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

FORM 10-Q

[X] **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended **September 30, 2017**

or

[ ] **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ____________________ to ____________________

Commission File Number: **001-5532-99**

PORTLAND GENERAL ELECTRIC COMPANY

(Exact name of registrant as specified in its charter)

Oregon	**93-0256820**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

121 SW Salmon Street
Portland, Oregon 97204
(503) 464-8000
(Address of principal executive offices, including zip code, and registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. [x] Yes [ ] No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
[x] Yes [ ] No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer [x]	Accelerated filer [ ]
Non-accelerated filer [ ]	(Do not check if a smaller reporting company)
	Smaller reporting company [ ]
	Emerging growth company [ ]

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). [ ] Yes [x] No

Number of shares of common stock outstanding as of October 17, 2017 is 89,092,325 shares.

PORTLAND GENERAL ELECTRIC COMPANY
FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2017

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DEFINITIONS

The following abbreviations and acronyms are used throughout this document:

Abbreviation or Acronym	Definition
AFDC	Allowance for funds used during construction
AUT	Annual Power Cost Update Tariff
Boardman	Boardman coal-fired generating plant
Carty	Carty natural gas-fired generating plant
Colstrip	Colstrip Units 3 and 4 coal-fired generating plant
CWIP	Construction work-in-progress
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FMBs	First Mortgage Bonds
GAAP	Accounting principles generally accepted in the United States of America
GRC	General Rate Case
IRP	Integrated Resource Plan
Moody's	Moody's Investors Service
MW	Megawatts
MWa	Average megawatts
MWh	Megawatt hours
NVPC	Net Variable Power Costs
OCEP	Oregon Clean Electricity and Coal Transition Plan
OPUC	Public Utility Commission of Oregon
PCAM	Power Cost Adjustment Mechanism
RPS	Renewable Portfolio Standard
S&P	S&P Global Ratings
SEC	United States Securities and Exchange Commission
Trojan	Trojan nuclear power plant

PART I — FINANCIAL INFORMATION

Item 1. Financial Statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
AND COMPREHENSIVE INCOME
(Dollars in millions, except per share amounts)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	**2016**	**2017**	**2016**
Revenues, net	**$ 515**	**$ 484**	**$ 1,494**	**$ 1,399**
Operating expenses:				
Purchased power and fuel	184	180	443	455
Generation, transmission and distribution	73	69	235	199
Administrative and other	64	63	197	185
Depreciation and amortization	87	79	257	244
Taxes other than income taxes	30	29	94	89
Total operating expenses	438	420	1,226	1,172
Income from operations	**77**	**64**	**268**	**227**
Interest expense, net	30	28	90	82
Other income:				
Allowance for equity funds used during construction	4	4	9	19
Miscellaneous income, net	2	—	4	—
Other income, net	6	4	13	19
Income before income tax expense	**53**	**40**	**191**	**164**
Income tax expense	13	6	46	32
Net income and Comprehensive income	**$ 40**	**$ 34**	**$ 145**	**$ 132**
Weighted-average shares outstanding—basic and diluted (in thousands)	89,065	88,921	89,044	88,885
Earnings per share—basic and diluted	$ 0.44	$ 0.38	$ 1.62	$ 1.49
Dividends declared per common share	$ 0.34	$ 0.32	$ 1.00	$ 0.94

See accompanying notes to condensed consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Dollars in millions)
(Unaudited)

	September 30, 2017	December 31, 2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 89	$ 6
Accounts receivable, net	151	155
Unbilled revenues	71	107
Inventories	70	82
Regulatory assets—current	42	36
Other current assets	43	77
Total current assets	**466**	**463**
Electric utility plant, net	6,638	6,434
Regulatory assets—noncurrent	526	498
Nuclear decommissioning trust	41	41
Non-qualified benefit plan trust	37	34
Other noncurrent assets	51	57
Total assets	**$ 7,759**	**$ 7,527**

See accompanying notes to condensed consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS, continued
(Dollars in millions)
(Unaudited)

	September 30, 2017	December 31, 2016
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 100	$ 129
Liabilities from price risk management activities—current	43	44
Current portion of long-term debt	100	150
Accrued expenses and other current liabilities	248	254
Total current liabilities	**491**	**577**
Long-term debt, net of current portion	2,277	2,200
Regulatory liabilities—noncurrent	1,002	958
Deferred income taxes	701	669
Unfunded status of pension and postretirement plans	288	281
Liabilities from price risk management activities—noncurrent	150	125
Asset retirement obligations	166	161
Non-qualified benefit plan liabilities	105	105
Other noncurrent liabilities	177	107
Total liabilities	**5,357**	**5,183**
Commitments and contingencies (see notes)		
Equity:		
Portland General Electric Company shareholders' equity:		
Preferred stock, no par value, 30,000,000 shares authorized; none issued and outstanding as of September 30, 2017 and December 31, 2016	—	—
Common stock, no par value, 160,000,000 shares authorized; 89,091,955 and 88,946,704 shares issued and outstanding as of September 30, 2017 and December 31, 2016, respectively	1,204	1,201
Accumulated other comprehensive loss	(7)	(7)
Retained earnings	1,205	1,150
Total equity	**2,402**	**2,344**
Total liabilities and equity	**$ 7,759**	**$ 7,527**

See accompanying notes to condensed consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)
(Unaudited)

	Nine Months Ended September 30,	
	2017	**2016**
Cash flows from operating activities:		
Net income	$ 145	$ 132
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	257	244
Deferred income taxes	35	18
Pension and other postretirement benefits	19	21
Allowance for equity funds used during construction	(9)	(19)
Decoupling mechanism deferrals, net of amortization	(15)	(4)
Other non-cash income and expenses, net	18	12
Changes in working capital:		
Decrease in accounts receivable and unbilled revenues	40	53
Decrease in inventories	12	1
Decrease in margin deposits, net	4	25
Increase in accounts payable and accrued liabilities	14	31
Other working capital items, net	20	12
Other, net	(21)	(29)
Net cash provided by operating activities	**519**	**497**
Cash flows from investing activities:		
Capital expenditures	(369)	(454)
Sales of Nuclear decommissioning trust securities	14	17
Purchases of Nuclear decommissioning trust securities	(12)	(16)
Other, net	(2)	(1)
Net cash used in investing activities	**(369)**	**(454)**

See accompanying notes to condensed consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS, continued
(In millions)
(Unaudited)

	Nine Months Ended September 30,	
	2017	**2016**
Cash flows from financing activities:		
Proceeds from issuance of long-term debt	75	265
Payments on long-term debt	(50)	(133)
Change in short-term debt	—	(6)
Dividends paid	(87)	(82)
Other	(5)	(3)
Net cash (used in) provided by financing activities	**(67)**	**41**
Increase in cash and cash equivalents	**83**	**84**
Cash and cash equivalents, beginning of period	**6**	**4**
Cash and cash equivalents, end of period	**$ 89**	**$ 88**
Supplemental cash flow information is as follows:		
Cash paid for interest, net of amounts capitalized	$ 68	$ 61
Cash paid for income taxes	16	12
Non-cash investing and financing activities:		
Assets obtained under capital lease	73	57

See accompanying notes to condensed consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

NOTE 1: BASIS OF PRESENTATION

Nature of Business

Portland General Electric Company (PGE or the Company) is a single, vertically integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the State of Oregon. The Company also participates in the wholesale market by purchasing and selling electricity and natural gas in an effort to obtain reasonably-priced power for its retail customers. PGE operates as a single segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis. The Company's corporate headquarters is located in Portland, Oregon and its approximately 4,000 square mile, state-approved service area allocation, located entirely within the State of Oregon, encompasses 51 incorporated cities, of which Portland and Salem are the largest. As of September 30, 2017, PGE served approximately 873,000 retail customers with a service area population of approximately 1.9 million, comprising approximately 46% of the state's population.

Condensed Consolidated Financial Statements

These condensed consolidated financial statements have been prepared pursuant to the rules and regulations of the United States Securities and Exchange Commission (SEC). Certain information and note disclosures normally included in financial statements prepared in conformity with accounting principles generally accepted in the United States of America (GAAP) have been condensed or omitted pursuant to such regulations, although PGE believes that the disclosures provided are adequate to make the interim information presented not misleading.

To conform to the 2017 presentation, PGE has reclassified Decoupling mechanism deferrals, net of amortization of $(4) million from Other non-cash income and expenses, net within the operating activities section of the condensed consolidated statement of cash flows for the nine months ended September 30, 2016.

The financial information included herein for the three and nine months ended September 30, 2017 and 2016 is unaudited; however, such information reflects all adjustments, consisting of normal recurring adjustments, that are, in the opinion of management, necessary for a fair presentation of the condensed consolidated financial position, condensed consolidated income and comprehensive income, and condensed consolidated cash flows of the Company for these interim periods. The financial information as of December 31, 2016 is derived from the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2016, included in Item 8 of PGE's Annual Report on Form 10-K, filed with the SEC on February 17, 2017, which should be read in conjunction with such condensed consolidated financial statements.

Comprehensive Income

PGE had an immaterial amount of Other comprehensive income during the three and nine month periods ended September 30, 2017 and 2016.

Use of Estimates

The preparation of condensed consolidated financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosures of gain or loss contingencies, as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results experienced by the Company could differ materially from those estimates.

Certain costs are estimated for the full year and allocated to interim periods based on estimates of operating time expired, benefit received, or activity associated with the interim period; accordingly, such costs may not be reflective of amounts to be recognized for a full year. Due to seasonal fluctuations in electricity sales, as well as the price of wholesale energy and natural gas, interim financial results do not necessarily represent those to be expected for the year.

Recent Accounting Pronouncements

Accounting Standards Update (ASU) 2014-09, *Revenue from Contracts with Customers* (Topic 606) (ASU 2014-09), creates a new Topic 606 and supersedes the revenue recognition requirements in Topic 605, *Revenue Recognition*, and most industry-specific guidance throughout the Industry Topics of the Codification. ASU 2014-09 provides a five-step analysis of transactions to determine when and how revenue is recognized that consists of: i) identify the contract with the customer; ii) identify the performance obligations in the contract; iii) determine the transaction price; iv) allocate the transaction price to the performance obligations; and v) recognize revenue when or as each performance obligation is satisfied. Companies can transition to the requirements of this ASU either retrospectively (full retrospective method) or as a cumulative-effect adjustment as of the effective date (modified retrospective method), which is January 1, 2018 for calendar year-end public entities. The Company plans to elect the modified retrospective transition method for implementation. PGE does not anticipate any material changes to its revenue policy for tariff-based revenues, which comprises a majority of PGE's retail revenues, as performance obligations are expected to be satisfied in a similar recognition pattern. PGE continues to evaluate the impacts the new guidance may have on its consolidated financial position, consolidated results of operations, and consolidated cash flows, particularly related to certain matters of presentation of alternative revenue programs (such as decoupling), wholesale, and other operating revenue contracts.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)* which supersedes the current lease accounting requirements for lessees and lessors within *Topic 840, Leases.* Pursuant to the new standard, lessees will be required to recognize all leases, including operating leases, on the balance sheet and record corresponding right-of-use assets and lease liabilities. Accounting for lessors is substantially unchanged from current accounting principles. Lessees will be required to classify leases as either finance leases or operating leases. Initial balance sheet measurement is similar for both types of leases; however, expense recognition and amortization of right-of-use assets will differ. Operating leases will reflect lease expense on a straight-line basis, while finance leases will result in the separate presentation of interest expense on the lease liability (as calculated using the effective interest method) and amortization expense of the right-of-use asset. Quantitative and qualitative disclosures will also be required surrounding significant judgments made by management. The provisions of this pronouncement are effective for calendar year-end, public entities on January 1, 2019 and must be applied on a modified retrospective basis as of the beginning of the earliest comparative period presented. The new standard also provides reporting entities the option to elect a package of practical expedients for existing leases that commenced before the effective date. Early adoption is permitted. The Company is in the process of evaluating the impact to its consolidated financial position, consolidated results of operations, and consolidated cash flows of the adoption of ASU 2016-02.

In March 2017, the FASB issued ASU 2017-07, *Compensation-Retirement Benefits (Topic 715), Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* (ASU 2017-07). Pursuant to this ASU, only the service cost component of net periodic pension and postretirement benefit costs will be eligible for capitalization and should be applied on a prospective basis upon implementation. Also, the non-service components are required to be presented in the income statement separately from the service cost component and outside the subtotal of income from operations and should be applied on a retrospective basis upon implementation. For calendar year-end public entities, the update will be effective for annual periods beginning January 1, 2018. The Company does not plan to early adopt. For ratemaking purposes, the Company will continue to be allowed to recover this portion of the non-service costs as a component of rate base, however such amounts will be recorded as

PORTLAND GENERAL ELECTRIC COMPANY
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS, continued
(Unaudited)

Regulatory assets on the Company's condensed consolidated balance sheets, instead of Utility plant, and amortized in a systematic and rational manner and reflected as expense in a line item outside the subtotal of income from operations on the condensed consolidated statements of income and other comprehensive income. PGE estimates the portion of the non-service components of net periodic pension and postretirement benefit costs that is eligible for capitalization for ratemaking purposes, to be $2 million for the twelve month period ending December 31, 2018, and is deemed to have an immaterial impact on the Company's consolidated financial position and consolidated results of operations.

NOTE 2: BALANCE SHEET COMPONENTS

Inventories

PGE's inventories, which are recorded at average cost, consist primarily of materials and supplies for use in operations, maintenance, and capital activities, as well as fuel, which includes natural gas, coal, and oil for use in the Company's generating plants. Periodically, the Company assesses inventory for purposes of determining that inventory is recorded at the lower of average cost or net realizable value.

Other Current Assets

Other current assets consist of the following (in millions):

	September 30, 2017	December 31, 2016
Prepaid expenses	$ 27	$ 48
Assets from price risk management activities	4	18
Margin deposits	4	8
Other	8	3
Other current assets	$ 43	$ 77

Electric Utility Plant, Net

Electric utility plant, net consists of the following (in millions):

	September 30, 2017	December 31, 2016
Electric utility plant	$ 9,766	$ 9,534
Construction work-in-progress	386	213
Total cost	10,152	9,747
Less: accumulated depreciation and amortization	(3,514)	(3,313)
Electric utility plant, net	$ 6,638	$ 6,434

Accumulated depreciation and amortization in the table above includes accumulated amortization related to intangible assets of $288 million and $257 million as of September 30, 2017 and December 31, 2016, respectively. Amortization expense related to intangible assets was $11 million for the three months ended September 30, 2017 and 2016, and $34 million and $33 million for the nine months ended September 30, 2017 and 2016, respectively. The Company's intangible assets primarily consist of computer software development and hydro licensing costs.

PORTLAND GENERAL ELECTRIC COMPANY
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS, continued
(Unaudited)

Regulatory Assets and Liabilities

Regulatory assets and liabilities consist of the following (in millions):

	September 30, 2017		December 31, 2016	
	Current	Noncurrent	Current	Noncurrent
Regulatory assets:				
Price risk management	$ 39	$ 150	$ 26	$ 120
Pension and other postretirement plans	—	225	—	235
Deferred income taxes	—	83	—	86
Debt issuance costs	—	20	—	22
Other	3	48	10	35
Total regulatory assets	$ 42	$ 526	$ 36	$ 498
Regulatory liabilities:				
Asset retirement removal costs	$ —	$ 921	$ —	$ 887
Trojan decommissioning activities	4	—	18	—
Asset retirement obligations	—	52	—	49
Other	16	29	33	22
Total regulatory liabilities	$ 20 *	$ 1,002	$ 51 *	$ 958

* Included in Accrued expenses and other current liabilities in the condensed consolidated balance sheets.

Accrued Expenses and Other Current Liabilities

Accrued expenses and other current liabilities consist of the following (in millions):

	September 30, 2017	December 31, 2016
Accrued employee compensation and benefits	$ 51	$ 52
Accrued taxes payable	46	25
Accrued interest payable	40	25
Accrued dividends payable	31	30
Regulatory liabilities—current	20	51
Other	60	71
Total accrued expenses and other current liabilities	$ 248	$ 254

Credit Facilities

As of September 30, 2017, PGE had a $500 million revolving credit facility scheduled to expire in November 2020.

Pursuant to the terms of the agreement, the revolving credit facility may be used for general corporate purposes, as backup for commercial paper borrowings, and to permit the issuance of standby letters of credit. PGE may borrow for one, two, three, or six months at a fixed interest rate established at the time of the borrowing, or at a variable interest rate for any period up to the then remaining term of the credit facility. During the first quarter of 2017, PGE exercised one of the two one-year extensions available under the terms of the credit facility. Such action resulted in an updated expiration date of November 2020. The facility also contains a provision that requires annual fees based on PGE's unsecured credit ratings, and contains customary covenants and default provisions, including a requirement that limits consolidated indebtedness, as defined in the agreement, to 65% of total capitalization. As of September 30, 2017, PGE was in compliance with this covenant with a 51.3% debt-to-total capital ratio.

The Company has a commercial paper program under which it may issue commercial paper for terms of up to 270 days, limited to the unused amount of credit under the revolving credit facility.

PGE classifies any borrowings under the revolving credit facility and outstanding commercial paper as Short-term debt on the condensed consolidated balance sheets.

Under the revolving credit facility, as of September 30, 2017, since PGE had no borrowings outstanding, and no commercial paper or letters of credit issued, the aggregate unused available credit capacity under the revolving credit facility was $500 million.

In addition, PGE has four letter of credit facilities under which the Company can request letters of credit for original terms not to exceed one year. These facilities provide a total capacity of $220 million. The issuance of such letters of credit is subject to the approval of the issuing institution. Under these facilities, letters of credit for a total of $54 million were outstanding as of September 30, 2017. Letters of credit issued are not reflected on the Company's condensed consolidated balance sheets.

Pursuant to an order issued by the Federal Energy Regulatory Commission (FERC), the Company is authorized to issue short-term debt in an aggregate amount of up to $900 million through February 6, 2018.

Long-term Debt

On August 2, 2017, PGE entered into a bond purchase agreement to issue First Mortgage Bonds (FMBs) in the amount of $225 million at an interest rate of 3.98%. The first tranche of $75 million, with a maturity in 2048, was issued on August 2, 2017. The second tranche of $150 million, with a maturity in 2047, is expected to be issued and funded on or about November 21, 2017.

In May 2016, PGE entered into an unsecured credit agreement with certain financial institutions, under which the Company had the opportunity to obtain three separate term loans in an aggregate principal amount of up to $200 million by October 31, 2016. Under the agreement, PGE obtained three separate loans totaling $150 million. On August 21, 2017, the Company repaid one of the loans in the amount of $50 million. The credit agreement expires November 30, 2017, at which time any amounts outstanding under the term loans become due and payable.

The term loan interest rates on the remaining loans are set at the beginning of the interest period for periods of one, three, or six months, as selected by PGE, and are based on the London Interbank Offered Rate plus 63 basis points, and was 1.9% as of September 30, 2017, with no other fees.

Upon the occurrence of certain events of default, the Company's obligations under the credit agreement may be accelerated. Such events of default include payment defaults to lenders under the credit agreement, covenant defaults, and other customary defaults for financings of this type.

Defined Benefit Pension Plan Costs

Components of net periodic benefit cost under the defined benefit pension plan are as follows (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Service cost	$ 4	$ 4	$ 12	$ 12
Interest cost	8	9	25	25
Expected return on plan assets	(10)	(10)	(30)	(30)
Amortization of net actuarial loss	3	3	9	11
Net periodic benefit cost	$ 5	$ 6	$ 16	$ 18

NOTE 3: FAIR VALUE OF FINANCIAL INSTRUMENTS

PGE determines the fair value of financial instruments, both assets and liabilities recognized and not recognized in the Company's condensed consolidated balance sheets, for which it is practicable to estimate fair value as of September 30, 2017 and December 31, 2016, and then classifies these financial assets and liabilities based on a fair value hierarchy that is applied to prioritize the inputs to the valuation techniques used to measure fair value. The three levels of the fair value hierarchy and application to the Company are discussed below.

Level 1 Quoted prices are available in active markets for identical assets or liabilities as of the measurement date.

Level 2 Pricing inputs include those that are directly or indirectly observable in the marketplace as of the measurement date.

Level 3 Pricing inputs include significant inputs that are unobservable for the asset or liability.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy. Assets measured at fair value using net asset value (NAV) as a practical expedient are not categorized in the fair value hierarchy; instead these assets are listed in the totals of the fair value hierarchy to permit the reconciliation to amounts presented in the financial statements.

PGE recognizes transfers between levels in the fair value hierarchy as of the end of the reporting period for all its financial instruments. Changes to market liquidity conditions, the availability of observable inputs, or changes in the economic structure of a security marketplace may require transfer of the securities between levels. There were no significant transfers between levels during the three and nine month periods ended September 30, 2017 and 2016, except those presented in this note.

PORTLAND GENERAL ELECTRIC COMPANY
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS, continued
(Unaudited)

The Company’s financial assets and liabilities whose values were recognized at fair value are as follows by level within the fair value hierarchy (in millions):

	As of September 30, 2017				
	Level 1	Level 2	Level 3	Other[2]	Total
Assets:					
Nuclear decommissioning trust: [1]					
Debt securities:					
Domestic government	$ 3	$ 8	$ —	$ —	$ 11
Corporate credit	—	7	—	—	7
Money market funds measured at NAV [2]	—	—	—	23	23
Non-qualified benefit plan trust: [3]					
Money market funds	2	—	—	—	2
Equity securities—domestic	6	—	—	—	6
Debt securities—domestic government	1	—	—	—	1
Collective trust—domestic equity measured at NAV [2]	—	—	—	—	—
Assets from price risk management activities: [1] [4]					
Electricity	—	3	—	—	3
Natural gas	—	1	—	—	1
	$ 12	$ 19	$ —	$ 23	$ 54
Liabilities from price risk management activities: [1] [4]					
Electricity	$ —	$ 3	$ 140	$ —	$ 143
Natural gas	—	37	13	—	50
	$ —	$ 40	$ 153	$ —	$ 193

(1) Activities are subject to regulation, with certain gains and losses deferred pursuant to regulatory accounting and included in Regulatory assets or Regulatory liabilities as appropriate.
(2) Assets are measured at NAV as a practical expedient and not subject to hierarchy level classification disclosure.
(3) Excludes insurance policies of $28 million, which are recorded at cash surrender value.
(4) For further information, see Note 4, Price Risk Management.

PORTLAND GENERAL ELECTRIC COMPANY
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS, continued
(Unaudited)

	As of December 31, 2016				
	Level 1	Level 2	Level 3	Other [2]	Total
Assets:					
Nuclear decommissioning trust: [1]					
Debt securities:					
Domestic government	$ 2	$ 10	$ —	$ —	$ 12
Corporate credit	—	8	—	—	8
Money market funds measured at NAV [2]	—	—	—	21	21
Non-qualified benefit plan trust: [3]					
Money market funds	1	—	—	—	1
Equity securities—domestic	4	—	—	—	4
Debt securities—domestic government	1	—	—	—	1
Collective trust—domestic equity measured at NAV [2]	—	—	—	2	2
Assets from price risk management activities: [1] [4]					
Electricity	—	6	1	—	7
Natural gas	—	15	1	—	16
	$ 8	$ 39	$ 2	$ 23	$ 72
Liabilities from price risk management activities: [1] [4]					
Electricity	$ —	$ 6	$ 112	$ —	$ 118
Natural gas	—	42	9	—	51
	$ —	$ 48	$ 121	$ —	$ 169

(1) Activities are subject to regulation, with certain gains and losses deferred pursuant to regulatory accounting and included in Regulatory assets or Regulatory liabilities as appropriate.
(2) Assets are measured at NAV as a practical expedient and not subject to hierarchy level classification disclosure.
(3) Excludes insurance policies of $26 million, which are recorded at cash surrender value.
(4) For further information, see Note 4, Price Risk Management.

Trust assets held in the Nuclear decommissioning and Non-qualified benefit plan (NQ Plan) trusts are recorded at fair value in PGE's condensed consolidated balance sheets and invested in securities that are exposed to interest rate, credit, and market volatility risks. These assets are classified within Level 1, 2, or 3 based on the following factors:

Debt securities—PGE invests in highly-liquid United States treasury securities to support the investment objectives of the trusts. These domestic government securities are classified as Level 1 in the fair value hierarchy due to the availability of quoted prices for identical assets in an active market as of the measurement date.

Assets classified as Level 2 in the fair value hierarchy include domestic government debt securities, such as municipal debt, and corporate credit securities. Prices are determined by evaluating pricing data such as broker quotes for similar securities and adjusted for observable differences. Significant inputs used in valuation models generally include benchmark yields and issuer spreads. The external credit rating, coupon rate, and maturity of each security are considered in the valuation, as applicable.

Equity securities—Equity mutual fund and common stock securities are classified as Level 1 in the fair value hierarchy due to the availability of quoted prices for identical assets in an active market as of the measurement date. Principal markets for equity prices include published exchanges such as NASDAQ and the New York Stock Exchange.

Money market funds—PGE invests in money market funds that seek to maintain a stable net asset value. These funds invest in high-quality, short-term, diversified money market instruments, short-term treasury bills, federal agency securities, certificates of deposits, and commercial paper. The Company believes the redemption value of these funds is likely to be the fair value, which is represented by the net asset value. Redemption is permitted daily without written notice.

Common and collective trust funds—PGE invests in common and collective trust funds that invest in equity securities. The Company believes the redemption value of these funds is likely to be the fair value, which is represented by the net asset value as a practical expedient. A majority of the funds provide for daily liquidity with appropriate written notice. One fund allows for withdrawal from all accounts as of the last day on each calendar month, with at least 10 days' prior written notice, and provides for a 95% payment to be made within 30 days, and the balance to be paid after the annual fund audit is complete. Common and collective trusts are not classified in the fair value hierarchy as they are valued at NAV as a practical expedient.

Assets and liabilities from price risk management activities are recorded at fair value in PGE's condensed consolidated balance sheets and consist of derivative instruments entered into by the Company to manage its exposure to commodity price risk and foreign currency exchange rate risk, and reduce volatility in net variable power costs (NVPC) for the Company's retail customers. For additional information regarding these assets and liabilities, see Note 4, Price Risk Management.

For those assets and liabilities from price risk management activities classified as Level 2, fair value is derived using present value formulas that utilize inputs such as forward commodity prices and interest rates. Substantially all of these inputs are observable in the marketplace throughout the full term of the instrument, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include commodity forwards, futures, and swaps.

Assets and liabilities from price risk management activities classified as Level 3 consist of instruments for which fair value is derived using one or more significant inputs that are not observable for the entire term of the instrument. These instruments consist of longer term commodity forwards, futures, and swaps.

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Quantitative information regarding the significant, unobservable inputs used in the measurement of Level 3 assets and liabilities from price risk management activities is presented below:

Commodity Contracts	Fair Value: Assets	Fair Value: Liabilities	Valuation Technique	Significant Unobservable Input	Price per Unit: Low	Price per Unit: High	Price per Unit: Weighted Average
	(in millions)						
As of September 30, 2017:							
Electricity physical forwards	$ —	$ 140	Discounted cash flow	Electricity forward price (per MWh)	$ 8.20	$ 37.15	$ 28.36
Natural gas financial swaps	—	13	Discounted cash flow	Natural gas forward price (per Decatherm)	1.59	3.22	2.07
Electricity financial futures	—	—	Discounted cash flow	Electricity forward price (per MWh)	8.20	29.50	23.05
	$ —	$ 153					
As of December 31, 2016:							
Electricity physical forwards	$ —	$ 112	Discounted cash flow	Electricity forward price (per MWh)	$ 14.25	$ 54.73	$ 38.18
Natural gas financial swaps	1	9	Discounted cash flow	Natural gas forward price (per Decatherm)	1.85	4.92	2.64
Electricity financial futures	1	—	Discounted cash flow	Electricity forward price (per MWh)	8.57	33.60	25.10
	$ 2	$ 121					

The significant unobservable inputs used in the Company’s fair value measurement of price risk management assets and liabilities are long-term forward prices for commodity derivatives. For shorter term contracts, PGE employs the mid-point of the bid-ask spread of the market and these inputs are derived using observed transactions in active markets, as well as historical experience as a participant in those markets. These price inputs are validated against independent market data from multiple sources. For certain long-term contracts, observable, liquid market transactions are not available for the duration of the delivery period. In such instances, the Company uses internally-developed price curves, which derive longer term prices and utilize observable data when available. When not available, regression techniques are used to estimate unobservable future prices. In addition, changes in the fair value measurement of price risk management assets and liabilities are analyzed and reviewed on a quarterly basis by the Company.

The Company’s Level 3 assets and liabilities from price risk management activities are sensitive to market price changes in the respective underlying commodities. The significance of the impact is dependent upon the magnitude of the price change and PGE’s position as either the buyer or seller under the contract. Sensitivity of the fair value measurements to changes in the significant unobservable inputs is as follows:

Significant Unobservable Input	Position	Change to Input	Impact on Fair Value Measurement
Market price	Buy	Increase (decrease)	Gain (loss)
Market price	Sell	Increase (decrease)	Loss (gain)

Changes in the fair value of net liabilities from price risk management activities (net of assets from price risk management activities) classified as Level 3 in the fair value hierarchy were as follows (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Balance as of the beginning of the period	153	158	$ 119	$ 119
Net realized and unrealized (gains)/losses*	(1)	—	34	40
Transfers out of Level 3 to Level 2	1	2	—	1
Balance as of the end of the period	$ 153	$ 160	$ 153	$ 160

* Both realized and unrealized (gains)/losses, of which the unrealized portion is fully offset by the effects of regulatory accounting until settlement of the underlying transactions, are recorded in Purchased power and fuel expense in the condensed consolidated statements of income.

Transfers into Level 3 occur when significant inputs used to value the Company's derivative instruments become less observable, such as a delivery location becoming significantly less liquid. During the three and nine months ended September 30, 2017 and 2016, there were no transfers into Level 3 from Level 2. Transfers out of Level 3 occur when the significant inputs become more observable, such as when the time between the valuation date and the delivery term of a transaction becomes shorter. PGE records transfers in and transfers out of Level 3 at the end of the reporting period for all of its derivative instruments.

Transfers from Level 2 to Level 1 for the Company's price risk management assets and liabilities do not occur, as quoted prices are not available for identical instruments. As such, the Company's assets and liabilities from price risk management activities mature and settle as Level 2 fair value measurements.

Long-term debt is recorded at amortized cost in PGE's condensed consolidated balance sheets. The fair value of the Company's FMBs and Pollution Control Revenue Bonds is classified as a Level 2 fair value measurement and is estimated based on the quoted market prices for the same or similar issues or on the current rates offered to PGE for debt of similar remaining maturities. The fair value of PGE's unsecured term bank loans was classified as a Level 3 fair value measurement and was estimated based on the terms of the loans and the Company's creditworthiness. The significant unobservable inputs to the Level 3 fair value measurement included the interest rate and the length of the loan. The estimated fair value of the Company's unsecured term bank loans approximated their carrying value.

As of September 30, 2017, the carrying amount of PGE's long-term debt was $2,377 million, net of $9 million of unamortized debt expense, and its estimated aggregate fair value was $2,763 million, consisting of $2,663 million and $100 million classified as Level 2 and Level 3, respectively, in the fair value hierarchy.

As of December 31, 2016, the carrying amount of PGE's long-term debt was $2,350 million, net of $11 million of unamortized debt expense, and its estimated aggregate fair value was $2,693 million, consisting of $2,543 million and $150 million classified as Level 2 and Level 3, respectively, in the fair value hierarchy.

NOTE 4: PRICE RISK MANAGEMENT

PGE participates in the wholesale marketplace in order to balance its supply of power, which consists of its own generation combined with wholesale market transactions, to meet the needs of its retail customers, manage risk, and administer its existing long-term wholesale contracts. Such activities include purchases and sales of both power and fuel resulting from economic dispatch decisions for Company-owned generation resources. As a result of this ongoing business activity, PGE is exposed to commodity price risk and foreign currency exchange rate risk, from which changes in prices and/or rates may affect the Company's financial position, results of operations, or cash flows.

PGE utilizes derivative instruments to manage its exposure to commodity price risk and foreign currency rate risk in order to reduce volatility in NVPC for its retail customers. Such derivative instruments may include forward, futures, swaps, and option contracts, which are recorded at fair value on the condensed consolidated balance sheets, for electricity, natural gas, and foreign currency, with changes in fair value recorded in the condensed consolidated statements of income. In accordance with the ratemaking and cost recovery processes authorized by the Public Utility Commission of Oregon (OPUC), the Company recognizes a regulatory asset or liability to defer the gains and losses from derivative instruments until settlement of the associated derivative instrument. PGE may designate certain derivative instruments as cash flow hedges or may use derivative instruments as economic hedges. The Company does not engage in trading activities for non-retail purposes.

PGE's Assets and Liabilities from price risk management activities consist of the following (in millions):

	September 30, 2017	December 31, 2016
Current assets:		
Commodity contracts:		
Electricity	$ 3	$ 6
Natural gas	1	12
Total current derivative assets	4 (1)	18 (1)
Noncurrent assets:		
Commodity contracts:		
Electricity	—	1
Natural gas	—	4
Total noncurrent derivative assets	—	5 (2)
Total derivative assets not designated as hedging instruments	$ 4	$ 23
Total derivative assets	$ 4	$ 23
Current liabilities:		
Commodity contracts:		
Electricity	$ 11	$ 12
Natural gas	32	32
Total current derivative liabilities	43	44
Noncurrent liabilities:		
Commodity contracts:		
Electricity	132	106
Natural gas	18	19
Total noncurrent derivative liabilities	150	125
Total derivative liabilities not designated as hedging instruments	$ 193	$ 169
Total derivative liabilities	$ 193	$ 169

(1) Included in Other current assets on the condensed consolidated balance sheets.
(2) Included in Other noncurrent assets on the condensed consolidated balance sheets.

PGE's net purchase volumes related to its Assets and Liabilities from price risk management activities resulting from its derivative transactions, which are expected to deliver or settle through 2035, were as follows (in millions):

	September 30, 2017		December 31, 2016	
Commodity contracts:				
Electricity	6	MWh	8	MWh
Natural gas	114	Decatherms	107	Decatherms
Foreign currency	$ 21	Canadian	$ 22	Canadian

PGE has elected to report gross on the condensed consolidated balance sheets the positive and negative exposures resulting from derivative instruments pursuant to agreements that meet the definition of a master netting arrangement. In the case of default on, or termination of, any contract under the master netting arrangements, these agreements provide for the net settlement of all related contractual obligations with a given counterparty through a single payment. These types of transactions may include non-derivative instruments, derivatives qualifying for scope exceptions, receivables and payables arising from settled positions, and other forms of non-cash collateral, such as letters of credit. As of September 30, 2017, and December 31, 2016, gross amounts included as Price risk management liabilities subject to master netting agreements were $143 million and $115 million, respectively, for which PGE posted collateral of $11 million, which consisted entirely of letters of credit. As of September 30, 2017, of the gross amounts recognized, $140 million was for electricity and $3 million was for natural gas compared to $112 million for electricity and $3 million for natural gas recognized as of December 31, 2016.

Net realized and unrealized losses (gains) on derivative transactions not designated as hedging instruments are classified in Purchased power and fuel in the condensed consolidated statements of income and were as follows (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Commodity contracts:				
Electricity	$ 1	$ 8	$ 50	$ 60
Natural Gas	7	10	48	(14)
Foreign currency exchange	—	—	(1)	(1)

Net unrealized and certain net realized losses (gains) presented in the table above are offset within the condensed consolidated statements of income by the effects of regulatory accounting. None of the net losses recognized in Net income for the three month period ended September 30, 2017 was offset, while net losses of $20 million were offset for the three month period ended September 30, 2016. Net losses of $65 million and $36 million have been offset for the nine month periods ended September 30, 2017 and 2016, respectively.

Assuming no changes in market prices and interest rates, the following table indicates the year in which the net unrealized loss recorded as of September 30, 2017 related to PGE's derivative activities would become realized as a result of the settlement of the underlying derivative instrument (in millions):

	2017	2018	2019	2020	2021	Thereafter	Total
Commodity contracts:							
Electricity	$ —	$ 9	$ 8	$ 8	$ 8	$ 107	$ 140
Natural gas	14	22	9	4	—	—	49
Net unrealized loss	$ 14	$ 31	$ 17	$ 12	$ 8	$ 107	$ 189

PGE's secured and unsecured debt is currently rated at investment grade by Moody's Investors Service (Moody's) and S&P Global Ratings (S&P). Should Moody's and/or S&P reduce their rating on PGE's unsecured debt to below investment grade, the Company could be subject to requests by certain wholesale counterparties to post additional performance assurance collateral, in the form of cash or letters of credit, based on total portfolio positions with each of those counterparties. Certain other counterparties would have the right to terminate their agreements with the Company.

The aggregate fair value of derivative instruments with credit-risk-related contingent features that were in a liability position as of September 30, 2017 was $191 million, for which PGE has posted $18 million in collateral, consisting entirely of letters of credit. If the credit-risk-related contingent features underlying these agreements were triggered at September 30, 2017, the cash requirement to either post as collateral or settle the instruments immediately would have been $190 million. Cash collateral for derivative instruments is classified as Margin deposits included in Other current assets on the Company's condensed consolidated balance sheet.

Counterparties representing 10% or more of Assets and Liabilities from price risk management activities were as follows:

	September 30, 2017	December 31, 2016
Assets from price risk management activities:		
Counterparty A	53%	22%
Counterparty B	3	17
Counterparty C	1	12
Counterparty D	15	—%
Counterparty E	10	—%
	82%	51%
Liabilities from price risk management activities:		
Counterparty F	72%	66%
	72%	66%

See Note 3, Fair Value of Financial Instruments, for additional information concerning the determination of fair value for the Company's Assets and Liabilities from price risk management activities.

NOTE 5: EARNINGS PER SHARE

Basic earnings per share are computed based on the weighted average number of common shares outstanding during the period. Diluted earnings per share are computed using the weighted average number of common shares outstanding and the effect of dilutive potential common shares outstanding during the period using the treasury stock method. Potential common shares consist of: i) employee stock purchase plan shares; and ii) contingently issuable time-based and performance-based restricted stock units, along with associated dividend equivalent rights. Unvested performance-based restricted stock units and associated dividend equivalent rights are included in dilutive potential common shares only after the performance criteria have been met.

For the three and nine month periods ended September 30, 2017, unvested performance-based restricted stock units and related dividend equivalent rights in the total amount of 267 thousand were excluded from the dilutive calculation because the performance goals had not been met, with 306 thousand excluded for the three and nine month periods ended September 30, 2016.

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Net income is the same for both the basic and diluted earnings per share computations. The denominators of the basic and diluted earnings per share computations are as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Weighted-average common shares outstanding—basic and diluted	89,065	88,921	89,044	88,885

NOTE 6: EQUITY

The activity in equity during the nine months ended September 30, 2017 and 2016 is as follows (dollars in millions):

	Common Stock		Accumulated Other Comprehensive Loss	Retained Earnings	Total
	Shares	Amount			
Balances as of December 31, 2016	88,946,704	$ 1,201	$ (7)	$ 1,150	$ 2,344
Issuances of shares pursuant to equity-based plans	145,251	1	—	—	1
Stock-based compensation	—	2	—	—	2
Dividends declared	—	—	—	(90)	(90)
Net income	—	—	—	145	145
Balances as of September 30, 2017	89,091,955	$ 1,204	$ (7)	$ 1,205	$ 2,402
Balances as of December 31, 2015	88,792,751	$ 1,196	$ (8)	$ 1,070	$ 2,258
Issuances of shares pursuant to equity-based plans	133,875	1	—	—	1
Stock-based compensation	—	2	—	—	2
Dividends declared	—	—	—	(84)	(84)
Other comprehensive income		—	1	—	1
Net income	—	—	—	132	132
Balances as of September 30, 2016	88,926,626	$ 1,199	$ (7)	$ 1,118	$ 2,310

NOTE 7: CONTINGENCIES

PGE is subject to legal, regulatory, and environmental proceedings, investigations, and claims that arise from time to time in the ordinary course of its business. Contingencies are evaluated using the best information available at the time the condensed consolidated financial statements are prepared. Legal costs incurred in connection with loss contingencies are expensed as incurred. The Company may seek regulatory recovery of certain costs that are incurred in connection with such matters, although there can be no assurance that such recovery would be granted.

Loss contingencies are accrued, and disclosed if material, when it is probable that an asset has been impaired or a liability incurred as of the financial statement date and the amount of the loss can be reasonably estimated. If a reasonable estimate of probable loss cannot be determined, a range of loss may be established, in which case the minimum amount in the range is accrued, unless some other amount within the range appears to be a better estimate.

A loss contingency will also be disclosed when it is reasonably possible that an asset has been impaired or a liability incurred if the estimate or range of potential loss is material. If a probable or reasonably possible loss cannot be determined, then the Company: i) discloses an estimate of such loss or the range of such loss, if the Company is able to determine such an estimate; or ii) discloses that an estimate cannot be made and the reasons.

If an asset has been impaired or a liability incurred after the financial statement date, but prior to the issuance of the financial statements, the loss contingency is disclosed, if material, and the amount of any estimated loss is recorded in the subsequent reporting period.

The Company evaluates, on a quarterly basis, developments in such matters that could affect the amount of any accrual, as well as the likelihood of developments that would make a loss contingency both probable and reasonably estimable. The assessment as to whether a loss is probable or reasonably possible, and as to whether such loss or a range of such loss is estimable, often involves a series of complex judgments about future events. Management is often unable to estimate a reasonably possible loss, or a range of loss, particularly in cases in which: i) the damages sought are indeterminate or the basis for the damages claimed is not clear; ii) the proceedings are in the early stages; iii) discovery is not complete; iv) the matters involve novel or unsettled legal theories; v) significant facts are in dispute; vi) a large number of parties are represented (including circumstances in which it is uncertain how liability, if any, will be shared among multiple defendants); or vii) a wide range of potential outcomes exist. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution, including any possible loss, fine, penalty, or business impact.

Carty

In 2013, PGE entered into an agreement (Construction Agreement) with an engineering, procurement, and construction contractor - Abeinsa EPC LLC, Abener Construction Services, LLC, Teyma Construction USA, LLC, and Abeinsa Abener Teyma General Partnership, an affiliate of Abengoa S.A. (collectively, the “Contractor”) - for the construction of the Carty natural gas-fired generating plant (Carty) located in Eastern Oregon. Liberty Mutual Insurance Company and Zurich American Insurance Company (collectively, the “Sureties”) provided a performance bond of $145.6 million (Performance Bond) under the Construction Agreement.

In December 2015, the Company declared the Contractor in default under the Construction Agreement and terminated the Construction Agreement. Following termination of the Construction Agreement, PGE, in consultation with the Sureties, brought on new contractors and construction resumed.

Carty was placed into service on July 29, 2016 and the Company began collecting its revenue requirement in customer prices on August 1, 2016, as authorized by the OPUC, based on the approved cost of $514 million. Actual costs for the construction of Carty exceeded the approved amount and, as of September 30, 2017, PGE has capitalized $637 million to Electric utility plant.

As the final construction cost exceeded the amount authorized by the OPUC, higher interest and depreciation expense than allowed in the Company’s revenue requirement has resulted. These incremental expenses are recognized in the Company's current results of operations, as a deferral for such amounts would not be considered probable of recovery at this time, in accordance with GAAP.

Actual costs do not reflect any offsetting amounts that may be received from the Sureties, pursuant to the Performance Bond. The amounts recorded also exclude $8 million of liens and claims filed for goods and services provided under contracts with the former Contractor that remain in dispute. The Company believes these liens are invalid and is contesting the claims in the courts.

The incremental costs resulted from various matters relating to the resumption of construction activities following the termination of the Construction Agreement, including, among other things, correcting latent defects in work performed by the former Contractor, determining the remaining scope of construction, preparing work plans for contractors, identifying new contractors, negotiating contracts, and procuring additional materials.

Other items contributing to the increase include costs relating to the removal of certain liens filed on the property for goods and services provided under contracts with the former Contractor, and costs to repair equipment damage that resulted from poor storage and maintenance on the part of the former Contractor.

The Company is involved in several litigation proceedings concerning the termination of the construction agreement and the payment obligations of the Sureties. PGE is seeking recovery of incremental construction costs and other damages pursuant to breach of contract claims against the contractor and claims against the Sureties pursuant to the performance bond. The Sureties have denied liability in whole under the Performance Bond.

Various actions relating to this matter have been filed in the U.S. District Court for the District of Oregon (U.S. District Court), in the Ninth Circuit Court of Appeals (Ninth Circuit), and in an arbitration proceeding before the International Chamber of Commerce International Court of Arbitration (ICC arbitration), involving the following:

- A breach of contract claim brought by PGE against the Sureties in U.S. District Court asserting that the Sureties are responsible for the payment of all damages sustained by PGE as a result of the Contractor's breach of contract;
- A claim brought by PGE in U.S. District Court against the Contractor for failure to satisfy its obligations under the Construction Agreement;
- A claim by Abengoa S.A. in the ICC arbitration proceeding alleging that the Company's termination of the Construction Agreement was wrongful and in breach of the agreement terms and did not give rise to any liability of Abengoa S.A.; and
- A claim by the Contractor against PGE in the ICC arbitration proceeding seeking damages of $117 million based on a claim that PGE wrongfully terminated the Construction Agreement and $44 million based on a claim that PGE failed to disclose certain information to the Contractor, in connection with the Contractor's bid submitted pursuant to the Company's request for proposals.

Following various procedural arguments in the ICC arbitration and the U.S. District Court, in July 2017, the Ninth Circuit held that the ICC arbitration had jurisdiction to determine what parties and what claims could be presented in the ICC arbitration. Oral argument before the ICC arbitration is expected to take place in the spring of 2018. The decision of the ICC arbitration is expected to determine the forum in which the above referenced claims will be heard. Further detail on the various proceedings is presented in *Item1. Legal Proceedings* in Part II - Other Information, of this Quarterly Report on Form 10-Q.

In July 2016, the Company requested from the OPUC a regulatory deferral for the recovery of the revenue requirement associated with the incremental capital costs for Carty starting from its in service date to the date that such amounts are approved in a subsequent regulatory proceeding. The Company has requested that the OPUC delay its review of this deferral request until all legal actions with respect to this matter, including PGE's actions against the Sureties, have been resolved.

Any amounts approved by the OPUC for recovery under the deferral filing would be recognized in earnings in the period of such approval, however there is no assurance that such recovery would be granted by the OPUC. The Company believes that costs incurred to date and capitalized in Electric utility plant, net, in the condensed consolidated balance sheet, were prudently incurred. There have been no settlement discussions with regulators related to such costs.

After exhausting all remedies against the aforementioned parties, the Company intends to seek approval to recover any remaining excess amounts in customer prices in a subsequent regulatory proceeding. However, there is no assurance that such recovery would be allowed by the OPUC.

In accordance with GAAP and the Company's accounting policies, any such excess costs may be charged to expense at the time recovery becomes less than probable and a reasonable estimate of the amount of such disallowance can be made. As of the date of this report, the Company has concluded that the likelihood is less than probable that a portion of the cost of Carty will be disallowed for recovery in customer prices. Accordingly, no loss has been recorded to date related to the project.

EPA Investigation of Portland Harbor

A 1997 investigation by the United States Environmental Protection Agency (EPA) of a segment of the Willamette River known as Portland Harbor revealed significant contamination of river sediments. The EPA subsequently included Portland Harbor on the National Priority List pursuant to the federal Comprehensive Environmental Response, Compensation, and Liability Act as a federal Superfund site and listed 69 Potentially Responsible Parties (PRPs). PGE was included among the PRPs as it has historically owned or operated property near the river. In 2008, the EPA requested information from various parties, including PGE, concerning additional properties in or near the original segment of the river under investigation as well as several miles beyond. Subsequently, the EPA has listed additional PRPs, which now number over 100.

The Portland Harbor site remedial investigation (RI) has been completed pursuant to an Administrative Order on Consent between the EPA and several PRPs known as the Lower Willamette Group (LWG), which does not include PGE. The LWG has funded the RI and feasibility study (FS) and has stated that it had incurred $115 million in investigation-related costs. The Company anticipates that such costs will ultimately be allocated to PRPs as a part of the allocation process for remediation costs of the EPA's preferred remedy.

The EPA has finalized the FS, along with the RI, and these documents provided the framework for the EPA to determine a clean-up remedy for Portland Harbor that was documented in a Record of Decision (ROD) issued on January 6, 2017. The ROD outlines the EPA's selected remediation alternative to clean-up for Portland Harbor which has an estimated total cost of $1.7 billion, comprised of $1.2 billion related to remediation construction costs and $0.5 billion related to long-term operation and maintenance costs, for a combined discounted present value of $1.05 billion. As stated within the ROD, such cost ranges were estimated with accuracy between -30% and +50% of actual costs. Remediation construction costs are estimated to be incurred over a 13 year period, with long-term operation and maintenance costs estimated to be incurred over a 30 year period from the start of construction. The EPA acknowledges the estimated costs are based on data that is now outdated and that a period of pre-remedial design sampling is necessary to gather updated baseline data to better refine the remedial design and estimated cost. The EPA has prepared a Draft Sampling Plan to encourage PRPs to enter into an Administrative Order on Consent with the agency and begin the sampling process before the end of 2017.

PGE is participating in a voluntary process to determine an appropriate allocation of costs amongst the PRPs. Significant uncertainties remain surrounding facts and circumstances that are integral to the determination of such an allocation percentage, including a final allocation methodology and data with regard to property specific activities and history of ownership of sites within Portland Harbor. Based on the above facts and remaining uncertainties, PGE cannot reasonably estimate its potential liability or determine an allocation percentage that represents PGE's portion of the liability to clean-up Portland Harbor.

Where damage to natural resources has occurred as a result of releases of hazardous substances, federal and state natural resource trustees may seek to recover for damages at such sites, which are referred to as natural resource damages. As it relates to the Portland Harbor, PGE has been participating in the Portland Harbor Natural Resource Damages assessment (NRDA) process. The EPA does not manage NRDA activities, but provides claims information and coordination support to the Natural Resource Damages (NRD) trustees. Damage assessment activities are typically conducted by a Trustee Council made up of the trustee entities for the site. The Portland Harbor NRD trustees are the National Oceanic and Atmospheric Administration, the U.S. Fish and Wildlife Service, the State of Oregon, and certain tribal entities.

The NRD trustees may seek to negotiate legal settlements or take other legal actions against the parties responsible for the damages. Funds from such settlements must be used to restore damaged resources and may also compensate the trustees for costs incurred in assessing the damages. The NRD trustees are in the process of negotiating NRDA liability with several PRPs, including PGE. PGE believes that the Company's portion of NRDA liabilities related to Portland Harbor will not have a material impact on its results of operations, financial position, or cash flows.

As discussed above, significant uncertainties still remain concerning the precise boundaries for clean-up, the assignment of responsibility for clean-up costs, the final selection of a proposed remedy by the EPA, results of resampling efforts, and the method of allocation of costs amongst PRPs. It is probable that PGE will share in a portion of these costs. However, the Company does not currently have sufficient information to reasonably estimate the amount, or range, of its potential costs for investigation or remediation of the Portland Harbor site, although such costs could be material. The Company plans to seek recovery of any costs resulting from the Portland Harbor proceeding through claims under insurance policies and regulatory recovery in customer prices.

In July 2016, the Company filed a deferral application with the OPUC seeking the deferral of the future environmental remediation costs, as well as, seeking authorization to establish a regulatory cost recovery mechanism for such environmental costs. The Company reached an agreement with OPUC Staff and other parties regarding the details of the recovery mechanism, which the OPUC approved in the first quarter of 2017. The mechanism will allow the Company to defer and recover incurred environmental expenditures through a combination of third-party proceeds, such as insurance recoveries, and through customer prices, as necessary. The mechanism establishes annual prudency reviews of environmental expenditures and is subject to an annual earnings test.

Trojan Investment Recovery Class Actions

In 1993, PGE closed the Trojan nuclear power plant (Trojan) and sought full recovery of, and a rate of return on, its Trojan costs in a general rate case filing with the OPUC. In 1995, the OPUC issued a general rate order that granted the Company recovery of, and a rate of return on, 87% of its remaining investment in Trojan.

Numerous challenges and appeals were subsequently filed in various state courts on the issue of the OPUC's authority under Oregon law to grant recovery of, and a return on, the Trojan investment. In 2007, following several appeals by various parties, the Oregon Court of Appeals issued an opinion that remanded the matter to the OPUC for reconsideration.

In 2003, in two separate legal proceedings, lawsuits were filed in Marion County Circuit Court (Circuit Court) against PGE on behalf of two classes of electric service customers. The class action lawsuits seek damages totaling $260 million, plus interest, as a result of the Company's inclusion, in prices charged to customers, of a return on its investment in Trojan.

In August 2006, the Oregon Supreme Court (OSC) issued a ruling ordering the abatement of the class action proceedings. The OSC concluded that the OPUC had primary jurisdiction to determine what, if any, remedy could be offered to PGE customers. The OSC also ruled that the plaintiffs retained the right to return to the Circuit Court for disposition of whatever issues remained unresolved from the remanded OPUC proceedings. In October 2006, the Circuit Court abated the class actions in response to the ruling of the OSC.

In 2008, the OPUC issued an order that required PGE to provide refunds of $33 million, including interest, which refunds were completed in 2010. Following appeals, the order was upheld by the Oregon Court of Appeals in February 2013 and by the OSC in October 2014.

In June 2015, at PGE's request, the Circuit Court lifted the abatement and in July 2015, the Circuit Court heard oral argument on the Company's motion for Summary Judgment. In March 2016, the Circuit Court entered a general judgment that granted the Company's motion for Summary Judgment and dismissed all claims by the plaintiffs. On April 14, 2016, the plaintiffs appealed the Circuit Court dismissal to the Court of Appeals for the State of Oregon. Briefing on the appeal is now complete, with a Court of Appeals decision pending.

PGE believes that the October 2014 OSC decision and the recent Circuit Court decisions have reduced the risk of a loss to the Company in excess of the amounts previously recorded and discussed above. However, because the class actions remain subject to a decision in the appeal, management believes that it is reasonably possible that such a loss in excess of amounts previously recorded could result. As these matters involve unsettled legal theories and have a broad range of potential outcomes, sufficient information is currently not available to determine the amount of any such loss.

Deschutes River Alliance Clean Water Act Claims

In August 2016, the Deschutes River Alliance (DRA) filed a lawsuit against the Company in the U.S. District Court of the District of Oregon. DRA's claims seek injunctive and declaratory relief against PGE under the Clean Water Act (CWA) related to alleged past and continuing violations of the CWA. Specifically, DRA claims PGE has violated certain conditions contained in PGE's Water Quality Certification for the Pelton/Round Butte Hydroelectric Project (Project) related to dissolved oxygen, temperature, and measures of acidity or alkalinity of the water. DRA alleges the violations are related to PGE's operation of the Selective Water Withdrawal (SWW) facility at the Project.

The SWW, located above Round Butte Dam, is, among other things, designed to blend water from the surface of the reservoir with water near the bottom of the reservoir and was constructed and placed into service in 2010, as part of the FERC license requirements for the purpose of restoration and enhancement of native salmon and steelhead fisheries above the Project. DRA has alleged that PGE's operation of the SWW has caused the above-referenced violations of the CWA, which in turn have degraded the Deschutes River's fish and wildlife habitat below the Project and harmed the economic and personal interests of DRA's members and supporters.

In September 2016, PGE filed a motion to dismiss, which asserted that the CWA does not allow citizen suits of this nature, and that FERC has jurisdiction over all licensing issues, including the alleged CWA violations. On March 27, 2017, the court denied PGE's motion to dismiss. On April 6, 2017, PGE filed a motion with the District Court for certification to file an interlocutory appeal with the Ninth Circuit and for a stay of the District Court proceeding. On April 7, 2017, the court granted an unopposed motion filed by the Confederated Tribes of Warm Springs (the Tribes) to appear in the case as a friend of the court. The Tribes share ownership of the Project with PGE, but have not been named as a defendant. The District Court granted PGE's request on May 19, 2017, but the Ninth Circuit denied the appeal on August 14, 2017. The parties are engaged in settlement discussions and filed a joint motion, which was granted September 11, 2017, to extend the stay of the District Court proceedings until either party finds the settlement negotiations unproductive.

The Company cannot predict the outcome of this matter, but believes that it has strong defenses to DRA's claims and intends to defend against them. Because i) this matter involves novel issues of law and ii) the mechanism and costs for achieving the relief sought in DRA's claims have not yet been determined, the Company cannot, at this time, determine the likelihood of whether the outcome of this matter will result in a material loss.

Other Matters

PGE is subject to other regulatory, environmental, and legal proceedings, investigations, and claims that arise from time to time in the ordinary course of business that may result in judgments against the Company. Although management currently believes that resolution of such matters, individually and in the aggregate, will not have a material impact on its financial position, results of operations, or cash flows, these matters are subject to inherent uncertainties, and management's view of these matters may change in the future.

NOTE 8: GUARANTEES

PGE enters into financial agreements and power and natural gas purchase and sale agreements that include indemnification provisions relating to certain claims or liabilities that may arise relating to the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnifications cannot be reasonably estimated. PGE periodically evaluates the likelihood of incurring costs under such indemnities based on the Company's historical experience and the evaluation of the specific indemnities. As of September 30, 2017, management believes the likelihood is remote that PGE would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnities. The Company has not recorded any liability on the condensed consolidated balance sheets with respect to these indemnities.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Forward-Looking Statements

The information in this report includes statements that are forward-looking within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements include, but are not limited to, statements that relate to expectations, beliefs, plans, assumptions, and objectives concerning future results of operations, business prospects, future loads, the outcome of litigation and regulatory proceedings, future capital expenditures, market conditions, future events or performance, and other matters. Words or phrases such as "anticipates," "believes," "estimates," "expects," "intends," "plans," "predicts," "projects," "will likely result," "will continue," "should," or similar expressions are intended to identify such forward-looking statements.

Forward-looking statements are not guarantees of future performance and involve risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed. PGE's forward-looking statements are expressed in good faith and are believed to have a reasonable basis including, but not limited to, management's examination of historical operating trends and data contained either in internal records or available from third parties, but there can be no assurance that the expectations, beliefs, or projections contained in such forward-looking statements will be achieved or accomplished.

In addition to any assumptions and other factors and matters referred to specifically in connection with such forward-looking statements, factors that could cause actual results or outcomes for PGE to differ materially from those discussed in forward-looking statements include:

- governmental policies and regulatory audits, investigations and actions, including those of the FERC and the OPUC with respect to allowed rates of return, financings, electricity pricing and price structures, acquisition and disposal of facilities and other assets, construction and operation of plant facilities, transmission of electricity, recovery of power costs and capital investments, and current or prospective wholesale and retail competition;
- economic conditions that result in decreased demand for electricity, reduced revenue from sales of excess energy during periods of low wholesale market prices, impaired financial stability of vendors and service providers, and elevated levels of uncollectible customer accounts;
- the outcome of legal and regulatory proceedings and issues including, but not limited to, the matters described in Note 7, Contingencies, in the Notes to the Condensed Consolidated Financial Statements;
- unseasonable or extreme weather and other natural phenomena, which could affect customers' demand for power and PGE's ability and cost to procure adequate power and fuel supplies to serve its customers, and could increase the Company's costs to maintain its generating facilities and transmission and distribution systems;
- operational factors that could affect PGE's power generating facilities, including forced outages, adverse hydro and wind conditions, and fuel supply disruptions, any of which may cause the Company to incur repair costs or purchase replacement power at increased costs;
- the failure to complete capital projects on schedule and within budget or the abandonment of capital projects, either of which could result in the Company's inability to recover project costs;
- volatility in wholesale power and natural gas prices, which could require PGE to issue additional letters of credit or post additional cash as collateral with counterparties pursuant to power and natural gas purchase agreements;
- changes in the availability and price of wholesale power and fuels, including natural gas and coal, and the impact of such changes on the Company's power costs;
- capital market conditions, including availability of capital, volatility of interest rates, reductions in demand for investment-grade commercial paper, as well as changes in PGE's credit ratings, any of which could have an impact on the Company's cost of capital and its ability to access the capital markets to support requirements for working capital, construction of capital projects, and the repayments of maturing debt;
- future laws, regulations, and proceedings that could increase the Company's costs of operating its thermal generating plants, or affect the operations of such plants by imposing requirements for additional emissions controls or significant emissions fees or taxes, particularly with respect to coal-fired generating facilities, in order to mitigate carbon dioxide, mercury, and other gas emissions;
- changes in, and compliance with, environmental laws and policies, including those related to threatened and endangered species, fish, and wildlife;
- the effects of climate change, including changes in the environment that may affect energy costs or consumption, increase the Company's costs, or adversely affect its operations;
- changes in residential, commercial, and industrial customer growth, and in demographic patterns, in PGE's service territory;
- the effectiveness of PGE's risk management policies and procedures;

- declines in the fair value of securities held for the defined benefit pension plans and other benefit plans, which could result in increased funding requirements for such plans;
- cyber security attacks, data security breaches, or other malicious acts that cause damage to the Company's generation and transmission facilities or information technology systems, or result in the release of confidential customer, employee, or Company information;
- employee workforce factors, including potential strikes, work stoppages, transitions in senior management, and employee retirements;
- new federal, state, and local laws that could have adverse effects on operating results;
- natural disasters and other risks such as earthquake, flood, drought, lightning, wind, and fire;
- changes in financial or regulatory accounting principles or policies imposed by governing bodies; and
- acts of war or terrorism.

Any forward-looking statement speaks only as of the date on which such statement is made and, except as required by law, PGE undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for management to predict all such factors or assess the impact of any such factor on the business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement.

Overview

Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) is intended to provide an understanding of the business environment, results of operations, and financial condition of PGE. This MD&A should be read in conjunction with the Company's condensed consolidated financial statements contained in this report, as well as the consolidated financial statements and disclosures in its Annual Report on Form 10-K for the year ended December 31, 2016, and other periodic and current reports filed with the SEC.

PGE is a vertically integrated electric utility engaged in the generation, transmission, distribution, and retail sale of electricity, as well as the wholesale purchase and sale of electricity and natural gas in order to meet the needs of its retail customers. The Company generates revenues and cash flows primarily from the sale and distribution of electricity to retail customers in its service territory.

In the fourth quarter of 2016, PGE submitted to the OPUC its 2016 Integrated Resource Plan (IRP), which addresses the Company's proposal to meet future customer demand and describes PGE's future energy supply strategy and anticipated resource needs over the next 20 years. The areas of focus for the plan, include, among other topics, additional resources needed to meet Oregon's Renewable Portfolio Standard (RPS) requirements and to replace energy from Boardman, the Company's coal-fired generating plant located in Eastern Oregon that will cease coal-fired operations at the end of 2020. For further information regarding the IRP, see *"Integrated Resource Plan"* in this Overview section of Item 2.

In February 2017, PGE filed a general rate case for a 2018 test year. Stipulations filed on September 18, 2017 and October 9, 2017 reflect settlement of all issues. The Company expects the OPUC to authorize new customer prices effective January 1, 2018. For further information, see *"General Rate Case"* in this Overview section of Item 2.

On October 1, 2017, the Company began active participation in the Western Energy Imbalance Market (EIM). As a market participant, PGE's generating plants now receive automated dispatch signals from the California Independent System Operator that allows for load balancing with other EIM participants in five-minute intervals, which the Company expects will help integrate more renewable energy into the grid by better matching the variable output of renewable resources. Additionally, this gives PGE access to the least-cost energy available in the region to meet changes in real-time energy demand and short-term variations in customer demand.

The discussion that follows in this MD&A provides additional information related to the Company's operating activities, legal, regulatory, and environmental matters, results of operations, and liquidity and financing activities.

Capital Requirements and Financing—The Company expects 2017 capital expenditures to total $533 million, excluding AFDC. For additional information regarding estimated capital expenditures, see "*Capital Requirements*" in the Liquidity and Capital Resources section of this Item 2.

PGE plans to fund capital requirements and maturities of long-term debt during the year of $150 million with cash from operations during 2017, which is expected to range from $515 million to $565 million, and the issuance of debt securities of $225 million. For additional information, see *"Liquidity"* and *"Debt and Equity Financings"* in the Liquidity and Capital Resources section of this Item 2.

General Rate Case—On February 28, 2017, the Company filed with the OPUC a general rate case based on a 2018 test year (2018 GRC). The filing includes investments to ensure system safety and reliability and to better meet customers' changing needs and service expectations. PGE's initial filing proposed a $100 million increase in the annual revenue requirement related primarily to an increase in base business costs for upgrades to PGE's transmission and distribution system, investments in strengthening and safeguarding the grid, and support for key initiatives such as participation in the Western Energy Imbalance Market (EIM). The proposal was based upon:

- A capital structure of 50% debt and 50% equity;
- A return on equity of 9.75%; and
- A rate base of $4.6 billion.

PGE, OPUC staff, and certain customer groups have reached agreements that resolve all issues in the case, provide for an expected $20 million net increase in annual revenue requirements, and reflect:

- A capital structure of 50% debt and 50% equity;
- A return on equity of 9.5%; and
- A rate base of $4.5 billion.

The net increase in annual revenue requirement as proposed in the Company's initial filing and as revised consists of the following (in millions):

As Filed February 28, 2017		$ 100
Load and Power Cost Updates		(28)
Depreciation Study Updates		(8)
Base Business Revenue Requirement Updates:		
Lower return on equity	$ (10)	
Lower labor costs	(9)	
Adjustment to depreciation expense	(8)	
Lower level of plant in service	(5)	
Other reductions to rate base	(4)	
Other various modifications	(8)	
Subtotal		(44)
As Stipulated		$ 20

Regulatory review of the 2018 GRC will continue until the final order is issued, which is expected in December 2017, with new customer prices expected to become effective January 1, 2018. Final revenue requirement amounts subject to revision include power costs (to be finalized November 2017) and actual cost of debt, including any additional debt issuances. Any subsequent reductions in PGE's overall cost of long-term debt through June 30, 2018 will be reflected either in the final 2018 GRC update or through a supplemental tariff filing. All stipulations remain subject to OPUC approval.

The 2018 GRC filing (OPUC Docket UE 319), as well as copies of direct and reply testimony, exhibits, and stipulations are available on the OPUC website at www.oregon.gov/puc.

Operating Activities—The impact of seasonal weather conditions on demand for electricity can cause the Company's revenues and income from operations to fluctuate from period to period. PGE typically experiences its highest average MWh deliveries and retail energy sales during the winter heating season, although deliveries also increase during the summer months, generally resulting from air conditioning demand. Retail customer price changes and customer usage patterns, which can be affected by the economy, also have an effect on revenues while wholesale power availability and price, hydro and wind generation, and fuel costs for thermal and gas plants can also affect income from operations.

Customers and Demand—The 5.9% increase in retail energy deliveries for the nine months ended September 30, 2017 compared with the nine months ended September 30, 2016 resulted from increases in all retail categories with the greatest percentage increase in residential deliveries, which are most sensitive to fluctuations in weather.

Energy deliveries to residential customers increased 10.4% due in large part to the effects of cooler temperatures during the heating season and warmer temperatures during the cooling season, as well as customer growth of 1.3%. Energy deliveries to industrial customers increased 5.1%, largely due to continued strength in the high tech sector. Weather adjusted deliveries increased 0.3% from the first nine months of 2016 reflecting strength in the industrial sector. One additional day in 2016 due to leap year resulted in a comparative decrease of 0.4% in retail energy deliveries. Energy efficiency and conservation efforts by retail customers also influence demand, although the financial effects of such efforts by residential and certain commercial customers are mitigated by the decoupling mechanism. See *"Legal, Regulatory and Environmental"* in this Overview section of Item 2 for further information on the decoupling mechanism.

During the third quarter of 2017, cooling degree-days, an indication of the extent to which customers are likely to have used electricity for cooling, were 45% above the third quarter of 2016. Residential energy deliveries, which are most weather sensitive, were 12.3% higher in the third quarter of 2017 than the third quarter of 2016. Unseasonably warm weather in first quarter of 2016, which decreased energy deliveries in that quarter, and temperatures that resulted in more heating and cooling degree days in the second quarter of 2017 also contributed to the increased deliveries on a year-to-date basis. See *"Revenues"* in the Results of Operations section of this Item 2 for further information on heating degree days.

The following table, which also includes deliveries to the Company's direct access customers who purchase their energy from Electricity Service Suppliers, presents the average number of retail customers by customer type, and the corresponding energy deliveries, for the periods indicated:

	Nine Months Ended September 30,				
	2017		2016		
	Average Number of Customers	Retail Energy Deliveries*	Average Number of Customers	Retail Energy Deliveries*	% Increase (Decrease) in Energy Deliveries
Residential	761,028	5,826	751,198	5,278	10.4%
Commercial (PGE sales only)	107,296	5,193	106,458	5,148	0.9%
Direct Access	479	472	314	403	17.1%
Total Commercial	107,775	5,665	106,772	5,551	2.1%
Industrial (PGE sales only)	198	2,187	193	2,168	0.9%
Direct Access	68	1,046	63	907	15.3%
Total Industrial	266	3,233	256	3,075	5.1%
Total (PGE sales only)	868,522	13,206	857,849	12,594	4.9%
Total Direct Access	547	1,518	377	1,310	15.9%
Total	869,069	14,724	858,226	13,904	5.9%

* In thousands of MWh.

The Company's Retail Customer Choice Program caps participation by Direct Access customers in the fixed three-year and minimum five-year opt-out programs, which account for the majority of energy supplied to Direct Access customers. This cap would have limited energy deliveries to these customers to an amount equal to approximately 13% of PGE's total retail energy deliveries for the first nine months of 2017. Energy deliveries to Direct Access customers represented 9% of the Company's total retail energy deliveries for the full year 2016, compared with 10% in the first nine months of 2017.

Power Operations—To meet the energy needs of its retail customers, the Company utilizes a combination of its own generating resources and power purchases in the wholesale market. In an effort to obtain reasonably-priced power for its retail customers, PGE makes economic dispatch decisions based on numerous factors including plant availability, customer demand, river flows, wind conditions, and current wholesale prices.

PGE's generating plants require varying levels of annual maintenance, during which the respective plants are unavailable to provide power. As a result, the amount of power generated to meet the Company's retail load requirement can vary from period to period. Plant availability, which is affected by both planned and unplanned outages, approximated 90% and 94% during the nine months ended September 30, 2017 and 2016, respectively, for those plants PGE operates. Plant availability of Colstrip Units 3 and 4, of which the Company has a 20% ownership interest, approximated 85% during the nine months ended September 30, 2017 and 2016, respectively.

During the nine months ended September 30, 2017, the Company's generating plants provided 65% of its retail load requirement compared with 69% in the nine months ended September 30, 2016. The decrease in the proportion of power generated to meet the Company's retail load requirement was largely due to the combination of decreased production from the Company's wind facilities due to unfavorable weather conditions and a reduction in energy provided from the Company's thermal generation facilities due to outages and economic displacement. The decrease was partially offset by favorable hydro generation, during the first nine months of 2017. Favorable hydro conditions within the region had the effect of reducing energy prices in the wholesale power market which allowed the Company to economically displace a greater portion of its thermal generation to meet its retail load requirement.

Energy expected to be received from PGE-owned hydroelectric plants and under contracts from mid-Columbia hydroelectric projects is projected annually in the Annual Power Cost Update Tariff (AUT). Any excess in such hydro generation from that projected in the AUT normally displaces power from higher cost sources, while any shortfall is normally replaced with power from higher cost sources. For the nine months ended September 30, 2017, energy received from these hydro resources increased by 13% compared to the nine months ended September 30, 2016. Energy received from these hydro resources exceeded projected levels included in PGE's AUT by 10% and fell below projected levels by 2% for the nine months ended September 30, 2017 and 2016, respectively, and provided 19% and 18% of the Company's retail load requirement for the nine months ended September 30, 2017 and 2016, respectively. Energy from hydro resources is expected to exceed levels projected in the AUT for 2017.

Energy expected to be received from PGE-owned wind generating resources (Biglow Canyon and Tucannon River) is projected annually in the AUT. Any excess in wind generation from that projected in the AUT normally displaces power from higher cost sources, while any shortfall is normally replaced with power from higher cost sources. For the nine months ended September 30, 2017, energy received from these wind generating resources decreased 18% compared to the nine months ended September 30, 2016, resulting in the Company incurring higher replacement costs, as well as generating fewer Production Tax Credits (PTCs) than what was estimated in customer prices. Energy received from these wind generating resources fell short of that projected in PGE's AUT by 20% for the nine months ended September 30, 2017 and 6% for the nine months ended September 30, 2016, and provided 9% and 12% of the Company's retail load requirement during the nine months ended September 30, 2017 and 2016, respectively. Energy from wind resources is expected to be below projected levels included in the AUT for 2017.

Pursuant to the Company's power cost adjustment mechanism (PCAM), customer prices can be adjusted to reflect a portion of the difference between each year's forecasted net variable power costs (NVPC) included in customer prices (baseline NVPC) and actual NVPC for the year. NVPC consists of the cost of power purchased and fuel used to generate electricity to meet PGE's retail load requirements, as well as the cost of settled electric and natural gas financial contracts (all classified as Purchased power and fuel expense in the Company's condensed consolidated statements of income) and is net of wholesale revenues, which are classified as Revenues, net in the condensed consolidated statements of income. Effective January 1, 2017, PGE's 2017 AUT filing included projected PTCs for the 2017 calendar year with actual variances subject to the PCAM. To the extent actual annual NVPC, subject to certain adjustments, is above or below the deadband, which is a defined range from $30 million above to $15 million below baseline NVPC, the PCAM provides for 90% of the variance beyond the deadband to be collected from, or refunded to, customers, respectively, subject to a regulated earnings test.

Any estimated refund to customers pursuant to the PCAM is recorded as a reduction in Revenues, net in the Company's condensed consolidated statements of income, while any estimated collection from customers is recorded as a reduction in Purchased power and fuel expense.

For the nine months ended September 30, 2017, actual NVPC was $14 million above baseline NVPC. Based on forecast data, NVPC for the year ending December 31, 2017 is currently estimated to be above the baseline NVPC, but within the deadband range. Accordingly, no estimated collection from, or refund to, customers is expected under the PCAM for 2017.

For the nine months ended September 30, 2016, actual NVPC was $3 million below baseline NVPC. For the year ended December 31, 2016, actual NVPC was $10 million below baseline NVPC, which was within the established deadband range. Accordingly, no estimated refund to customers was recorded pursuant to PCAM for 2016.

PGE has contractual access to natural gas storage in Mist, Oregon from which it can draw in the event that natural gas supplies are interrupted or if economic factors require its use. The storage facility is owned and operated by a local natural gas company, NW Natural, and may be utilized to provide fuel to PGE's Port Westward Unit 1 and Beaver natural gas-fired generating plants and the Port Westward Unit 2 natural gas-fired flexible capacity generating plant. PGE has entered into a long-term agreement with this gas company to expand the current storage facilities, including the construction of a new reservoir, compressor station, and 13-miles of pipeline, which will collectively be designed to provide no-notice storage services to these PGE generating plants. NW Natural estimates construction will be completed during the winter of 2018-2019, at a cost of approximately $128 million. Due to the level of PGE's involvement during the construction period, the Company is deemed to be the owner of the assets for accounting purposes during the construction period. As a result, PGE has recorded $94 million to construction work-in-progress (CWIP) and a corresponding liability for the same amount to Other noncurrent liabilities in the condensed consolidated balance sheets as of September 30, 2017. Upon completion of the facility, PGE will assess whether the assets and liabilities qualify as a successful sale-leaseback transaction in which the asset and liability are removed and accounted for as either a capital or operating lease.

Carty—Pursuant to the final order issued by the OPUC on November 3, 2015 in connection with the Company's 2016 GRC, the Company was authorized to include in customer prices the capital costs for Carty of up to $514 million, as well as Carty's operating costs, effective August 1, 2016, following the placement of the plant into service on July 29, 2016. As the final construction cost exceeded the amount authorized by the OPUC, higher interest and depreciation expense than allowed in the Company's revenue requirement has resulted. This higher cost of service is primarily due to depreciation and amortization on the incremental capital cost, interest expense, and legal expense, all of which totaled $12 million for the nine months ended September 30, 2017 and is estimated to be approximately $14 million for the full year 2017.

On July 29, 2016, the Company requested from the OPUC a regulatory deferral for the recovery of the revenue requirement associated with the incremental capital costs for Carty starting from its in service date to the date that such amounts are approved in a subsequent GRC proceeding. The Company has requested the OPUC delay its review of this deferral request until the Company's claims against the Sureties have been resolved. Until such time, the effects of this higher cost of service will be recognized in the Company's results of operations. Any amounts approved by the OPUC for recovery under the deferral filing will be recognized in earnings in the period of such approval.

For additional details regarding various legal and regulatory proceedings related to Carty, see Note 7, Contingencies, in the Notes to the Condensed Consolidated Financial Statements.

Legal, Regulatory, and Environmental Matters—PGE is a party to certain proceedings, the ultimate outcome of which may have a material impact on the results of operations and cash flows in future reporting periods. Such proceedings include, but are not limited to, the following matters:

- An investigation of environmental matters regarding Portland Harbor;
- Claims pertaining to the termination of the Construction Agreement for Carty and recovery of incremental costs.

For additional information regarding the above and other matters, see Note 7, Contingencies, in the Notes to Condensed Consolidated Financial Statements.

Oregon Clean Electricity and Coal Transition Plan—The State of Oregon passed Senate Bill 1547, effective in March 2016, a law referred to as the Oregon Clean Electricity and Coal Transition Plan (OCEP). The legislation has impacted PGE in several ways, including preventing the Company from including the costs and benefits associated with coal-fired generation in Oregon retail rates after 2030 (subject to an exception that extends this date until 2035 for the Company's output from the Colstrip facility). As a result, in October 2016, the Company filed a tariff request, and the OPUC approved the request, to incorporate in customer prices, on January 1, 2017, the approximate

$6 million annual effect of accelerating recovery of the Colstrip facility from 2042 to 2030, as required under the legislation.

Future effects under the new law include:

- an increase in RPS thresholds to 27% by 2025, 35% by 2030, 45% by 2035, and 50% by 2040;
- a limitation on the life of renewable energy certificates (RECs) generated from facilities that become operational after 2022 to five years, but continued unlimited lifespan for all existing RECs and allowance for the generation of additional unlimited RECs for a period of five years for projects on line before December 31, 2022; and
- an allowance for energy storage costs in its renewable adjustment clause mechanism (RAC) filings.

The Company has evaluated the potential impacts and has incorporated the effects of the legislation into its 2016 IRP.

Clean Power Plan—In August 2015, the U.S. Environmental Protection Agency (EPA) released a final rule, which it calls the "Clean Power Plan" (CPP). Under the final rule, each state would have to reduce the carbon intensity of its power sector on a state-wide basis by an amount specified by the EPA. The rule establishes state-specific goals in terms of pounds of carbon dioxide emitted per MWh of energy produced. The rule is intended to result in a reduction of carbon emissions from existing power plants across all states to approximately 32% below 2005 levels by 2030.

The target amount was determined based on the EPA's view of the options for each state, including: i) making efficiency upgrades at fossil fuel-fired power plants; ii) shifting generation from coal-fired plants to natural gas-fired plants; and iii) expanding use of zero- and low-carbon emitting generation (such as renewable energy and nuclear energy). The final goal would need to be met by 2030 and interim goals for each state would need to be met from 2022 to 2029. Under the rule, states have flexibility in designing programs to meet their emission reduction targets, including the three approaches noted above and any other measures the states choose to adopt (such as carbon tax and cap-and-trade) that would result in verified emission reductions.

PGE cannot predict how the states in which the Company's thermal generation facilities are located (Oregon and Montana) will implement the rule or how the rule may impact the Company's operations. The Company continues to monitor the developments around the implementation of the rule and efforts by state regulators to develop state plans. On February 9, 2016, the United States Supreme Court granted a stay, halting implementation and enforcement of the CPP pending the resolution of legal challenges to the rule.

On March 28, 2017, the President of the United States issued an Executive Order that directed various agencies to review existing regulations that "potentially burden" the development of the nation's energy resources. Among other items, the Executive Order specifically directs the EPA to take several actions relating to the CPP. The EPA is instructed to review the final CPP and the final new source performance standard rules for new and modified power plants (NSPS) under the Clean Air Act and suspend, revise, or rescind the rules, if appropriate. On October 16, 2017, the EPA published a proposed rule that is now open for comment, in which it outlined the rationale for repealing the CPP.

The Company cannot predict the impact of the stay, the ultimate outcome of the legal challenges, or whether Oregon and Montana will continue to develop implementation plans in light of the Supreme Court stay, the Executive Order, and consequential EPA actions.

SB 978—The State of Oregon legislature passed a bill in its 2017 session referred to as SB 978, which directs the OPUC to investigate and provide a report to the legislature by September 15, 2018 on how developing industry trends, technology, and policy drivers in the electricity sector might impact the existing regulatory system and incentives. PGE is actively working on this initiative, both internally and in conjunction with the OPUC, to provide guidance and support development of the report.

Recovery of Utility License Fees—In May 2011, the city of Gresham, Oregon (Gresham), which is within PGE's service territory, adopted a resolution to increase utility license fees from 5% to 7%, effective July 1, 2011. The Company believed that these utility license fees met the definition of privilege taxes within the Oregon statutes and that Gresham's increase violated the statutory 5% limitation on such taxes. PGE began collecting the incremental 2% tax from customers in Gresham, but filed suit against Gresham in Multnomah County Circuit Court, claiming that such an increase in privilege taxes violated Oregon law. In January, 2012, the Multnomah County Circuit Court ruled in favor of PGE, and the Company ceased collecting from Gresham customers the incremental 2% tax. Gresham appealed the Multnomah County Circuit Court decision to the Oregon Court of Appeals, which subsequently ruled in Gresham's favor.

PGE appealed the Court of Appeals' ruling to the Oregon Supreme Court and on August 4, 2016, the Oregon Supreme Court issued its appellate judgment in favor of Gresham. As a result of this ruling, the Company was required to pay Gresham $0.8 million, which represented the amount it had already collected from customers, plus $7 million for the remaining accrued, but uncollected, amount of incremental taxes that were not paid to Gresham when due, covering the period from July 1, 2011 through September 1, 2016. PGE recorded a corresponding regulatory asset for the $7 million. On February 24, 2017, the Company made a filing requesting that the OPUC allow recovery of the $7 million from customers in Gresham over a five-year period.

On May 26, 2017, the OPUC Staff recommended against such recovery, stating that the OPUC has no legal authority to allow PGE to retroactively recover, from customers in Gresham, costs arising from the City's privilege tax increase. PGE disputes the Staff's position and believes that such amounts are legally eligible for recovery through customer prices. However, the Company cannot predict the outcome of this matter. The OPUC has indicated that it will render a decision by February 1, 2018.

Other Regulatory Matters—The following discussion highlights certain regulatory items that have impacted the Company's revenues, results of operations, or cash flows for the first three quarters of 2017 compared to the first three quarters of 2016, or have affected retail customer prices, as authorized by the OPUC. In some cases, the Company has deferred the related expenses or benefits as regulatory assets or liabilities, respectively, for later amortization and inclusion in customer prices, pending OPUC review and authorization.

Power Costs—Pursuant to the AUT process, PGE files annually an estimate of power costs for the following year. Effective January 1, 2017, customer prices were decreased $56 million annually from 2016 levels to reflect an expected reduction in power costs under the AUT. As part of its 2018 GRC, PGE included a projected reduction in power costs of $29 million that was included in the overall request submitted to the OPUC and expected to be reflected in customer prices effective January 1, 2018. As submitted in the September 29, 2017 GRC update, PGE further reduced the projected power costs that resulted in a total reduction of $36 million. Pursuant to the schedule established in the proceeding, updates of the forecast will occur through mid-November that could change this estimate.

Under the PCAM for 2016, NVPC was within the limits of the deadband, thus no potential refund or collection was recorded. The OPUC will review the results of the PCAM for 2016 during the latter half of 2017 with a decision expected in the fourth quarter 2017.

As a result of the recently passed OCEP legislation described above, PGE's 2017 AUT filing included projected PTCs for the 2017 calendar year. Prior to this legislative change, PGE included forecasts of PTCs only in General Rate Case proceedings. The inclusion of PTCs in the AUT provides for annual forecast updates for these estimated tax credits, thus reducing the risk of regulatory lag in terms of adjusting customer prices, as well as providing the Company an opportunity to potentially collect or refund variances from projected PTC's pursuant to the PCAM.

Renewable Resource Costs—Pursuant to the RAC, PGE can recover in customer prices prudently incurred costs of renewable resources that are expected to be placed in service in the current year. The Company may submit a filing to the OPUC by April 1st each year, with prices expected to become effective January 1st of the following year. As part of the RAC, the OPUC has authorized the deferral of eligible costs not yet included in customer prices until the January 1st effective date.

In March 2016, PGE submitted to the OPUC a RAC filing that requested no significant additions or deferrals for 2016. No RAC filing has been submitted in 2017.

Decoupling—The decoupling mechanism, which the OPUC has authorized through 2019, provides for recovery of margin lost as a result of a reduction in electricity sales attributable to energy efficiency, customer-owned generation, and conservation efforts by residential and certain commercial customers. The mechanism provides for collection from (or refund to) customers if weather adjusted use per customer is less (or more) than that projected in the Company's most recent general rate case.

Accordingly, a refund of the $5 million recorded during 2014 occurred over a one-year period, which began January 1, 2016. The $9 million refund recorded in 2015 that resulted from variances between actual weather adjusted use per customer and that projected in the 2015 GRC, is expected to occur over a one-year period, which began January 1, 2017. The Company recorded an estimated collection of $3 million during the year ended December 31, 2016, as a result of variances from amounts established in the 2016 GRC. Any collection for the year ended December 31, 2016 is expected to occur over a one-year period, which would begin January 1, 2018.

The Company recorded an estimated collection of $9 million during the nine months ended September 30, 2017, which resulted from projections established in the 2016 GRC. Collections under the decoupling mechanism are subject to an annual limitation, which for 2017 would currently stand at $18 million. Any collection from (or refund to) customers for the 2017 year is expected to occur over a one-year period, which would begin January 1, 2019.

Storm Restoration Costs—Beginning in 2011, the OPUC authorized the Company to collect $2.0 million annually from retail customers to cover incremental expenses related to major storm damages, and to defer any amount not utilized in the current year. If approved, stipulations filed with the OPUC in the 2018 GRC would increase the annual collection amount to $2.6 million, annually beginning in 2018.

During 2015 and 2016, PGE fully utilized the existing reserve balance as a result of restoration costs associated with storm damage occurring during those years. As a result of a series of storm events in the first half of 2017, the Company exhausted the $2 million storm collection authorized for 2017. Consequently, PGE is exposed to the incremental costs to-date related to such major storms events, which total $10 million, less the amount to be collected in 2017, as well as any additional major storm damage costs experienced during the remainder of 2017.

As a result of the additional costs incurred, during the first quarter of 2017, PGE filed an application with the OPUC requesting authorization to defer incremental storm restoration costs from the date of the application through the end of 2017, net of the $2 million being collected annually under the existing methodology. Since the application will not likely be reviewed until 2017 is complete, and all applicable costs are identified, the Company is unable to predict how the OPUC will ultimately rule on this application. The Company is unable to state with any certainty at this time whether these incremental costs are probable of recovery and, accordingly, no deferral has been recorded to-date. In the event it becomes probable that some or all of these costs are recoverable, the Company will record a deferral for such amounts at such time.

Integrated Resource Plan—In November 2016, PGE filed an IRP (2016 IRP) with the OPUC. The 2016 IRP addresses acquisition of additional resources to meet RPS requirements and replace energy and capacity from Boardman, which will cease coal-fired operations at the end of 2020. Further actions identified through 2021 are expected to offset expiring power purchase agreements and integrate variable energy resources, such as wind or solar generation facilities. The 2016 IRP also considers the OCEP, which, among other things, increased the RPS requirements for 2025 and future years. For further information on the OCEP, see the *"Legal, Regulatory and Environmental"* section in this Overview section of Item 2.

All portfolios analyzed in the 2016 IRP pursue:

- compliance with the RPS through 2050;
- inclusion of cost-effective customer-side options, including energy efficiency, demand response, conservation voltage reduction, and dispatchable standby generation; and
- retention of all existing power plants until 2050, with the exception of Boardman and Colstrip Units 3 & 4.

In August 2017, the OPUC acknowledged PGE's 2016 IRP and the following primary action plan items:

- Acknowledge capacity needs of 561 MW, of which 240 MW must be dispatchable, in 2021;
- Acquire a total of 135 MWa of cost-effective energy efficiency;
- Acquire at least 77 MW (winter) and 69 MW (summer) demand response through 2020 and 16 MW of dispatchable standby generation from customers to help manage peak load conditions and other supply contingencies;
- Deploy 1 MWa of conservation voltage reduction through 2020;
- Submit one or more energy storage proposals in accordance with House Bill 2193, by January 1, 2018, with an initial proposal expected to be filed with the OPUC by mid-November 2017; and
- Perform various research and studies related to flexible capacity and curtailment metrics, customer insights, decarbonization, risks associated with Direct Access, treatment of market capacity, accessing resources from Montana, and load forecasting improvements.

PGE is engaged in bilateral negotiations with owners of existing regional resources to fill its capacity need. In August 2017, the Company filed with the OPUC a request for a waiver of the OPUC's competitive bidding guidelines. In that filing, PGE requests a waiver to procure 350 - 450 MW of capacity to partially satisfy PGE's 561 MW capacity deficit. PGE expects additional capacity contributions from contracts with Qualifying Facilities as defined by the Public Utility Regulatory Policies Act of 1978, acquisition of energy storage in compliance with House Bill 2193, and an assumed capacity contribution from incremental renewables procured through a request for proposal (RFP). The OPUC is scheduled to make a decision on the waiver request by December 5, 2017 and the Company currently anticipates negotiations to be complete by the end of the first quarter of 2018. Following the outcome of the bilateral negotiations and waiver process, PGE may request approval from the OPUC to issue RFPs for any remaining capacity need.

The OPUC did not acknowledge PGE's proposed actions for acquiring renewable resources and asked the Company to work with OPUC staff and parties to prepare and submit a revised proposal, which PGE presented at a public meeting on October 10, 2017. In the revised proposal, the Company identified the potential of revising the procurement target for the addition of RPS compliant renewable resources to 100 MWa, which could include unbundled RECs. PGE expects to submit an IRP addendum by the end of 2017 that would seek acknowledgement of a revised renewable action plan, including the issuance of RFPs for renewable resources.

Since issuing the IRP, PGE has identified a potential benchmark wind resource that could have a nameplate capacity of up to approximately 300 MW, that would meet the need for the renewable resources, and which would qualify for the production tax credit. The Company continues to explore this option. The submission of this resource into an

RFP for renewable resources as a benchmark bid is subject to additional due diligence and negotiation along with execution of definitive agreements. If agreements are reached, the potential benchmark resource would be considered in the RFP along with other renewable resource offerings.

The RFP process will include oversight by an independent evaluator and review by the OPUC.

Critical Accounting Policies

PGE's critical accounting policies are outlined in Item 7 of the Company's Annual Report on Form 10-K for the year ended December 31, 2016, filed with the SEC on February 17, 2017.

Results of Operations

The following table contains condensed consolidated statements of income information for the periods presented (dollars in millions):

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2017		2016		2017		2016	
Revenues, net	$ 515	100%	$ 484	100%	$ 1,494	100%	$ 1,399	100%
Purchased power and fuel	184	36	180	37	443	30	455	33
Gross margin	331	64	304	63	1,051	70	944	67
Other operating expenses:								
Generation, transmission and distribution	73	14	69	14	235	16	199	14
Administrative and other	64	12	63	13	197	13	185	13
Depreciation and amortization	87	17	79	17	257	17	244	18
Taxes other than income taxes	30	6	29	6	94	6	89	6
Total other operating expenses	254	49	240	50	783	52	717	51
Income from operations	77	15	64	13	268	18	227	16
Interest expense*	30	6	28	6	90	6	82	6
Other income:								
Allowance for equity funds used during construction	4	1	4	1	9	1	19	1
Miscellaneous income, net	2	1	—	—	4	—	—	—
Other income, net	6	2	4	1	13	1	19	1
Income before income tax expense	53	11	40	8	191	13	164	11
Income tax expense	13	3	6	1	46	3	32	2
Net income	$ 40	8%	$ 34	7%	$ 145	10%	$ 132	9%

* Net of an allowance for borrowed funds used during construction of $1 million for the three months ended September 30, 2017 and 2016, and $4 million and $10 million for the nine months ended September 30, 2017 and 2016.

Net income was $40 million, or $0.44 per diluted share, for the three months ended September 30, 2017 compared with $34 million, or $0.38 per diluted share, for the three months ended September 30, 2016. The increase in Net income reflects higher usage per customer across all customer classes, along with the effect of warmer weather in 2017 compared to the same period of 2016. Depreciation and amortization expense increased due to capital additions including Carty, a portion of which is offset in higher revenues.

Net income was $145 million, or $1.62 per diluted share, for the nine months ended September 30, 2017, compared with $132 million, or $1.49 per diluted share, for the nine months ended September 30, 2016. Temperature contrasts contributed to higher energy demand in the first three quarters of 2017 than 2016 and helped improve Gross margin. While total deliveries and customer growth remains favorable, weather-adjusted usage per residential customer continues a pattern of long-term decline. As a result, the Company recorded a $6 million increase in the estimated collection under the Decoupling mechanism in the first three quarters of 2017 compared with the first three quarters of 2016. Net income was aided by reduced NVPC as the average variable power cost per MWh declined 5%. NVPC was $14 million above baseline NVPC for the first three quarters of 2017, compared with $3 million below the baseline for the first three quarters of 2016. Allowance for equity funds used during construction decreased by $10 million in the first three quarters of 2017 in comparison with the first three quarters of 2016 due to lower average CWIP balances. Higher operating expenses, including additional depreciation expense, contributed to partially offset the higher net income. Lower AFDC in 2017 resulted from the completion of Carty in July 2016, and, although recovery in customer prices began in August 2016, some earnings drag continues as costs exceeded those authorized by the OPUC. Expenses related to Carty (primarily incremental depreciation, interest, and legal costs) continue to reduce earnings.

Three Months Ended September 30, 2017 Compared with the Three Months Ended September 30, 2016

Revenues, energy deliveries (presented in MWh), and the average number of retail customers consist of the following for the periods presented:

	Three Months Ended September 30,			
	2017		2016	
Revenues* (dollars in millions):				
Retail:				
Residential	$ 224	43 %	$ 203	42%
Commercial	178	35	170	35
Industrial	55	11	54	11
Subtotal	457	89	427	88
Other retail revenues, net	(2)	(1)	1	—
Total retail revenues	455	88	428	88
Wholesale revenues	50	10	48	10
Other operating revenues	10	2	8	2
Total revenues	$ 515	100 %	$ 484	100%
Energy deliveries (MWh in thousands):				
Retail:				
Residential	1,817	29 %	1,618	27%
Commercial	1,851	30	1,751	30
Industrial	752	12	754	13
Subtotal	4,420	71	4,123	70
Direct access:				
Commercial	169	3	141	2
Industrial	366	6	301	5
Subtotal	535	9	442	7
Total retail energy deliveries	4,955	80	4,565	77
Wholesale energy deliveries	1,224	20	1,360	23
Total energy deliveries	6,179	100 %	5,925	100%
Average number of retail customers:				
Residential	763,553	88 %	753,345	87%
Commercial	108,705	12	107,844	13
Industrial	200	—	204	—
Direct access	588	—	373	—
Total	873,046	100 %	861,766	100%

* Includes revenues from customers who purchase their energy from the Company as well as $10 million and $7 million in revenues for 2017 and for 2016, respectively, from Direct Access customers for transmission and delivery charges only.

Total revenues for the three months ended September 30, 2017 increased $31 million compared to the three months ended September 30, 2016, as Total retail revenues increased $27 million while Wholesale and Other revenues were a total of $4 million higher.

The change in Retail revenues resulted largely from the following:

- A $37 million increase resulting from 8.5% greater retail energy deliveries due to favorable weather conditions and increased average usage per customer across all classes. Energy deliveries to residential customers increased 12.3% in the third quarter of 2017 due in part to the effects of weather, as temperatures in 2017 were abnormally warm during the summer cooling season, and customer growth continued. Energy deliveries to commercial customers showed an increase of 6.8% while deliveries to industrial customers increased 6.0%, largely due to strength in the high tech sector; and
- A $3 million increase in various Supplemental tariffs, the largest of which was a $1 million increase due to the accelerated cost recovery of Colstrip; partially offset by
- A $7 million decrease that resulted from customer price changes; and
- A $4 million decrease that resulted from other tariffs, which included $3 million greater estimated refunds under the decoupling mechanism, combined with a variety of smaller items.

Total cooling degree-days for the three months ended September 30, 2017, were up 45% from the level for the three months ended September 30, 2016, 43% above the quarterly average. Total heating degree-days for the three months ended September 30, 2017 were on par with the three months ended September 30, 2016 and the historical average.

The following table indicates the number of heating and cooling degree-days for the three months ended September 30, 2017 and 2016, along with 15-year averages based on weather data provided by the National Weather Service, as measured at Portland International Airport:

	Heating Degree-days			Cooling Degree-days		
	2017	**2016**	**Avg.**	**2017**	**2016**	**Avg.**
July	1	3	9	164	140	163
August	1	3	8	275	224	168
September	76	72	61	132	30	68
Totals for the quarter	78	78	78	571	394	399

Wholesale revenues for the three months ended September 30, 2017 increased $2 million, or 4%, from the three months ended September 30, 2016, and consisted of a $7 million increase related to a 16% increase in average wholesale price partially offset by a $5 million decrease related to a 10% decrease in wholesale sales volume.

Purchased power and fuel expense increased $4 million, or 2%, for the three months ended September 30, 2017 compared with the three months ended September 30, 2016. This change consisted of $3 million related to an increase in total system load combined with $1 million related to an overall increase in the average variable power cost per MWh. The increase in expense due to changes in system load was driven primarily by a 7% increase in retail energy sales to meet summer load requirements. Average variable power cost increased to $30.99 per MWh in the three months ended September 30, 2017 from $30.82 per MWh in the three months ended September 30, 2016.

While the Company generated 78% of its total system load in the three months ended September 30, 2017, compared with 77% in the three months ended September 30, 2016, the average variable cost per MWh of energy generated declined 10%. Included in this percentage was a 21% decrease in the average variable cost per MWh of energy generated from the Company’s natural gas-fired resources due to lower fuel costs, less hedging activity losses, and a 4% increase in the volume of energy obtained from the Company's hydro resources due to more favorable hydroelectric conditions.

Although the Company purchased 22% of its total system load in 2017 compared with 23% in 2016, the average variable power cost per MWh of purchased power increased by 18% due to higher market prices reflecting the increased summer peak demands. A 16% decrease in energy received from the Company's wind generating resources necessitated the purchase of replacement power as a result.

The sources of energy for PGE's total system load, as well as its retail load requirement, were as follows for the periods presented:

	Three Months Ended September 30,			
	2017		2016	
Sources of energy (MWh in thousands):				
Generation:				
Thermal:				
Coal	1,404	24%	1,418	24%
Natural gas	2,442	41	2,243	39
Total thermal	3,846	65	3,661	63
Hydro	277	5	267	4
Wind	480	8	570	10
Total generation	4,603	78	4,498	77
Purchased power:				
Term	908	15	913	16
Hydro	332	6	322	6
Wind	83	1	91	1
Total purchased power	1,323	22	1,326	23
Total system load	5,926	100%	5,824	100%
Less: wholesale sales	(1,224)		(1,360)	
Retail load requirement	4,702		4,464	

Energy received from PGE-owned wind generating resources decreased 16% in the three months ended September 30, 2017 compared with the same period of 2016 as a result of less favorable wind conditions. Energy received from these wind generating resources represented 10% and 13% of the Company's retail load requirements for the three months ended September 30, 2017 and 2016, respectively. Due to more favorable hydroelectric conditions, energy received from hydro resources during the three months ended September 30, 2017, from both PGE-owned generating plants and purchased from mid-Columbia projects, increased 3% compared with the same period of 2016, and represented 13% of the Company's retail load requirement for the three months ended September 30, 2017 and 2016, respectively.

The following table presents the actual April-to-September 2017 and 2016 runoff at particular points of major rivers relevant to PGE's hydro resources:

Location	Actual Runoff as a Percent of Normal*	
	2017	2016
Columbia River at The Dalles, Oregon	98%	89%
Mid-Columbia River at Grand Coulee, Washington	98	91
Clackamas River at Estacada, Oregon	97	71
Deschutes River at Moody, Oregon	98	91

* Volumetric water supply forecasts and historical 30-year averages (as measured over the period from 1981 through 2010) for the Pacific Northwest region are prepared by the Northwest River Forecast Center in conjunction with the Natural Resources Conservation Service and other cooperating agencies.

Actual NVPC for the three months ended September 30, 2017 increased $2 million when compared with the three months ended September 30, 2016. The increase was driven by a 1% increase in the average variable power cost per MWh, and a 2% increase in total system load. The increase in wholesale revenues was driven primarily by a 16% increase in the average wholesale sales price, offset slightly by a 10% decrease in wholesale sales volume. For the three months ended September 30, 2017, actual NVPC was $22 million above the baseline as the Company met higher customer load, driven by historically hot weather, with energy purchased at super peak prices in the open market in addition to the cost of foregoing the use of Company resources in order to maintain mandated reliability reserves. For the three months ended September 30, 2016, actual NVPC was $3 million above baseline NVPC.

Generation, transmission and distribution expense increased $4 million, or 6%, in the three months ended September 30, 2017 compared with the three months ended September 30, 2016, driven primarily by $2 million of operating expense for Carty (placed in service July 29, 2016).

Administrative and other expense increased $1 million, or 2%, in the three months ended September 30, 2017 compared with the three months ended September 30, 2016. The increase was primarily due to a $2 million increase in employee incentives, offset by decreases in other miscellaneous expenses.

Depreciation and amortization expense increased $8 million in the three months ended September 30, 2017 compared with the three months ended September 30, 2016. The increase was driven by higher depreciation expense of $6 million resulting from capital additions, $2 million of which was due to Carty going into service in July 2016, and a $1 million decrease in the amortization credit related to the Trojan spent fuel refund to customers, which is also reflected in revenues as increases or decreases in expense resulting from amortization of regulatory assets or liabilities are directly offset in revenues.

Interest expense, net increased $2 million, or 7%, in the three months ended September 30, 2017 compared with the three months ended September 30, 2016, primarily due to a lower Allowance for borrowed funds used during construction, as a result of Carty going into service in July 2016.

Other income, net increased $2 million for the three months ended September 30, 2017 compared with the three months ended September 30, 2016, due largely to interest income on various regulatory assets and unrealized gains on trust assets.

Income tax expense was $13 million in the three months ended September 30, 2017 compared with $6 million in the three months ended September 30, 2016, with effective tax rates of 24.5% and 15.0%, respectively. The increase in income tax expense and effective tax rate was primarily driven by higher pre-tax income and lower PTCs.

Nine Months Ended September 30, 2017 Compared with the Nine Months Ended September 30, 2016

Revenues, energy deliveries (presented in MWh), and the average number of retail customers consist of the following for the periods presented:

	Nine Months Ended September 30,			
	2017		2016	
Revenues * (dollars in millions):				
Retail:				
Residential	$ 715	48%	$ 648	47%
Commercial	501	34	492	35
Industrial	158	11	153	11
Subtotal	1,374	93	1,293	93
Other retail revenues, net	7	—	5	—
Total retail revenues	1,381	93	1,298	93
Wholesale revenues	79	5	74	5
Other operating revenues	34	2	27	2
Total revenues	$ 1,494	100%	$ 1,399	100%
Energy deliveries (MWh in thousands):				
Retail:				
Residential	5,826	34%	5,278	32%
Commercial	5,193	30	5,148	31
Industrial	2,187	13	2,168	13
Subtotal	13,206	77	12,594	76
Direct access:				
Commercial	472	3	403	2
Industrial	1,046	6	907	6
Subtotal	1,518	9	1,310	8
Total retail energy deliveries	14,724	86	13,904	84
Wholesale energy deliveries	2,336	14	2,621	16
Total energy deliveries	17,060	100%	16,525	100%
Average number of retail customers:				
Residential	761,028	88%	751,198	88%
Commercial	107,296	12	106,458	12
Industrial	198	—	193	—
Direct access	547	—	377	—
Total	869,069	100%	858,226	100%

* Includes revenues from customers who purchase their energy from the Company as well as $28 million in revenues for 2017 and $22 million for 2016 from Direct Access customers for transmission and delivery charges only.

Total revenues for the nine months ended September 30, 2017 increased $95 million, or 7%, compared to the nine months ended September 30, 2016, consisting primarily of an $83 million increase in Total retail revenues.

The change in Retail revenues consisted of the following contributing factors:

- A $76 million increase due to a 5.9% increase in retail energy deliveries due largely to the effects of weather on electricity demand. Considerably cooler temperatures in the first half of the year than experienced in 2016 combined with warmer temperatures in the summer cooling season, when air conditioning loads influence customer demand, both drove deliveries higher in 2017 than in 2016;

- A $7 million net increase from an average price increase of 0.5% over 2016 levels. Price changes, as authorized by the OPUC, include Carty going into service in mid-2016 and reflect a reduction as a result of lower NVPC as filed in the 2017 AUT; and
- A $3 million increase resulted from other tariffs, which included a $4 million increase in estimated collections under the decoupling mechanism; partially offset by
- A $3 million decrease from supplemental tariffs, due in part to the $9 million timing difference related to the Trojan spent fuel refund to customers, as the refund, offset in Depreciation and amortization, temporarily suspended during the first seven months of 2016, has resumed, partially offset by a $4 million increase related to the accelerated cost recovery of Colstrip, and various smaller items.

Total heating degree-days for the nine months ended September 30, 2017 were up 42% from those for the nine months ended September 30, 2016 and 11% above average. Total cooling degree-days for the nine months ended September 30, 2017 were 28% above those for the nine months ended September 30, 2016, and 49% above average.

The following table indicates the number of heating and cooling degree-days for the nine months ended September 30, 2017 and 2016, along with 15-year averages based on weather data provided by the National Weather Service, as measured at Portland International Airport:

	Heating Degree-days			Cooling Degree-days		
	2017	2016	Avg.	2017	2016	Avg.
First quarter	2,171	1,585	1,867	—	—	—
Second quarter	686	403	689	129	154	70
Third quarter	78	78	78	571	394	399
Year-to-date	2,935	2,066	2,634	700	548	469

Wholesale revenues for the nine months ended September 30, 2017 increased $5 million, or 7%, from the nine months ended September 30, 2016, and consisted of $13 million related to a 19% increase in wholesale sales volume partially offset by $8 million related to an 11% decrease in wholesale prices.

Other operating revenues increased $7 million as the sale of gas not needed to fuel the Company's generating facilities accounted for the majority of the increase.

Purchased power and fuel expense decreased $12 million, or 3%, for the nine months ended September 30, 2017 compared with the nine months ended September 30, 2016, and consisted of $22 million related to a 5% decrease in the average variable power cost per MWh, partially offset by $10 million related to a 2% increase in total system load.

The decrease in the average variable power cost to $26.93 per MWh in the nine months ended September 30, 2017 from $28.28 per MWh in the nine months ended September 30, 2016, was driven primarily by a 10% reduction in the average variable power cost per MWh for purchased power due to lower market prices. This was partially offset by the purchase of replacement power due to 18% less energy received from the Company's wind generating resources.

The $10 million increase related to total system load in the nine months ended September 30, 2017 in comparison to the nine months ended September 30, 2016 was driven primarily by a 7% increase in energy obtained from purchased power in response to higher weather-driven loads, as well as the purchase of replacement energy due to an 18% reduction in energy deliveries from the Company's wind generating resources due to unfavorable weather conditions. This was partially offset by a 12% increase in energy obtained from the Company's hydro resources due to more favorable hydroelectric conditions.

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The sources of energy for PGE’s total system load, as well as its retail load requirement, were as follows for the periods presented:

	Nine Months Ended September 30,			
	2017		2016	
Sources of energy (MWh in thousands):				
Generation:				
Thermal:				
Coal	2,571	16%	2,535	16%
Natural gas	3,982	24	4,017	25
Total thermal	6,553	40	6,552	41
Hydro	1,353	8	1,214	7
Wind	1,283	8	1,559	10
Total generation	9,189	56	9,325	58
Purchased power:				
Term	5,705	35	5,355	33
Hydro	1,332	8	1,160	7
Wind	207	1	241	2
Total purchased power	7,244	44	6,756	42
Total system load	16,433	100%	16,081	100%
Less: wholesale sales	(2,336)		(2,621)	
Retail load requirement	14,097		13,460	

Energy received from PGE-owned wind generating resources decreased 18% in the nine months ended September 30, 2017 compared with the same period of 2016 as a result of less favorable wind conditions. Energy received from these wind generating resources represented 9% and 12% of the Company’s retail load requirements for the nine months ended September 30, 2017 and 2016, respectively. Due to more favorable hydroelectric conditions, energy received from hydro resources during the nine months ended September 30, 2017, from both PGE-owned generating plants and purchased from mid-Columbia projects, increased 13% compared with the same period of 2016, and represented 19% and 18% of the Company’s retail load requirement for the nine months ended September 30, 2017 and 2016, respectively.

Actual NVPC for the nine months ended September 30, 2017 decreased $17 million when compared with the nine months ended September 30, 2016. The decrease in purchased power and fuel was driven by a 5% decrease in the average variable power cost per MWh, partially offset by a 2% increase in total system load. The overall decrease in Actual NVPC was also driven by a 7% increase in wholesale revenues. The change in wholesale revenues was due mostly to a 19% increase in wholesale sales price, partially offset by an 11% decrease in sales volume. For the nine months ended September 30, 2017 and 2016, actual NVPC was $14 million above and $3 million below baseline NVPC, respectively.

Generation, transmission and distribution expense increased $36 million, or 18%, in the nine months ended September 30, 2017 compared with the nine months ended September 30, 2016 primarily related to $13 million higher operating expense for Carty (placed in service July 29, 2016), $12 million higher overall storm restoration costs, and $5 million higher maintenance and overhaul expense.

Administrative and other expense increased $12 million, or 6%, in the nine months ended September 30, 2017 compared with the nine months ended September 30, 2016. The increase was primarily due to $6 million higher employee incentives and $3 million higher legal costs for Carty.

Depreciation and amortization expense increased $13 million in the nine months ended September 30, 2017 compared with the nine months ended September 30, 2016. The increase was primarily due to higher depreciation expense of $8 million driven by the Carty plant going into service in July 2016, $13 million higher depreciation expense due to other capital additions, partially offset by a $9 million amortization credit in 2017 related to the Trojan spent fuel refund to customers, which is also reflected in reduced revenues.

Taxes other than income taxes increased $5 million, or 6%, in the nine months ended September 30, 2017 compared to the nine months ended September 30, 2016, driven by $3 million higher property taxes, due largely to the addition of Carty, and a $2 million increase in FICA taxes due to the combination of increased headcount, higher FICA limits and rates, annual pay increases, and incremental labor required as a result of the numerous storms and resulting restoration activities during 2017.

Interest expense, net increased $8 million, or 10%, in the nine months ended September 30, 2017 compared with the nine months ended September 30, 2016, primarily due to a lower allowance for borrowed funds used during construction, as a result of Carty going into service in July 2016.

Other income, net was $13 million in the nine months ended September 30, 2017 compared with $19 million in the nine months ended September 30, 2016. The change was due to a $10 million decrease in the allowance for equity funds used during construction, primarily related to the Carty project, partially offset by higher gains on the non-qualified benefit trust assets.

Income tax expense was $46 million in the nine months ended September 30, 2017 compared with $32 million in the nine months ended September 30, 2016, with effective tax rates of 24.1% and 19.5%, respectively. The increase in income tax expense and the effective tax rate was driven by higher pre-tax income, the tax effect of lower AFDC equity, and a decrease in PTCs, partially offset by an increase in the domestic production activity deduction.

Liquidity and Capital Resources

Capital Requirements

The following table presents PGE's estimated capital expenditures and contractual maturities of long-term debt for 2017 through 2021 (in millions, excluding AFDC):

	2017	2018	2019	2020	2021
Ongoing capital expenditures (1)	$ 486	$ 535	$ 443	$ 451	$ 440
Customer information system (2)	47	16	—	—	—
Total capital expenditures	$ 533 (3)	$ 551	$ 443	$ 451	$ 440
Long-term debt maturities	$ 150	$ —	$ 300	$ —	$ 160

(1) Consists primarily of upgrades to, and replacement of, generation, transmission, and distribution infrastructure, as well as new customer connections.
(2) As of December 31, 2016, total capital expenditures for the Customer information project was $65 million, excluding AFDC.
(3) Includes preliminary engineering and removal costs, which are included in other net operating activities in the condensed consolidated statements of cash flows.

For a discussion concerning PGE's ability to fund its future capital requirements, see *"Debt and Equity Financings"* in this Item 2.

Liquidity

PGE’s access to short-term debt markets, including revolving credit from banks, helps provide necessary liquidity to support the Company’s current operating activities, including the purchase of power and fuel. Long-term capital requirements are driven largely by capital expenditures for distribution, transmission, and generation facilities to support both new and existing customers, as well as debt refinancing activities. PGE’s liquidity and capital requirements can also be significantly affected by other working capital needs, including margin deposit requirements related to wholesale market activities, which can vary depending upon the Company’s forward positions and the corresponding price curves.

The following summarizes PGE’s cash flows for the periods presented (in millions):

	Nine Months Ended September 30,	
	2017	**2016**
Cash and cash equivalents, beginning of period	$ 6	$ 4
Net cash provided by (used in):		
Operating activities	519	497
Investing activities	(369)	(454)
Financing activities	(67)	41
Increase in cash and cash equivalents	83	84
Cash and cash equivalents, end of period	$ 89	$ 88

Cash Flows from Operating Activities—Cash flows from operating activities are generally determined by the amount and timing of cash received from customers and payments made to vendors, with adjustments for certain non-cash items, such as depreciation and amortization, deferred income taxes, and pension and other postretirement benefit costs included in net income during a given period. Net cash flows from operating activities for the nine months ended September 30, 2017 increased $22 million when compared with the nine months ended September 30, 2016. Included in the change were a number of relatively small, somewhat offsetting, factors such as:

- A $48 million increase from the combination of higher Net income, increases in non-cash expenses for Depreciation and amortization and Deferred taxes, increases from Other non-cash income and expenses, and a decrease in the non-cash credit to income for the Allowance for equity funds used during construction as Carty was placed in service in July 2016, net of the overall decrease resulting from Decoupling deferrals; and
- A $14 million net increase from a combination of changes in Other working capital items, net and Other, net adjustments to net income; partially offset by
- A $21 million smaller decrease in Margin deposits; and
- A $17 million reduction in the comparative quarter over quarter increase in Accounts payable and accrued liabilities.

Cash provided by operations includes the recovery in customer prices of non-cash charges for depreciation and amortization. PGE estimates that such charges in 2017 will range from $340 million to $350 million. Combined with other sources, total cash expected to be provided by operations is estimated to range from $515 million to $565 million.

Cash Flows from Investing Activities—Cash flows used in investing activities consist primarily of capital expenditures related to new construction and improvements to PGE’s generation facilities and transmission and distribution systems. Net cash used in investing activities for the nine months ended September 30, 2017 decreased $85 million when compared with the nine months ended September 30, 2016, largely due to the lower level of capital expenditures resulting from the completion of Carty during 2016.

The Company plans to make capital expenditures of $533 million, excluding AFDC, in 2017, which it expects to fund with cash to be generated from operations during 2017, as discussed above, as well as with proceeds received from the issuances of debt securities. For additional information, see *"Debt and Equity Financings"* in this Liquidity and Capital Resources section of Item 2.

Cash Flows from Financing Activities—Financing activities provide supplemental cash for both day-to-day operations and capital requirements as needed. During the nine months ended September 30, 2017, a net use of cash resulted from financing activities primarily for the payment of dividends of $87 million and, as further described in *"Debt and Equity Financings"* in this Liquidity section of Item 2, the repayment of $50 million of term loans, net of the issuance of $75 million of FMBs. During the nine months ended September 30, 2016, net cash provided by financing activities consisted primarily of $265 million received from the issuances of FMBs and borrowing under an unsecured credit agreement, partially offset by repayment of long-term debt of $133 million and the payment of dividends of $82 million.

Dividends on Common Stock

While PGE expects to pay regular quarterly dividends on its common stock, the declaration of any dividends remains at the discretion of the Company's Board of Directors. The amount of any dividend declaration depends upon factors that the Board of Directors deems relevant, which may include, among other things, PGE's results of operations and financial condition, future capital expenditures and investments, and applicable regulatory and contractual restrictions.

Common stock dividends declared during 2017 consist of the following:

Declaration Date	Record Date	Payment Date	Dividends Declared Per Common Share
February 15, 2017	March 27, 2017	April 17, 2017	$0.32
April 26, 2017	June 26, 2017	July 17, 2017	0.34
July 26, 2017	September 25, 2017	October 16, 2017	0.34
October 25, 2017	December 26, 2017	January 16, 2018	0.34

Debt and Equity Financings

PGE's ability to secure sufficient long-term capital at a reasonable cost is determined by its financial performance and outlook, its credit ratings, its capital expenditure requirements, alternatives available to investors, market conditions, and other factors. Management believes that the availability of its revolving credit facility, the expected ability to issue long-term debt and equity securities, and cash expected to be generated from operations provide sufficient cash flow and liquidity to meet the Company's anticipated capital and operating requirements for the foreseeable future. However, the Company's ability to issue long-term debt and equity could be adversely affected by changes in capital market conditions.

For 2017, PGE expects to fund estimated capital expenditures and maturities of long-term debt with cash from operations (which is expected to range from $515 million to $565 million), issuances of debt securities of up to $225 million, and the issuance of commercial paper, as needed. The actual timing and amount of any such issuances of debt and commercial paper will be dependent upon the timing and amount of capital expenditures and maturities of long-term debt.

Short-term Debt. PGE has approval from the FERC to issue short-term debt up to a total of $900 million through February 6, 2018.

As of September 30, 2017, PGE had a $500 million revolving credit facility scheduled to expire in November 2020. The revolving credit facility supplements operating cash flows and provides a primary source of liquidity. Pursuant to the terms of the agreement, the revolving credit facility may be used as backup for commercial paper borrowings, to permit the issuance of standby letters of credit, and for general corporate purposes. PGE may borrow for one, two, three, or six months at a fixed interest rate established at the time of the borrowing, or at a variable interest rate for any period up to the then remaining term of the applicable credit facility.

The Company has a commercial paper program under which it may issue commercial paper for terms of up to 270 days, limited to the unused amount of credit under the revolving credit facility.

Under the revolving credit facility, as of September 30, 2017, since PGE had no borrowings outstanding, and no commercial paper or letters of credit issued, the aggregate unused available credit capacity under the revolving credit facility was $500 million.

In addition, PGE has four letter of credit facilities under which the Company can request letters of credit for original terms not to exceed one year. These facilities provide for a total capacity of $220 million. The issuance of such letters of credit is subject to the approval of the issuing institution. Under these facilities, letters of credit for a total of $54 million were outstanding as of September 30, 2017.

Long-term Debt. As of September 30, 2017, total long-term debt outstanding, net of $9 million of unamortized debt expense, was $2,377 million, with $100 million scheduled maturities classified as current.

On August 2, 2017, PGE entered into a bond purchase agreement to issue First Mortgage Bonds (FMBs) in the amount of $225 million at an interest rate of 3.98%. Under this agreement, PGE drew $75 million in August, with a maturity in 2048, and plans to draw $150 million in November 2017, with a maturity in 2047.

In May 2016, PGE entered into an unsecured credit agreement with certain financial institutions, under which the Company had the opportunity to obtain three separate term loans in an aggregate principal amount of up to $200 million by October 31, 2016. Under the agreement, PGE obtained three separate loans totaling $150 million. On August 21, 2017, the Company repaid one of the loans in the amount of $50 million. The remaining $100 million is due and payable on or before the November 30, 2017 credit agreement expiration date.

Capital Structure. PGE's financial objectives include maintaining a common equity ratio (common equity to total consolidated capitalization, including any current debt maturities) of approximately 50% over time. Achievement of this objective helps the Company maintain investment grade credit ratings and facilitates access to long-term capital at favorable interest rates. The Company's common equity ratio was 50.3% and 49.4% as of September 30, 2017 and December 31, 2016, respectively.

Credit Ratings and Debt Covenants

PGE's secured and unsecured debt is rated investment grade by Moody's Investors Service (Moody's) and S&P Global Ratings (S&P), with current credit ratings and outlook as follows:

	Moody's	**S&P**
First Mortgage Bonds	A1	A-
Issuer rating	A3	BBB
Commercial paper	P-2	A-2
Outlook	Stable	Positive

Should Moody's and/or S&P reduce their credit rating on PGE's unsecured debt below investment grade, the Company could be subject to requests by certain of its wholesale, commodity, and transmission counterparties to post additional performance assurance collateral in connection with its price risk management activities. The performance assurance collateral can be in the form of cash deposits or letters of credit, depending on the terms of the underlying agreements, are based on the contract terms and commodity prices, and can vary from period to period. Cash deposits provided as collateral are classified as Margin deposits, which is included in Other current assets on PGE’s condensed consolidated balance sheets, while any letters of credit issued are not reflected on the Company’s condensed consolidated balance sheets.

As of September 30, 2017, PGE had posted $22 million of collateral with these counterparties, consisting of $4 million in cash and $18 million in letters of credit. Based on the Company’s energy portfolio, estimates of energy market prices, and the level of collateral outstanding as of September 30, 2017, the amount of additional collateral that could be requested upon a single agency downgrade to below investment grade was $70 million, and decreases to $31 million by December 31, 2017 and to $10 million by December 31, 2018. The amount of additional collateral that could be requested upon a dual agency downgrade to below investment grade was $150 million at September 30, 2017, and decreases to $106 million by December 31, 2017 and to $73 million by December 31, 2018.

PGE’s financing arrangements do not contain ratings triggers that would result in the acceleration of required interest and principal payments in the event of a ratings downgrade. However, the cost of borrowing and issuing letters of credit under the credit facility would increase.

The issuance of FMBs requires that PGE meet earnings coverage and security provisions set forth in the Indenture of Mortgage and Deed of Trust (Indenture) securing the bonds. PGE estimates that on September 30, 2017, under the most restrictive issuance test in the Indenture, the Company could have issued up to $1,020 million of additional FMBs. Any issuances of FMBs would be subject to market conditions and amounts could be further limited by regulatory authorizations or by covenants and tests contained in other financing agreements. PGE also has the ability to release property from the lien of the Indenture under certain circumstances, including bond credits, deposits of cash, or certain sales, exchanges, or other dispositions of property.

PGE’s credit facility contains customary covenants and credit provisions, including a requirement that limits consolidated indebtedness, as defined in the credit agreements, to 65.0% of total capitalization (debt-to-total capital ratio). As of September 30, 2017, the Company’s debt-to-total capital ratio, as calculated under the credit agreement, was 51.3%.

Off-Balance Sheet Arrangements

PGE has no off-balance sheet arrangements, other than outstanding letters of credit from time to time, that have, or are reasonably likely to have, a material current or future effect on its consolidated financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Contractual Obligations

PGE’s contractual obligations for 2017 and beyond are set forth in Part II, Item 7 of the Company’s Annual Report on Form 10-K for the year ended December 31, 2016, filed with the SEC on February 17, 2017. For such obligations, there have been no material changes outside the ordinary course of business, as of September 30, 2017, except for the First Mortgage Bond long-term debt issuance and the partial repayment under the unsecured credit agreement discussed in the *“Debt and Equity Financings”* section in this Item 2.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

PGE is exposed to various forms of market risk, consisting primarily of fluctuations in commodity prices, foreign currency exchange rates, and interest rates, as well as credit risk. There have been no material changes to market risks affecting the Company from those set forth in Part II, Item 7A of the Company’s Annual Report on Form 10-K for the year ended December 31, 2016, filed with the SEC on February 17, 2017.

Item 4. Controls and Procedures.

Disclosure Controls and Procedures

PGE’s management, under the supervision and with the participation of its Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the Company’s disclosure controls and procedures as required by Exchange Act Rule 13a-15(b) as of the end of the period covered by this report. Based on that evaluation, PGE's Chief Executive Officer and Chief Financial Officer have concluded that, as of September 30, 2017, these disclosure controls and procedures were effective.

Changes in Internal Control over Financial Reporting

There were no changes in PGE's internal control over financial reporting that occurred during the period covered by this quarterly report that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II - OTHER INFORMATION

Item 1. Legal Proceedings.

For further information regarding PGE's legal proceedings, see "*Legal Proceedings*" set forth in Part I, Item 3 of the Company's Annual Report on Form 10-K for the year ended December 31, 2016, filed with the SEC on February 17, 2017 and Part II, Item 1 of the Company's Quarterly Report on Form 10-Q for the quarterly periods ended March 31, 2017 and June 30, 2017, filed with the SEC on April 28, 2017 and July 28, 2017, respectively.

Dreyer, Gearhart and Kafoury Bros., LLC v. Portland General Electric Company, Marion County Circuit Court; and Morgan v. Portland General Electric Company, Marion County Circuit Court.

On March 16, 2016, the Marion County Circuit Court entered a general judgment that granted the Company's motion for summary judgment and dismissed all claims by the plaintiffs. On April 14, 2016, the plaintiffs appealed the general judgment of the Circuit Court in the Court of Appeals for the State of Oregon. Briefing is now complete, with a Court of Appeals decision pending.

In the Matter of an Arbitration Under the Rules of the International Chamber of Commerce's Court of Arbitration, International Chamber of Commerce's Court of Arbitration.

In 2013, PGE entered into an agreement (Construction Agreement) with its engineering, procurement and construction contractor - Abeinsa EPC LLC, Abener Construction Services, LLC, Teyma Construction USA, LLC, and Abeinsa Abener Teyma General Partnership, an affiliate of Abengoa S.A. (collectively, the "Contractor") - for the construction of Carty. Liberty Mutual Insurance Company and Zurich American Insurance Company (collectively, the "Sureties") provided a performance bond of $145.6 million (Performance Bond) under the Construction Agreement.

On December 18, 2015, the Company declared the Contractor in default under the Construction Agreement and terminated the Construction Agreement, after which PGE, in consultation with the Sureties, brought on new contractors and construction resumed.

On December 31, 2015, Abengoa S.A. filed a Request for Arbitration in the International Chamber of Commerce's Court of Arbitration (ICC arbitration) seeking a declaration that it owes nothing under the Guaranty it provided to PGE, pursuant to which it guaranteed performance under the Construction Agreement for Carty.

PGE disagreed with the assertions in the Request for Arbitration and in February 2016 filed a complaint and motion for preliminary injunction in the U.S. District Court for the District of Oregon seeking to have the arbitration claim dismissed on the grounds that the Company had not made a demand under the Guaranty, and therefore the matter was not ripe for arbitration. The Contractor has been joined as a party to the arbitration and is seeking damages of $117 million based on a claim that PGE wrongfully terminated the Construction Agreement. The Contractor is also seeking estimated damages of $44 million based on a claim that PGE failed to disclose to the Contractor, in connection with the Contractor's bid submitted pursuant to the Company's request for proposals, certain information regarding union labor productivity rates in eastern Oregon, and that this alleged failure caused the Contractor to submit a bid with a contract price that was lower than the contract price that would have been submitted had Contractor known such information. PGE disagrees with both of these claims.

A hearing before the ICC arbitration panel to determine jurisdictional matters, originally scheduled for late October 2017, was rescheduled to the spring of 2018, due to the addition of the Sureties to the ICC arbitration proceeding, as a result of the Ninth Circuit Court of Appeals (Ninth Circuit) decision and denial of the appeal in August 2017, referenced in the U.S. District Court cases described below.

Portland General Electric Company v. Liberty Mutual Insurance Company and Zurich American Insurance Company, U.S. District Court of the District of Oregon.

On July 27, 2016, the judge denied the Sureties' motion to stay the case in favor of a pending ICC arbitration (see case above) and granted PGE's motion for an injunction prohibiting the Sureties from pursuing any Performance Bond claims in the ICC arbitration. The Sureties appealed the rulings to the Ninth Circuit and asked the U.S. District Court to stay the proceedings pending resolution of the appeal.

On July 10, 2017, the Ninth Circuit overturned the U.S. District Court ruling and held that the ICC arbitration panel has jurisdiction to determine what parties can be joined, and what claims can be presented, in the ICC arbitration.

On July 24, 2017, PGE filed a petition requesting en banc rehearing with the Ninth Circuit. On August 28, 2017, the Ninth Circuit issued notice denying the request for rehearing. As a result, this case is stayed, pending the ICC arbitration, discussed above.

Portland General Electric Company v. Abeinsa EPC LLC, Abener Construction Services, LLC (formerly known as Abener Engineering and Construction Services, LLC), Teyma Construction USA LLC, and Abeinsa Abener Teyma General Partnership, U.S. District Court of the District of Oregon.

On October 21, 2016, PGE filed a complaint in the U.S. District Court against Abeinsa for failure to satisfy its obligations under the Construction Agreement. PGE is seeking damages from Abeinsa in excess of $200 million for: i) costs incurred to complete construction of Carty, settle claims with unpaid contractors and vendors and remove liens; and ii) damages in excess of the construction costs, including a project management fee, liquidated damages under the Construction Agreement, legal fees and costs, damages due to delay of the project, warranty costs, and interest.

On March 21, 2017, the judge entered an order staying the case. With the August 28, 2017 Ninth Circuit denial of rehearing referenced in the preceding case, the ICC arbitration panel will determine whether these claims must be presented in the ICC arbitration.

Deschutes River Alliance v. Portland General Electric Company, U.S. District Court of the District of Oregon.

On August 12, 2016, the Deschutes River Alliance (DRA) filed a lawsuit against the Company in U.S. District Court. DRA's claims seek injunctive and declaratory relief against PGE under the Clean Water Act (CWA) related to alleged past and continuing violations of the CWA. The court denied PGE's motion to dismiss and PGE then submitted a request on April 6, 2017, for interlocutory appeal to the Ninth Circuit of the order dismissing its motion to dismiss. The request also included a motion for stay of the lower court proceeding. The parties agreed to defer decision on the motion for stay pending a ruling on PGE's request to file the interlocutory appeal. On May 19, 2017, the District Court granted PGE's request to file the interlocutory appeal, but the Ninth Circuit denied the appeal on August 14, 2017.

The parties are engaged in settlement discussions and have filed a joint motion, which was granted September 11, 2017, to continue the stay until either party finds settlement negotiations unfruitful.

Item 1A. Risk Factors.

There have been no material changes to PGE's risk factors set forth in Part I, Item 1A of the Company's Annual Report on Form 10-K for the year ended December 31, 2016, filed with the SEC on February 17, 2017.

Item 6. Exhibits.

Exhibit Number	Description
3.1	Third Amended and Restated Articles of Incorporation of Portland General Electric Company (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed May 9, 2014).
3.2	Tenth Amended and Restated Bylaws of Portland General Electric Company (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K filed May 9, 2014).
31.1	Certification of Chief Executive Officer.
31.2	Certification of Chief Financial Officer.
32	Certifications of Chief Executive Officer and Chief Financial Officer.
4.1	Seventy-third Supplemental Indenture dated August 1, 2017, between the Company and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to the Company's current report on Form 8-K filed on August 3, 2017).
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

Certain instruments defining the rights of holders of other long-term debt of the Company are omitted pursuant to Item 601(b)(4)(iii)(A) of Regulation S-K because the total amount of securities authorized under each such omitted instrument does not exceed 10% of the total consolidated assets of the Company and its subsidiaries. The Company hereby agrees to furnish a copy of any such instrument to the SEC upon request.

SIGNATURE

Pursuant to the 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.

PORTLAND GENERAL ELECTRIC COMPANY
(Registrant)

Date: October 26, 2017

By: /s/ James F. Lobdell
James F. Lobdell
Senior Vice President of Finance,
Chief Financial Officer and Treasurer
(duly authorized officer and principal financial officer)

Exhibit 31.1

CERTIFICATION

I, James J. Piro, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Portland General Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the period presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 26, 2017

By: /s/ James J. Piro

James J. Piro

President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, James F. Lobdell, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Portland General Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the period presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date:	October 26, 2017	By:	/s/ James F. Lobdell
			James F. Lobdell
			Senior Vice President of Finance, *Chief Financial Officer and Treasurer*

Exhibit 32

CERTIFICATIONS PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

We, James J. Piro, President and Chief Executive Officer, and James F. Lobdell, Senior Vice President of Finance, Chief Financial Officer and Treasurer, of Portland General Electric Company (the "Company"), hereby certify that the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2017, as filed with the Securities and Exchange Commission on October 27, 2017 pursuant to Section 13(a) of the Securities Exchange Act of 1934 (the "Report"), fully complies with the requirements of that section.

We further certify that the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ James J. Piro	/s/ James F. Lobdell
James J. Piro	James F. Lobdell
President and Chief Executive Officer	*Senior Vice President of Finance, Chief Financial Officer and Treasurer*

Date:	October 26, 2017	Date:	October 26, 2017