to defer the payment of directors' fees into the Director's Deferred Share Sub-Plan to the KeyCorp 2013 Equity Compensation Plan (the "Deferred Share Plan"). The deferred fees are converted into deferred shares, which are the economic equivalent of one common share.

(2) Under the terms of the Deferred Share Plan, payment of the deferred shares has been deferred until the earlier of October 1, 2017 or the death of the participant.

(3) Includes apoproximately 146 dividend-equivalent deferred shares accrued under the Deferred Share Plan in June 2014.

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *see* Instruction 6 for procedure.
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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

—

—

—

—

—

Explanation of Responses:

—

—

Amortization of energy contract assets and liabilities[b]
20

20

—

—

—

—

—

—

—

Nuclear fuel[c]
529

529

—

—

—

—

Explanation of Responses:

—

—

—

ARO accretion[d]
231

229

—

—

—

—

—

—

—

Total depreciation, amortization and accretion
$
2,591

$
1,415

$
419

$

Explanation of Responses:

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.

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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

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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.

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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

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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.

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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.

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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

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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.

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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]			Intersegment revenues	Total Revenues
	Contracts with customers	Other[b]	Total		
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]			Intersegment revenues	Total Revenues
	Contracts with customers	Other[b]	Total		
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.

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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

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(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.

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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

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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.

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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

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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.

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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.

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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

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(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.

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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

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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

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(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.

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

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

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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.

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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

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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.

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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

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	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.

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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.

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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.

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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

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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.

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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

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(All amounts in millions after tax)	Six Months Ended June 30, 2018	Earnings per Diluted Share	2017	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.

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(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

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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.

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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.

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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.

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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.

	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.

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.

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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:

		(in millions)		
	Customer Outages	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

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(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

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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.

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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.

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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

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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.

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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

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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.

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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

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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.

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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

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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

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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)

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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

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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.

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- 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.

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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.

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Generation's supply sources by region are summarized below:

Supply source (GWhs)	Three Months Ended June 30, 2018	2017	Variance	% Change	Six Months Ended June 30, 2018	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.

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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

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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.

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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.

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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.

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Explanation of Responses:

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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.

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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

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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.

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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

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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.

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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.

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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)

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(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.

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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.

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Results of Operations — PECO

	Three Months Ended June 30,		Favorable (Unfavorable) Variance	Six Months Ended June 30,		Favorable (Unfavorable) Variance
	2018	2017		2018	2017	
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.

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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%

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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

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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.

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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.

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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.

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PECO Natural Gas Operating Statistics

Deliveries to Customers (in mmcf)	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	% Change	Weather - Normal % Change	Six Months Ended June 30, 2018	Six Months Ended June 30, 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	As of June 30, 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.

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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.

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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%

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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 Increase (Decrease)			Six Months Ended June 30, 2018 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.

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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

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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.

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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

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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.

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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.

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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 %	Six Months Ended June 30,			Weather - Normal %
	2018	2017	% Change	Change	2018	2017	% Change	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.

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See Note 19 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of Pepco's revenue disaggregation.

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Results of Operations - DPL

	Three Months Ended June 30, 2018	2017	Favorable (Unfavorable) Variance	Six Months Ended June 30, 2018	2017	Favorable (Unfavorable) Variance
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

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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.

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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.

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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.

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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.

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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.

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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 %

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	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.

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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

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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 %

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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.

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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,		Increase (Decrease)	Six Months Ended June 30,		Increase (Decrease)
	2018	2017		2018	2017	
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.

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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.

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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.

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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

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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.

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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.

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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

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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

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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)

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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.

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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

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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.

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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

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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.

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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.

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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.

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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.

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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

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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.

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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.

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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

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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).

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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.

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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.

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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

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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

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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

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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.

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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.

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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

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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

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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

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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

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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

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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

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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

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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 (Principal Executive Officer)	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)

/s/ ANDREW W. HOLMES
Andrew W. Holmes
Vice President and Controller
(Principal Accounting Officer)
August 2, 2018

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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

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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

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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

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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

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