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 **June 30, 2015**

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, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer [x]	Accelerated filer [ ]	Non-accelerated filer [ ]	Smaller reporting company [ ]

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 July 22, 2015 is 88,765,889 shares.

PORTLAND GENERAL ELECTRIC COMPANY
FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED June 30, 2015

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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
Biglow Canyon	Biglow Canyon Wind Farm
Carty	Carty Generating Station natural gas-fired generating plant
Colstrip	Colstrip Units 3 and 4 coal-fired generating plant
CWIP	Construction work-in-progress
EFSA	Equity forward sale agreement
EPA	United States Environmental Protection Agency
ESS	Electricity Service Supplier
FERC	Federal Energy Regulatory Commission
FMBs	First Mortgage Bonds
IRP	Integrated Resource Plan
kV	Kilovolt = one thousand volts of electricity
Moody's	Moody's Investors Service
MW	Megawatts
MWa	Average megawatts
MWh	Megawatt hours
NVPC	Net Variable Power Costs
OPUC	Public Utility Commission of Oregon
PCAM	Power Cost Adjustment Mechanism
PW1	Port Westward Unit 1 natural gas-fired generating plant
PW2	Port Westward Unit 2 natural gas-fired flexible capacity generating plant
S&P	Standard and Poor's Ratings Services
SEC	United States Securities and Exchange Commission
Tucannon River	Tucannon River Wind Farm
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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Revenues, net	$ 450	$ 423	$ 923	$ 916
Operating expenses:				
Purchased power and fuel	148	142	309	326
Generation, transmission and distribution	66	67	128	121
Administrative and other	60	56	120	110
Depreciation and amortization	76	73	151	148
Taxes other than income taxes	28	27	58	55
Total operating expenses	378	365	766	760
Income from operations	72	58	157	156
Interest expense, net	28	23	58	48
Other income:				
Allowance for equity funds used during construction	5	9	9	15
Miscellaneous income, net	1	1	2	—
Other income, net	6	10	11	15
Income before income tax expense	50	45	110	123
Income tax expense	15	10	25	30
Net income and Comprehensive income	$ 35	$ 35	$ 85	$ 93
Weighted-average shares outstanding (in thousands):				
Basic	80,745	78,183	79,515	78,154
Diluted	80,745	80,051	79,515	79,742
Earnings per share:				
Basic	$ 0.44	$ 0.44	$ 1.07	$ 1.19
Diluted	$ 0.44	$ 0.43	$ 1.07	$ 1.16
Dividends declared per common share	$ 0.300	$ 0.280	$ 0.580	$ 0.555

See accompanying notes to condensed consolidated financial statements.

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

	June 30, 2015		December 31, 2014	
ASSETS				
Current assets:				
Cash and cash equivalents	$	122	$	127
Accounts receivable, net		122		149
Unbilled revenues		87		93
Inventories		101		82
Regulatory assets—current		117		133
Other current assets		97		115
Total current assets		**646**		**699**
Electric utility plant, net		5,874		5,679
Regulatory assets—noncurrent		552		494
Nuclear decommissioning trust		40		90
Non-qualified benefit plan trust		35		32
Other noncurrent assets		51		48
Total assets	**$**	**7,198**	**$**	**7,042**

See accompanying notes to condensed consolidated financial statements.

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

	June 30, 2015	December 31, 2014
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 125	$ 156
Liabilities from price risk management activities—current	101	106
Current portion of long-term debt	55	375
Accrued expenses and other current liabilities	228	236
Total current liabilities	**509**	**873**
Long-term debt, net of current portion	2,204	2,126
Regulatory liabilities—noncurrent	923	906
Deferred income taxes	648	625
Unfunded status of pension and postretirement plans	243	237
Liabilities from price risk management activities—noncurrent	187	122
Asset retirement obligations	135	116
Non-qualified benefit plan liabilities	105	105
Other noncurrent liabilities	23	21
Total liabilities	**4,977**	**5,131**
Commitments and contingencies (see notes)		
Equity:		
Preferred stock, no par value, 30,000,000 shares authorized; none issued and outstanding as of June 30, 2015 and December 31, 2014	—	—
Common stock, no par value, 160,000,000 shares authorized; 88,765,629 and 78,228,339 shares issued and outstanding as of June 30, 2015 and December 31, 2014, respectively	1,191	918
Accumulated other comprehensive loss	(7)	(7)
Retained earnings	1,037	1,000
Total equity	**2,221**	**1,911**
Total liabilities and equity	**$ 7,198**	**$ 7,042**

See accompanying notes to condensed consolidated financial statements.

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

	Six Months Ended June 30,	
	2015	**2014**
Cash flows from operating activities:		
Net income	$ 85	$ 93
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	151	148
Increase (decrease) in net liabilities from price risk management activities	63	(84)
Regulatory deferrals—price risk management activities	(63)	84
Deferred income taxes	22	20
Pension and other postretirement benefits	19	17
Allowance for equity funds used during construction	(9)	(15)
Regulatory deferral of settled derivative instruments	2	6
Other non-cash income and expenses, net	11	9
Changes in working capital:		
Decrease in accounts receivable and unbilled revenues	32	55
Increase in inventories	(19)	(20)
(Increase) decrease in margin deposits, net	(17)	7
Decrease in accounts payable and accrued liabilities	(22)	(29)
Other working capital items, net	7	6
Cash received to be returned to customers pursuant to the Residential Exchange Program	—	14
Other, net	(14)	(9)
Net cash provided by operating activities	**248**	**302**
Cash flows from investing activities:		
Capital expenditures	(313)	(501)
Distribution from Nuclear decommissioning trust	50	—
Sales tax refund received related to Tucannon River Wind Farm	23	—
Sales of Nuclear decommissioning trust securities	7	9
Purchases of Nuclear decommissioning trust securities	(7)	(10)
Proceeds from sale of property	—	4
Other, net	2	4
Net cash used in investing activities	**(238)**	**(494)**

See accompanying notes to condensed consolidated financial statements.

	2015	2014
Cash flows from financing activities:		
Proceeds from issuance of common stock, net of issuance costs	$ 271	$ —
Proceeds from issuance of long-term debt	145	225
Payments on long-term debt	(387)	—
Dividends paid	(44)	(43)
Net cash (used in) provided by financing activities	**(15)**	**182**
Decrease in cash and cash equivalents	(5)	(10)
Cash and cash equivalents, beginning of period	127	107
Cash and cash equivalents, end of period	**$ 122**	**$ 97**
Supplemental cash flow information is as follows:		
Cash paid for interest, net of amounts capitalized	$ 56	$ 45
Cash paid for income taxes	1	11
Non-cash investing and financing activities:		
Accrued capital additions	58	105
Accrued dividends payable	27	23

See accompanying notes to condensed consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS, continued
(In millions)
(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, 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. PGE's corporate headquarters are located in Portland, Oregon and its approximately 4,000 square mile, state-approved service area allocation is located entirely within the state of Oregon, encompassing 52 incorporated cities, of which Portland and Salem are the largest. As of June 30, 2015, PGE served 848,600 retail customers with a service area population of approximately 1.8 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 with the 2015 presentation, PGE has separately presented Increase in inventories of $20 million from Other working capital items, net and collapsed Decoupling mechanism deferrals, net of amortization of $3 million into Other non-cash income and expenses, net in the operating activities section of the condensed consolidated statement of cash flows for the six months ended June 30, 2014.

The financial information included herein for the three and six month periods ended June 30, 2015 and 2014 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 statements of income and comprehensive income, and condensed consolidated cash flows of the Company for these interim periods. 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. The financial information as of December 31, 2014 is derived from the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2014, included in Item 8 of PGE's Annual Report on Form 10-K, filed with the SEC on February 13, 2015, which should be read in conjunction with such condensed consolidated financial statements.

Comprehensive Income

PGE had no material components of other comprehensive income to report for the three and six month periods ended June 30, 2015 and 2014.

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.

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 or as a cumulative-effect adjustment as of the date of adoption, which was originally January 1, 2017 for the Company. In June 2015, the Financial Accounting Standards Board (FASB) voted to defer the effective date by one year, with early adoption permitted as of the original effective date. The final ASU reflecting these changes is expected to be issued later this year. 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 2014-09.

In April 2015, the FASB issued ASU 2015-03, *Interest—Imputation of Interest (Subtopic 835-30)* (ASU 2015-03), which requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The provisions of ASU 2015-03 are effective for fiscal years beginning after December 15, 2015, or January 1, 2016 for PGE, and interim periods within those fiscal years. Early adoption is permitted for financial statements that have not been previously issued. The provisions should be applied on a retrospective basis. Upon transition, an entity is required to comply with the applicable disclosures for a change in an accounting principle, which includes: i) the nature of and reason for the change in accounting principle; ii) the transition method; iii) a description of the prior-period information that has been retrospectively adjusted; and iv) the effect of the change on the financial statement line items. The adoption of the provisions of ASU 2015-03 is not expected to have a material impact on PGE's consolidated financial position, consolidated results of operation, or consolidated cash flows.

In May 2015, the FASB issued ASU 2015-07, *Fair Value Measurement (Topic 820), Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)* (ASU 2015-07), which removes the requirement to categorize within the fair value hierarchy investments for which fair value is measured using the net asset value per share practical expedient. The amendments also remove the requirement to make certain disclosures for all investments that are eligible to be measured at fair value using the net asset value per share practical expedient. Instead, such disclosures are restricted only to investments that the entity has decided to measure using the practical expedient. This standard is effective for interim and annual periods beginning after December 15, 2015. PGE will adopt the amendments contained in ASU 2015-07 on January 1, 2016, which is not expected to have an impact on the Company's consolidated financial position, consolidated results of operations, or consolidated cash flows.

In July 2015, the FASB issued ASU 2015-11, *Inventory (Topic 330), Simplifying the Measurement of Inventory* (ASU 2015-11), which changes the measurement principle for inventory from the *lower of cost or market* to *lower of cost and net realizable value*. Net realizable value is defined as the "estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation." ASU 2015-11 eliminates the guidance that entities consider replacement cost or net realizable value less an approximately normal profit margin in the subsequent measurement of inventory when cost is determined on a first-in, first-out or average cost basis. The provisions of ASU 2015-11 are effective for public entities with fiscal years beginning after December 15, 2016, or January 1, 2017 for PGE, and interim periods within those fiscal years. 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 2015-11.

NOTE 2: BALANCE SHEET COMPONENTS

Accounts Receivable, Net

Accounts receivable is net of an allowance for uncollectible accounts of $6 million as of June 30, 2015 and December 31, 2014.

The activity in the allowance for uncollectible accounts is as follows (in millions):

	Six Months Ended June 30,	
	2015	2014
Balance as of beginning of period	$ 6	$ 6
Provision, net	3	4
Amounts written off, less recoveries	(3)	(3)
Balance as of end of period	$ 6	$ 7

Inventories

PGE’s inventories, which are recorded at average cost, consist primarily of materials and supplies for use in operations, maintenance, and capital activities and fuel for use in generating plants. Fuel inventories include natural gas, coal, and oil. Periodically, the Company assesses the realizability of inventory for purposes of determining that inventory is recorded at the lower of average cost or market. During the six months ended June 30, 2015, the Company’s inventory balance increased largely as a result of contractual deliveries of coal exceeding usage due to plant maintenance and economic dispatch decisions.

Other Current Assets

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

	June 30, 2015	December 31, 2014
Prepaid expenses	$ 32	$ 39
Current deferred income tax asset	33	33
Margin deposits	28	11
Accrued sales tax refund related to Tucannon River Wind Farm	—	23
Assets from price risk management activities	3	6
Other	1	3
Other current assets	$ 97	$ 115

Electric Utility Plant, Net

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

	June 30, 2015	December 31, 2014
Electric utility plant	$ 8,301	$ 8,161
Construction work-in-progress	557	417
Total cost	8,858	8,578
Less: accumulated depreciation and amortization	(2,984)	(2,899)
Electric utility plant, net	$ 5,874	$ 5,679

Accumulated depreciation and amortization in the table above includes accumulated amortization related to intangible assets of $209 million and $191 million as of June 30, 2015 and December 31, 2014, respectively. Amortization expense related to intangible assets was $9 million and $6 million for the three months ended June 30, 2015 and 2014, respectively, and $18 million and $12 million for the six months ended June 30, 2015 and 2014, respectively. The Company's intangible assets primarily consist of computer software development and hydro licensing costs.

Regulatory Assets and Liabilities

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

	June 30, 2015		December 31, 2014	
	Current	Noncurrent	Current	Noncurrent
Regulatory assets:				
Price risk management	$ 98	$ 186	$ 100	$ 121
Pension and other postretirement plans	—	237	—	247
Deferred income taxes	—	87	—	86
Debt issuance costs	—	17	—	15
Deferred capital projects	10	—	19	—
Other	9	25	14	25
Total regulatory assets	$ 117	$ 552	$ 133	$ 494
Regulatory liabilities:				
Asset retirement removal costs	$ —	$ 824	$ —	$ 804
Trojan decommissioning activities	21	24	23	34
Asset retirement obligations	—	42	—	39
Other	32	33	37	29
Total regulatory liabilities	$ 53 *	$ 923	$ 60 *	$ 906

* 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):

	June 30, 2015	December 31, 2014
Regulatory liabilities—current	$ 53	$ 60
Accrued employee compensation and benefits	43	51
Accrued interest payable	25	26
Accrued dividends payable	27	23
Accrued taxes payable	21	22
Other	59	54
Total accrued expenses and other current liabilities	$ 228	$ 236

Asset Retirement Obligations

Asset retirement obligations (AROs) consist of the following (in millions):

	June 30, 2015	December 31, 2014
Trojan decommissioning activities	$ 43	$ 41
Utility plant	81	64
Non-utility property	11	11
Asset retirement obligations	$ 135	$ 116

Utility plant represents AROs that have been recognized for the Company’s thermal and wind generation sites and distribution and transmission assets where disposal is governed by environmental regulation.

The United States Environmental Protection Agency (EPA) published a final rule, effective October 19, 2015, that regulates Coal Combustion Residuals (CCRs) under the Resource Conservation and Recovery Act, Subtitle D. The new rule imposes extensive new requirements, including location restrictions, design and operating standards, groundwater monitoring and corrective action requirements, and closure and post-closure care requirements on CCR impoundments and landfills that are located on active power plants and not closed. The rule’s requirements for covered CCR impoundments and landfills include commencement or completion of closure activities generally between three and ten years from certain triggering events.

Based on a preliminary evaluation, the Company believes the rule will not have a material effect on operations at Boardman, which produce dry CCRs. Disposal of the dry CCRs occurs at an on-site landfill that is currently permitted and regulated by the State of Oregon under requirements similar to the new CCR rule.

Colstrip utilizes wet scrubbers and a number of settlement ponds that will require upgrading or closure to meet the new regulatory requirements. The operator of Colstrip has provided an initial cost estimate related to the impacts of the new CCR rule. As a result, during the second quarter of 2015, the Company recorded an increase to the existing Colstrip AROs in the amount of $15 million, with a corresponding increase in the cost basis of the plant, included in Electric utility plant, net on the consolidated balance sheet. PGE plans to seek recovery in customer prices of the incremental costs associated with the new rule.

Credit Facilities

During the first quarter of 2015, PGE determined that a $500 million aggregate revolving credit facility capacity would be sufficient to meet its liquidity needs and accordingly, in March 2015, reduced its aggregate revolving credit capacity from $700 million to $500 million. As of June 30, 2015, PGE has a $500 million revolving credit facility, which is scheduled to expire in November 2019.

Pursuant to the terms of the agreement, the revolving credit facility may be used for general corporate purposes and as backup for commercial paper borrowings, and also 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. The revolving credit facility contains provisions for two, one-year extensions subject to approval by the banks, 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 June 30, 2015, PGE was in compliance with this covenant with a 50.4% debt-to-total capital ratio.

PGE classifies any borrowings under the revolving credit facility and outstanding commercial paper as Short-term debt on the condensed consolidated balance sheets. As of June 30, 2015, PGE had no borrowings or commercial paper outstanding, $38 million of letters of credit issued, and an aggregate available capacity under the credit facility of $462 million.

In addition, PGE has two $30 million letter of credit facilities, under which the Company can request letters of credit for original terms not to exceed one year. The issuance of such letters of credit is subject to the approval of the issuing institution. As of June 30, 2015, $59 million of letters of credit had been issued under these facilities.

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.

Pursuant to an order issued by the Federal Energy Regulatory Commission (FERC), the Company is authorized to issue short-term debt up to $900 million through February 6, 2016. The authorization provides that if utility assets financed by unsecured debt are divested, then a proportionate share of the unsecured debt must also be divested.

Long-term Debt

During the six months ended June 30, 2015, PGE had the following long-term debt transactions:

- In June, repaid $200 million of long-term bank loans;
- In May, issued $70 million of 3.50% Series First Mortgage Bonds (FMBs) due 2035 and repaid $67 million of 6.80% Series FMBs, due January 2016;
- In February, repaid $50 million of long-term bank loans; and
- In January, issued $75 million of 3.55% Series FMBs due 2030 and repaid $70 million of 3.46% Series FMBs.

On July 10, 2015, the Company repaid the remaining outstanding balance of long-term bank loans in the amount of $55 million.

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

Pension and Other Postretirement Benefits

Components of net periodic benefit cost are as follows (in millions):

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2015	2014	2015	2014	2015	2014
Three Months Ended June 30:						
Service cost	$ 5	$ 3	$ 1	$ 1	$ —	$ —
Interest cost	8	8	1	1	1	1
Expected return on plan assets	(10)	(10)	(1)	(1)	—	—
Amortization of prior service cost	—	—	—	1	—	—
Amortization of net actuarial loss	5	5	—	—	—	—
Net periodic benefit cost	$ 8	$ 6	$ 1	$ 2	$ 1	$ 1
Six Months Ended June 30:						
Service cost	$ 9	$ 7	$ 2	$ 1	$ —	$ —
Interest cost	16	17	2	2	1	1
Expected return on plan assets	(20)	(20)	(1)	(1)	—	—
Amortization of prior service cost	—	—	—	1	—	—
Amortization of net actuarial loss	10	9	—	—	—	—
Net periodic benefit cost	$ 15	$ 13	$ 3	$ 3	$ 1	$ 1

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 June 30, 2015 and December 31, 2014, and then classifies these financial assets and liabilities based on a fair value hierarchy. The fair value hierarchy is used to prioritize the inputs to the valuation techniques used to measure fair value. These three levels 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 reporting date.

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

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 six month periods ended June 30, 2015 and 2014, except those transfers from Level 3 to Level 2 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 June 30, 2015			
	Level 1	Level 2	Level 3	Total
Assets:				
Nuclear decommissioning trust: (1)				
Money market funds	$ —	$ 16	$ —	$ 16
Debt securities:				
Domestic government	4	9	—	13
Corporate credit	—	11	—	11
Non-qualified benefit plan trust: (2)				
Equity securities—domestic	5	2	—	7
Debt securities—domestic government	1	—	—	1
Assets from price risk management activities: (1) (3)				
Electricity	—	3	1	4
Natural gas	—	—	—	—
	$ 10	$ 41	$ 1	$ 52
Liabilities—Liabilities from price risk management activities: (1) (3)				
Electricity	$ —	$ 20	$ 132	$ 152
Natural gas	—	99	37	136
	$ —	$ 119	$ 169	$ 288

(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) Excludes insurance policies of $27 million, which are recorded at cash surrender value.
(3) For further information, see Note 4, Price Risk Management.

	As of December 31, 2014			
	Level 1	Level 2	Level 3	Total
Assets:				
Nuclear decommissioning trust: [1]				
Money market funds	$ —	$ 65	$ —	$ 65
Debt securities:				
Domestic government	7	7	—	14
Corporate credit	—	11	—	11
Non-qualified benefit plan trust: [2]				
Equity securities:				
Domestic	4	1	—	5
International	1	—	—	1
Assets from price risk management activities: [1] [3]				
Electricity	—	4	1	5
Natural gas	—	2	—	2
	$ 12	$ 90	$ 1	$ 103
Liabilities—Liabilities from price risk management activities: [1] [3]				
Electricity	$ —	$ 32	$ 80	$ 112
Natural gas	—	95	21	116
	$ —	$ 127	$ 101	$ 228

(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) Excludes insurance policies of $26 million, which are recorded at cash surrender value.
(3) For further information, see Note 4, Price Risk Management.

Trust assets held in the Nuclear decommissioning and Non-qualified benefit 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:

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. Money market funds are classified as Level 2 in the fair value hierarchy as the securities are traded in active markets of similar securities but are not directly valued using quoted market prices.

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 reporting 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 yield 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 primarily 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 reporting date. Principal markets for equity prices include published exchanges such as NASDAQ and the New York Stock Exchange. Certain mutual fund assets included in commingled trusts or separately managed accounts are classified as Level 2 in the fair value hierarchy as pricing inputs are directly or indirectly observable in the marketplace.

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.

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		Valuation Technique	Significant Unobservable Input	Price per Unit		
	Assets	Liabilities			Low	High	Weighted Average
	(in millions)						
As of June 30, 2015:							
Electricity physical forward	$ —	$ 131	Discounted cash flow	Electricity forward price (per MWh)	$ 12.97	$ 66.27	$ 31.43
Natural gas financial swaps	—	37	Discounted cash flow	Natural gas forward price (per Decatherm)	2.40	4.33	2.90
Electricity financial futures	1	1	Discounted cash flow	Electricity forward price (per MWh)	21.35	37.90	30.56
	$ 1	$ 169					
As of December 31, 2014:							
Electricity physical forward	$ —	$ 77	Discounted cash flow	Electricity forward price (per MWh)	$ 11.97	$ 122.72	$ 37.43
Natural gas financial swaps	—	21	Discounted cash flow	Natural gas forward price (per Decatherm)	2.88	4.86	3.41
Electricity financial futures	1	3	Discounted cash flow	Electricity forward price (per MWh)	11.97	39.26	27.88
	$ 1	$ 101					

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, the Company employs the mid-point of the market’s bid-ask spread 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 aggregated 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 monthly basis by the Company. This process includes analytical review of changes in commodity prices as well as procedures to analyze and identify the reasons for the changes over specific reporting periods.

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 the Company’s position as either the buyer or seller of 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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Balance as of the beginning of the period	$ 148	$ 131	$ 100	$ 139
Net realized and unrealized losses (gains)*	20	(44)	70	(55)
Transfers out of Level 3 to Level 2	—	2	(2)	5
Balance as of the end of the period	$ 168	$ 89	$ 168	$ 89

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

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 six months ended June 30, 2015 and 2014, 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 financial 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 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 is classified as Level 3 and is estimated based on the terms of the loans and the Company’s creditworthiness. These significant unobservable inputs to the Level 3 fair value measurement include the interest rate and the length of the loan. The estimated fair value of the Company’s unsecured term bank loans approximates their carrying value.

As of June 30, 2015, the carrying amount of PGE’s long-term debt was $2,259 million and its estimated aggregate fair value was $2,568 million, consisting of $2,513 million and $55 million classified as Level 2 and Level 3, respectively, in the fair value hierarchy. As of December 31, 2014, the carrying amount of PGE’s long-term debt was $2,501 million and its estimated aggregate fair value was $2,901 million, consisting of $2,596 million and $305 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 and manage risk. Such activities include fuel and power purchases and sales resulting from economic dispatch decisions for Company-owned generation. As a result, 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 exchange rate risk in order to reduce volatility in NVPC for its retail customers. These derivative instruments may include forwards, futures, swaps, and option contracts for electricity, natural gas, oil, and foreign currency, which are recorded at fair value on the condensed consolidated balance sheets, 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 OPUC, PGE 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):

	June 30, 2015	December 31, 2014
Current assets:		
Commodity contracts:		
Electricity	$ 3	$ 4
Natural gas	—	2
Total current derivative assets	3 (1)	6 (1)
Noncurrent assets:		
Commodity contracts:		
Electricity	1	1
Total noncurrent derivative assets	1 (2)	1 (2)
Total derivative assets not designated as hedging instruments	$ 4	$ 7
Total derivative assets	$ 4	$ 7
Current liabilities:		
Commodity contracts:		
Electricity	$ 38	$ 54
Natural gas	63	52
Total current derivative liabilities	101	106
Noncurrent liabilities:		
Commodity contracts:		
Electricity	114	58
Natural gas	73	64
Total noncurrent derivative liabilities	187	122
Total derivative liabilities not designated as hedging instruments	$ 288	$ 228
Total derivative liabilities	$ 288	$ 228

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

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

PGE's net 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):

	June 30, 2015		December 31, 2014	
Commodity contracts:				
Electricity	12	MWh	16	MWh
Natural gas	129	Decatherms	127	Decatherms
Foreign currency	$ 7	Canadian	$ 7	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 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, which are excluded from the offsetting table presented below.

Information related to Price risk management liabilities subject to master netting agreements is as follows (in millions):

	Gross Amounts Recognized	Gross Amounts Offset	Net Amounts Presented	Gross Amounts Not Offset in Condensed Consolidated Balance Sheets		Net Amount
				Derivatives	Cash Collateral(1)	
As of June 30, 2015:						
Liabilities:						
Commodity contracts:						
Electricity(2)	$ 117	$ —	$ 117	$ (117)	$ —	$ —
Natural gas(2)	13	—	13	(13)	—	—
	$ 130	$ —	$ 130	$ (130)	$ —	$ —
As of December 31, 2014:						
Liabilities:						
Commodity contracts:						
Electricity(2)	$ 55	$ —	$ 55	$ (55)	$ —	$ —
Natural gas(2)	17	—	17	(17)	—	—
	$ 72	$ —	$ 72	$ (72)	$ —	$ —

(1) As of June 30, 2015 and December 31, 2014, PGE had posted collateral in the amount of $13 million and $11 million, respectively, which consisted entirely of letters of credit.
(2) Included in Liabilities from price risk management activities—current and Liabilities from price risk management activities—noncurrent.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Commodity contracts:				
Electricity	$ 29	$ (38)	$ 70	$ (29)
Natural Gas	—	(6)	44	(42)

Net unrealized and certain net realized losses (gains) presented in the preceding table are offset within the condensed consolidated statements of income by the effects of regulatory accounting. Of the net losses (gains) recognized in Net income for the three month periods ended June 30, 2015 and 2014, net losses of $33 million and $52 million, respectively, have been offset. Net losses of $116 million and $64 million have been offset for the six month periods ended June 30, 2015 and 2014, 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 June 30, 2015 related to PGE's derivative activities would become realized as a result of the settlement of the underlying derivative instrument (in millions):

	2015	2016	2017	2018	2019	Thereafter	Total
Commodity contracts:							
Electricity	$ 22	$ 19	$ 7	$ 6	$ 6	$ 88	$ 148
Natural gas	37	61	31	6	1	—	136
Net unrealized loss	$ 59	$ 80	$ 38	$ 12	$ 7	$ 88	$ 284

PGE's secured and unsecured debt is currently rated at investment grade by Moody's Investors Service (Moody's) and Standard and Poor's Ratings Services (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 June 30, 2015 was $274 million, for which PGE has posted $56 million in collateral, consisting of $44 million in letters of credit and $12 million in cash. If the credit-risk-related contingent features underlying these agreements were triggered at June 30, 2015, the cash requirement to either post as collateral or settle the instruments immediately would have been $261 million. As of June 30, 2015, PGE had posted a nominal amount of cash collateral for derivative instruments with no credit-risk related contingent features. 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:

	June 30, 2015	December 31, 2014
Assets from price risk management activities:		
Counterparty A	66%	63%
Counterparty B	3	14
	69%	77%
Liabilities from price risk management activities:		
Counterparty C	40%	22%
Counterparty D	5	12
	45%	34%

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 is computed based on the weighted average number of common shares outstanding during the period. Diluted earnings per share is 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; ii) unvested time-based and performance-based restricted stock units, along with related dividend equivalent rights; and iii) shares issuable pursuant to an equity forward sale agreement (EFSA). See Note 6, Equity, for additional information on the EFSA and its impact on earnings per share. 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 six month periods ended June 30, 2015, unvested performance-based restricted stock units and related dividend equivalent rights of approximately 306,000 were excluded from the dilutive calculation because the performance goals had not been met, with 365,000 excluded for the three and six month periods ended June 30, 2014.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	**2014**	**2015**	**2014**
Weighted-average common shares outstanding—basic	80,745	78,183	79,515	78,154
Dilutive effect of potential common shares	—	1,868	—	1,588
Weighted-average common shares outstanding—diluted	80,745	80,051	79,515	79,742

NOTE 6: EQUITY

The activity in equity during the six months ended June 30, 2015 and 2014 is as follows (dollars in millions):

	Common Stock		Accumulated Other Comprehensive Loss	Retained Earnings	Total
	Shares	Amount			
Balances as of December 31, 2014	78,228,339	$ 918	$ (7)	$ 1,000	$ 1,911
Issuance of common stock, net of issuance costs of $12	10,400,000	271	—	—	271
Issuances of shares pursuant to equity-based plans	137,290	1	—	—	1
Stock-based compensation	—	1	—	—	1
Dividends declared	—	—	—	(48)	(48)
Net income	—	—	—	85	85
Balances as of June 30, 2015	88,765,629	$ 1,191	$ (7)	$ 1,037	$ 2,221
Balances as of December 31, 2013	78,085,559	$ 911	$ (5)	$ 913	$ 1,819
Issuances of shares pursuant to equity-based plans	116,682	—	—	—	—
Stock-based compensation	—	3	—	—	3
Dividends declared	—	—	—	(44)	(44)
Net income	—	—	—	93	93
Balances as of June 30, 2014	78,202,241	$ 914	$ (5)	$ 962	$ 1,871

During the second quarter of 2015, PGE physically settled in full the EFSA, with the issuance of 10,400,000 shares of common stock in exchange for net proceeds of $271 million. Prior to settlement, the potentially issuable shares pursuant to the EFSA were reflected in PGE's diluted earnings per share calculations using the treasury stock method. Under this method, the number of shares of PGE's common stock used in calculating diluted earnings per share for a reporting period are increased by the number of shares, if any, that would be issued upon physical settlement of the EFSA less the number of shares that could be purchased by PGE in the market with the proceeds received from issuance (based on the average market price during that reporting period).

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 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 reasonably estimated, 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) there are significant facts in dispute; vi) there are a large number of parties (including where it is uncertain how liability, if any, will be shared among multiple defendants); or vii) there are a wide range of potential outcomes. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution, including any possible loss, fine, penalty, or business impact.

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

In 2003, in two separate legal proceedings, lawsuits were filed in Marion County 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 issued a ruling ordering the abatement of the class action proceedings. The Oregon Supreme Court concluded that the OPUC had primary jurisdiction to determine what, if any, remedy could be offered to PGE customers, through price reductions or refunds, for any amount of return on the Trojan investment that the Company collected in prices.

The Oregon Supreme Court further stated that if the OPUC determined that it can provide a remedy to PGE’s customers, then the class action proceedings may become moot in whole or in part. The Oregon Supreme Court added that, if the OPUC determined that it cannot provide a remedy, the court system may have a role to play. The Oregon Supreme Court also ruled that the plaintiffs retain the right to return to the Marion County Circuit Court for disposition of whatever issues remain unresolved from the remanded OPUC proceedings. In October 2006, the Marion County Circuit Court abated the class actions in response to the ruling of the Oregon Supreme Court.

In June 2015, based on a motion filed by PGE, the Marion County Circuit Court lifted the abatement and set oral argument on the Company's motion for Summary Judgment to occur on July 27, 2015.

PGE believes that the October 2, 2014 Oregon Supreme Court decision has 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 pending, management believes that it is reasonably possible that such a loss to the Company 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.

Pacific Northwest Refund Proceeding

In response to the Western energy crisis of 2000-2001, the FERC initiated, beginning in 2001, a series of adjudicatory and investigative proceedings to determine whether refunds are warranted for bilateral sales of electricity in the Pacific Northwest wholesale spot market during the period December 25, 2000 through June 20, 2001. In an order issued in 2003, the FERC denied refunds. Various parties appealed the order to the Ninth Circuit Court of Appeals and, on appeal, the Court remanded the issue of refunds to the FERC for further consideration.

On remand, in 2011 and thereafter, the FERC issued several procedural orders that established an evidentiary hearing, defined the scope of the hearing, expanded the refund period to include January 1, 2000 through December 24, 2000 for certain types of claims, and described the burden of proof that must be met to justify abrogation of the contracts at issue and the imposition of refunds. Those orders included a finding by the FERC that the *Mobile-Sierra* public interest standard governs challenges to the bilateral contracts at issue in this proceeding, and the strong presumption under *Mobile-Sierra* that the rates charged under each contract are just and reasonable would have to be specifically overcome either by: i) a showing that a respondent had violated a contract or tariff and that the violation had a direct connection to the rate charged under the applicable contract; or ii) a showing that the contract rate at issue imposed an excessive burden or seriously harmed the public interest. The FERC also held that a market-wide remedy was not appropriate, given the bilateral contract nature of the Pacific Northwest spot markets. Refund proponents have filed petitions for appeal of these procedural orders with the Ninth Circuit. Those appeals remain pending.

In response to the evidence and arguments presented during the hearing, in May 2015, the FERC issued an order upholding the decision of an Administrative Law Judge that the refund proponents had failed to meet the *Mobile-Sierra* burden with respect to all but one respondent. That order is subject to requests for rehearing.

The Company has settled all of the direct claims asserted against it in the proceedings for an immaterial amount. The settlements and associated FERC orders have not fully eliminated the potential for so-called "ripple claims," which have been described by the FERC as "sequential claims against a succession of sellers in a chain of purchases that are triggered if the last wholesale purchaser in the chain is entitled to a refund." However, the FERC has acknowledged that the potential for such ripple claims is "speculative" and the Company believes that ripple claims made against it, if any, are unlikely to be successful under the FERC orders currently in effect. Accordingly, unless those FERC orders are overturned or modified, the Company does not believe that it will incur any material loss in connection with this matter.

Management cannot predict the outcome of the various pending appeals and remands concerning this matter. If, on rehearing, appeal, or subsequent remand, the Ninth Circuit or the FERC were to reverse previous FERC rulings and find that the *Mobile-Sierra* standard is not applicable or that a market-wide remedy is appropriate, it is possible that additional refund claims could be asserted against the Company. However, management cannot predict, under such circumstances, which contracts would be subject to refunds, the basis on which refunds would be ordered, or how such refunds, if any, would be calculated. Further, management cannot predict whether any current respondents, if ordered to make refunds, would pursue additional refund claims against their suppliers, and, if so, what the basis or amounts of such potential refund claims against the Company would be. Due to these uncertainties, sufficient information is currently not available to determine PGE's liability, if any, or to estimate a range of reasonably possible loss.

EPA Investigation of Portland Harbor

In 1997, an investigation by the 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 (CERCLA) 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 one hundred.

The Portland Harbor site continues to undergo a remedial investigation (RI) and feasibility study (FS) pursuant to an Administrative Order on Consent (AOC) between the EPA and several PRPs known as the Lower Willamette Group (LWG), which does not include PGE.

In 2012, the LWG submitted a draft FS to the EPA for review and approval. The draft FS, which is being rewritten by the EPA, along with the RI, will provide the framework for the EPA to determine a clean-up remedy for Portland Harbor that will be documented in a Record of Decision, which the EPA is not expected to issue before 2017.

The draft FS evaluates several alternative clean-up approaches, which would take from two to 28 years with costs ranging from $169 million to $1.8 billion, depending on the selected remedial action levels and the choice of remedy. The draft FS does not address responsibility for the costs of clean-up, allocate such costs among PRPs, or define precise boundaries for the clean-up. Responsibility for funding and implementing the EPA's selected clean-up will be determined after the issuance of the Record of Decision.

Management believes that it is reasonably possible that this matter could result in a loss to the Company. However, due to the uncertainties discussed above, sufficient information is currently not available to determine PGE's liability for the cost of any required investigation or remediation of the Portland Harbor site or to estimate a range of potential loss.

DEQ Investigation of Downtown Reach

The Oregon Department of Environmental Quality (DEQ) has executed a memorandum of understanding with the EPA to administer and enforce clean-up activities for portions of the Willamette River that are upriver from the Portland Harbor Superfund site (the Downtown Reach). In 2010, the DEQ issued an order requiring PGE to perform an investigation of certain portions of the Downtown Reach. PGE completed this investigation in 2011 and entered into a consent order with the DEQ in 2012 to conduct a feasibility study of alternatives for remedial action for the portions of the Downtown Reach that were included within the scope of PGE's investigation.

Following the DEQ's evaluation of a draft feasibility study, PGE submitted a final feasibility study report to the DEQ in September 2014, which described possible remediation alternatives that ranged in estimated cost from $3 million to $8 million. Based on the estimated cost of the alternative recommended by the Company in the feasibility study report, PGE recorded a $3 million reserve for this matter in 2014 and established a regulatory asset of $3 million for future recovery in prices. In April 2015, the DEQ issued its Record of Decision in which it selected the remedy recommended in the feasibility study report.

The final order issued by the OPUC in the 2015 General Rate Case (GRC) included revenues to offset the amortization of the regulatory asset over a two year period that began January 1, 2015. As of June 30, 2015, the Company has a regulatory asset of $2 million remaining for future recovery of costs related to the Downtown Reach. The 2016 GRC filing provides for the possibility of revising the recovery if costs vary from what was estimated.

Alleged Violation of Environmental Regulations at Colstrip

In July 2012, PGE received a Notice of Intent to Sue (Notice) for violations of the Clean Air Act (CAA) at Colstrip Steam Electric Station (CSES) from counsel on behalf of the Sierra Club and the Montana Environmental Information Center (MEIC). The Notice was also addressed to the other CSES co-owners, including PPL Montana, LLC, the operator of CSES. PGE has a 20% ownership interest in Units 3 and 4 of CSES. The Notice alleged certain violations of the CAA, including New Source Review, Title V, and opacity requirements, and stated that the Sierra Club and MEIC would: i) request a United States District Court to impose injunctive relief and civil penalties; ii) require a beneficial environmental project in the areas affected by the alleged air pollution; and iii) seek reimbursement of Sierra Club's and MEIC's costs of litigation and attorney's fees.

The Sierra Club and MEIC asserted that the CSES owners violated the Title V air quality operating permit during portions of 2008 and 2009 and that the owners have violated the CAA by failing to timely submit a complete air quality operating permit application to the Montana Department of Environmental Quality (MDEQ). The Sierra Club and MEIC also asserted violations of opacity provisions of the CAA.

On March 6, 2013, the Sierra Club and MEIC sued the CSES co-owners, including PGE, for these and additional alleged violations of various environmental related regulations. The plaintiffs are seeking relief that includes an injunction preventing the co-owners from operating CSES except in accordance with the CAA, the Montana State Implementation Plan, and the plant's federally enforceable air quality permits. In addition, plaintiffs are seeking civil penalties against the co-owners including $32,500 per day for each violation occurring through January 12, 2009, and $37,500 per day for each violation occurring thereafter.

In May 2013, the defendants filed a motion to dismiss 36 of 39 claims alleged in the complaint. In September 2013, the plaintiffs filed a motion for partial summary judgment regarding the appropriate method of calculating emission increases. Also in September 2013, the plaintiffs filed an amended complaint that withdrew Title V and opacity claims, added claims associated with two 2011 projects, and expanded the scope of certain claims to encompass approximately 40 additional projects. In July 2014, the court denied both the defendants' motion to dismiss and the plaintiffs' motion for partial summary judgment.

On August 27, 2014, the plaintiffs filed a second amended complaint to which the defendants' response was filed on September 26, 2014. The second amended complaint continues to seek injunctive relief, declaratory relief, and civil penalties for alleged violations of the federal Clean Air Act. The plaintiffs state in the second amended complaint that it was filed, in part, to comply with the court's ruling on the defendants' motion to dismiss and plaintiffs' motion for partial summary judgment. Discovery in this matter is ongoing with trial now scheduled for November 2015.

Management believes that it is reasonably possible that this matter could result in a loss to the Company. However, due to the uncertainties concerning this matter, PGE cannot predict the outcome or determine whether it would have a material impact on the Company.

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, which 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 June 30, 2015, 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 expectations, beliefs and projections are expressed in good faith and are believed by the Company 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 PGE's expectations, beliefs, or projections 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 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 affecting PGE's power generating facilities, including forced outages, hydro and wind conditions, and disruptions of fuel supply, which may cause the Company to incur repair costs, as well as increase power costs for replacement power;
- 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, coal, and oil, 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 and proprietary information;
- employee workforce factors, including potential strikes, work stoppages, transitions in senior management, and the number of employees approaching retirement;
- new federal, state and local laws that could have adverse effects on operating results;
- political and economic conditions;
- 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. 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, 2014, and other periodic and current reports filed with the SEC.

Capital Requirements and Financing—Carty Generating Station (Carty) is a 440 MW natural gas-fired baseload resource under construction, which is located in Eastern Oregon adjacent to Boardman. This project is currently on budget at an estimated total cost of $450 million, excluding AFDC, and is expected to be online in the second quarter of 2016. As of June 30, 2015, $385 million, including $27 million of AFDC, is included in construction work-in-process for Carty. The Company filed for recovery of costs related to this project in the 2016 GRC.

In total, the Company's 2015 capital expenditures are expected to approximate $598 million, which includes an estimated $165 million related to Carty. For additional information regarding estimated capital expenditures, see *"Capital Requirements"* in the Liquidity and Capital Resources section of this Item 2.

PGE expects to fund 2015 estimated capital expenditures and repayments of long-term debt with a combination of cash from operations, which is expected to range from $455 million to $495 million, and proceeds from the issuances of equity and debt securities. For additional information, see *"Liquidity"* and *"Debt and Equity Financings"* in the Liquidity and Capital Resources section of this Item 2.

General Rate Cases—On January 1, 2015, new customer prices went into effect pursuant to the OPUC order issued on PGE's 2015 General Rate Case (2015 GRC), which was based on a 2015 test year and included forecasted retail energy deliveries assuming average weather conditions. The OPUC authorized a $15 million increase in annual revenues, representing an approximate 1% overall increase in customer prices. The increase included recovery of costs related to the Port Westward Unit 2 natural gas-fired flexible capacity generating plant (PW2) and Tucannon River Wind Farm (Tucannon River). In addition, the order approved a capital structure of 50% debt and 50% equity, a return on equity of 9.68%, a cost of capital of 7.56%, and an average rate base of approximately $3.8 billion.

Pursuant to the 2015 GRC order, a forecast of capital expenditures for PW2 of $323 million and Tucannon River of $525 million was used to set customers prices. However, to the extent that total actual capital expenditures are less than that used to set customer prices, the 2015 revenue requirement impact of any shortfall will be deferred for future refund to customers. In the event that total actual capital expenditures exceed those used to set customer prices, there is no deferral of such incremental capital costs. The Company expects to defer approximately $2 million in 2015 for the revenue requirement to be refunded to customers for the two generation resources, as forecast capital expenditures are expected to be less than the amounts used for setting prices.

On February 12, 2015, PGE filed with the OPUC a 2016 GRC, which is based on a 2016 test year and includes costs related to Carty. The Company's request, when combined with other supplemental tariff changes, would result in an increase in annual revenues of $66 million. Such change would result in an approximate 3.7% overall increase relative to currently approved prices. PGE proposed a capital structure of 50% debt and 50% equity, a return on equity of 9.9%, a cost of capital of 7.67%, and a rate base of approximately $4.5 billion.

In June 2015, a partial stipulation was filed covering agreements reached among PGE, OPUC Staff, and other parties on a variety of issues in the proceeding, including, with certain conditions, cost recovery of the Carty Generating Station. In addition, PGE has updated load forecasts and filed revised 2016 power cost estimates.

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

	As Filed February 12, 2015	Stipulations and Updates	As Revised July 15, 2015
Carty	$ 83	$ 2	$ 85
Base business cost	39	(21)	18
Supplemental tariff updates	(56) *	(6)	(62)
Annual revenue requirement, net	$ 66	$ (25)	$ 41

* Includes $26 million related to capital project deferrals expected to be fully recovered in 2015, $17 million of accelerated customer credits related to the settlement of a legal matter concerning costs associated with the operation of the Independent Spent Fuel Storage Installation at Trojan, a $15 million increase in customer credits related to the Residential Exchange Program, and other tariff updates.

On July 20, 2015, PGE notified the OPUC that the parties have reached a settlement in principle of all remaining revenue requirement matters in the 2016 GRC, with the exception of one power cost issue. The parties also proposed a schedule for resolving the remaining power cost issue. A stipulation reflecting the details of the settlement is expected to be filed with the OPUC within the next few weeks. Prior to the OPUC's final order, the Company will provide final updates to the load and power cost forecasts.

The above described stipulations with respect to the 2016 GRC are subject to OPUC approval. Regulatory review of the 2016 GRC will continue throughout 2015, with a final order expected to be issued by the OPUC by mid-December 2015. New customer prices are expected to become effective in 2016, with an initial price decrease January 1 and a price increase effective when Carty becomes operational, which is expected in the second quarter of 2016.

The general rate case filings, as well as copies of the orders, direct testimony, exhibits, and stipulations are available on the OPUC website at www.oregon.gov/puc.

Operating Activities—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. The Company generates revenues and cash flows primarily from the sale and distribution of electricity to customers in its service territory.

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 is a winter-peaking utility that typically experiences its highest retail energy sales during the winter heating season, although a slightly lower peak occurs in the summer that generally results from air conditioning demand. Price changes and customer usage patterns, which can be affected by the economy, also have an effect on revenues while the availability and price of purchased power, hydro and wind generation and fuel costs for thermal plants can affect income from operations.

Customers and Demand—The 0.8% increase in retail energy deliveries for the first half of 2015 compared with the first half of 2014 was driven by a 9.6% increase in industrial energy deliveries combined with a 1.3% increase in commercial deliveries, and largely offset by a 4.5% decrease in residential energy deliveries. Higher industrial energy deliveries were driven by increased demand from the high tech, paper, food, and transportation manufacturing sectors, while higher commercial energy deliveries were driven by warmer weather in June 2015.

The 4.5% overall decline in residential energy deliveries during the first half of 2015, as compared with the first half of 2014, was driven by the effects of warmer weather in 2015 discussed as follows:

- During the first quarter of 2015, warmer weather caused heating degree-days, an indication of the extent to which customers are likely to have used electricity for heating, to be 22% lower than the first quarter of 2014 and 21% below average. According to the National Oceanic and Atmospheric Administration's (NOAA's) climatological rankings, the 3-month period of January through March 2015 was the warmest on record for the State of Oregon. As a result, residential energy deliveries for the first quarter of 2015 were 11.2% lower than the first quarter of 2014.

- During the second quarter of 2015, warmer weather, particularly in June, caused cooling degree-days, an indication of the extent to which customers are likely to have used electricity for cooling, to be 263% higher than the second quarter of 2014 and 196% above average. According to NOAA's climatological rankings, the 3-month period of April through June 2015 was the third warmest on record for the State of Oregon, with June 2015 the warmest June on record. As a result, residential energy deliveries for the second quarter of 2015 were 4.9% higher than the second quarter of 2014.

Energy efficiency and conservation efforts by retail customers continue to influence total energy deliveries, although the financial impacts to the Company of such efforts are largely mitigated by the decoupling mechanism.

The following table presents the average number of retail customers by customer class, and corresponding energy deliveries, for the periods indicated and includes customers purchasing their energy from Electricity Service Suppliers (ESSs):

	Six Months Ended June 30,				
	2015		2014		
	Average Number of Customers	Retail Energy Deliveries*	Average Number of Customers	Retail Energy Deliveries*	% Increase (Decrease)in Energy Deliveries
Residential	740,188	3,559	734,218	3,726	(4.5)%
Commercial	105,082	3,640	104,674	3,595	1.3 %
Industrial	262	2,255	260	2,058	9.6 %
Total	845,532	9,454	839,152	9,379	0.8 %

* In thousands of MWh.

Power Operations—To meet the energy needs of its retail customers, the Company utilizes a combination of its own generating resources and wholesale market transactions. Based on numerous factors, including plant availability, customer demand, river flows, wind conditions, and current wholesale prices, PGE makes economic dispatch decisions continuously in an effort to obtain reasonably-priced power for its retail customers. In addition, PGE's thermal generating plants require varying levels of annual maintenance, during which the respective plant is unavailable to provide power. As a result, the amount of power generated and purchased in the wholesale market to meet the Company's retail load requirement can vary from period to period. Plant availability approximated 90% and 89% during the first half of 2015 and 2014, respectively, for those plants PGE operates. Plant availability of Colstrip Units 3 and 4, of which the Company has a 20% ownership interest and does not operate, approximated 93% and 87% during the first half of 2015 and 2014, respectively.

During the first half of 2015, the Company's generating plants provided approximately 49% of its retail load requirement compared with 46% in the first half of 2014. The increase in the proportion of power generated to meet the Company's retail load requirement was largely the result of a lower amount of thermal generation being economically displaced by lower-cost purchased power during the first half of 2015 relative to the first half of 2014.

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. Energy received from these hydro resources fell below projected levels included in the PGE's AUT by 6% for the first half of 2015 and exceeded projected levels by 2% for the first half of 2014, and provided 19% and 20% of the Company's retail load requirement for first half of 2015 and 2014, respectively. Energy from hydro resources is expected to be below projected levels included in the AUT for 2015.

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. Energy received from wind generating resources fell short of that projected in PGE's AUT by 27% for the first half of 2015 and 5% for the first half of 2014, and provided approximately 9% and 7% of the Company's retail load requirement during the first half of 2015 and 2014, respectively.

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. To the extent actual NVPC, subject to certain adjustments, is above or below the deadband, the PCAM provides for 90% of the variance to be collected from or refunded to customers, respectively, subject to a regulated earnings test. Pursuant to the regulated earnings test, a refund will occur only to the extent that it results in PGE's actual regulated return on equity (ROE) for that year being no less than 1% above the Company's latest authorized ROE, while a collection will occur only to the extent that it results in PGE's actual regulated ROE for that year being no greater than 1% below the Company's authorized ROE. Any estimated refund to customers pursuant to the PCAM is recorded as a reduction in Revenues 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. The deadband range is from $15 million below to $30 million above baseline NVPC.

For the first half of 2015, actual NVPC was approximately $2 million below baseline NVPC. Based on forecast data, NVPC for the year ending December 31, 2015 is currently estimated to be below baseline NVPC, but within the deadband range. Accordingly, no estimated collection from, or refund to, customers is expected under the PCAM for 2015.

For the first half of 2014, actual NVPC was approximately $14 million below baseline NVPC. For the year ended December 31, 2014, actual NVPC was $7 million below baseline NVPC, which is within the established deadband range. Accordingly, no estimated refund to customers was recorded pursuant to PCAM for 2014.

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:

- Claims for refunds related to wholesale energy sales during 2000 - 2001 in the Pacific Northwest Refund Proceeding; and
- An investigation of environmental matters regarding Portland Harbor.

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

In June 2014, the EPA released a proposed rule, which it calls the "Clean Power Plan." Under the proposed 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 proposed rule would establish state-specific goals in terms of pounds of carbon dioxide emitted per MWh of energy produced. The proposed rule is intended to result in a reduction of carbon emissions from existing power plants across all states to approximately 30% 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; iii) expanding use of zero- and low-carbon emitting generation (such as renewable energy and nuclear energy); and iv) implementing customer energy efficiency programs. The final goal would need to be met by 2030 and an interim goal for each state would need to be met on average over the 10-year period from 2020 to 2029. Under the proposed rule, states would have flexibility in designing programs to meet their emission reduction targets, including the four 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.

The EPA has indicated that it expects to issue the final rule in the summer of 2015. Under the proposed rule, states would have until June 30, 2016 to submit plans to implement the rule (subject to extension). PGE cannot predict whether the proposed rule will be adopted or, if adopted, how the states in which the Company's generation facilities are located will implement the rule or how the rule may impact the Company’s operations. The Company continues to monitor the developments around the proposed rule.

In December 2014, the EPA signed a final rule, which becomes effective October 19, 2015, that regulates Coal Combustion Residuals (CCRs) under the Resource Conservation and Recovery Act. Based on a preliminary evaluation, the Company believes the rule will not have a material effect on operations at Boardman, which produce dry CCRs. Disposal of the dry CCRs occurs at an on-site landfill that is currently permitted and regulated by the State of Oregon under requirements similar to the new CCR rule. The Company has been informed, however, that this rule will have an effect on operations at Colstrip, which produce wet CCRs. The operator of Colstrip has provided the Company with an initial cost estimate related to the impacts of the new CCR rule. As a result, during the second quarter of 2015, the Company recorded an increase to the existing Colstrip AROs in the amount of $15 million, with a corresponding increase in the cost basis of the plant, included in Electric utility plant, net on the consolidated balance sheet. PGE plans to seek recovery in customer prices of the incremental costs associated with the new rule. For further information, see *“Asset Retirement Obligations”* in Note 2, Balance Sheet Components, in the Notes to Condensed Consolidated Financial Statements.

The following discussion highlights certain regulatory items that have impacted the Company’s revenues, results of operations, or cash flows for the second quarter of 2015 compared to the second quarter of 2014 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. As part of its 2015 GRC, PGE included a projected $60 million reduction in power costs in its request for an overall increase in revenues. The power cost portion of the request was moved to a separate docket at the OPUC and was approved and included in the overall $15 million annual revenue increase authorized by the OPUC in the Company’s 2015 GRC with new prices beginning January 1, 2015.

Under the PCAM for 2014, 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 2014 during the latter half of 2015 with any resulting refund to or collection from customers to occur during 2016.

Renewable Resource Costs—Pursuant to its renewable adjustment clause mechanism (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 2014, PGE submitted to the OPUC a RAC filing requesting deferral and recovery of the net revenue requirement of Tucannon River in the event that the facility were to come online prior to the inclusion of the project in base rates as proposed in the 2015 GRC. The Company utilized the RAC to record the revenue requirement, which was estimated to be approximately $1 million, for the period from December 15, 2014, when the facility was placed into service, until December 31, 2014. On April 15, 2015, the OPUC issued an order approving the deferral amount to be amortized and collected from customers in prices during the period July 1, 2015 through December 31, 2015.

On April 1, 2015, PGE submitted to the OPUC a RAC filing requesting revenue requirements related to a new, 1.2 MW solar facility. Concurrent with this filing, PGE also requested authorization to engage in a property sale as part of a sale-leaseback agreement for the facility. The Company estimates that overall annual impact to customer prices of this RAC filing will be an approximately $2 million reduction in revenues.

Decoupling—The decoupling mechanism, which the OPUC has authorized through 2016, is intended to provide for recovery of margin lost as a result of a reduction in electricity sales attributable to energy efficiency 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 approved general rate case.

Accordingly, collection of the estimated $5 million recorded during 2013 is expected to occur during 2015. Refund of the $5 million recorded during 2014, subject to OPUC approval, is expected to occur over a one year period, which will begin January 1, 2016.

For the six months ended June 30, 2015, the Company has recorded an estimated collection of $2 million. Any resulting collection from (or refund to) customers for the 2015 year would begin January 1, 2017.

Capital Deferral—In the 2011 General Rate Case (2011 GRC), the OPUC authorized the Company to defer the costs associated with four capital projects that were not completed at the time the 2011 GRC was approved. In 2012, PGE deferred such costs and recorded a regulatory asset of $16 million for potential future recovery in customer prices with an offsetting credit to Depreciation and amortization expense. The OPUC authorized recovery of the deferred costs over a one-year period beginning January 1, 2014. In 2013, the Company recorded additional deferred costs and interest associated with these projects totaling $19 million, with recovery of such amounts included in customer prices over a one year period beginning January 1, 2015. Beginning January 1, 2014, the costs of these projects were reflected in the Company’s rate base.

*Boardman Operating Life Adjustmen*t—As part of the 2014 GRC, the incremental depreciation expense that resulted from the shortened Boardman life was rolled into base customer prices, while recovery of the decommissioning costs continue under this separate tariff. During the second quarter of 2014, the OPUC approved the request for recovery of additional decommissioning costs that resulted from the acquisition of the additional 15% interest in Boardman on December 31, 2013, which was expected to result in approximately $3 million additional revenue in 2014. The tariff also provides for annual updates to decommissioning revenue requirements with revised prices to take effect each January 1.

On December 31, 2014, PGE acquired an additional 10% ownership share in Boardman previously held by one of the former co-owners. In September 2014, the Company had submitted to the OPUC a request for approval of the annual update of the decommissioning revenue requirements for 2015, which included the additional decommissioning costs related to this incremental 10% ownership. The OPUC authorized the acquisition of the 10% interest in the 2015 GRC order, with recovery of the incremental share of decommissioning costs authorized in the tariff effective January 1, 2015. PGE received authorization from the FERC in November 2014 to consummate the acquisition.

Integrated Resource Plan (IRP)—In December 2014, the OPUC acknowledged PGE’s latest IRP (2013 IRP), which outlines the Company’s expectations for resource needs and resource portfolio performance over the next 20 years. The 2013 IRP includes an “Action Plan,” which covers PGE’s proposed actions over the next two to four years (through 2017). Over this period of time, the Company projects energy requirements and energy available through its generating resources and long-term power purchase agreements to be in approximate balance.

The Action Plan includes the following, among other components, between 2014 and 2017:

- Seek renewal, or partial renewal, of expiring power purchase agreements for energy generated from hydroelectric projects, if available and cost-effective for our customers;
- Acquire a total of 114 MWa of energy efficiency through continuation of Energy Trust of Oregon programs, with a target increase of 124 MWa if legislation and regulation allow;
- Acquire an additional 25 MW of demand response and 23 MW of dispatchable standby generation from customers to help manage peak load conditions and other supply contingencies; and
- Perform various research and studies related to load forecast and energy efficiency projections, distributed generation resources within PGE's service territory, the viability of large-scale biomass operations, fuel supply, operational flexibility requirements and analytical tools, cost-benefit analysis of Energy Imbalance Market participation, RPS compliance strategies and potential impacts of compliance with the EPA's proposed Clean Power Plan rules concerning reductions in carbon dioxide emissions from existing fossil fuel-fired power plants in preparation for the next IRP.

The 2013 IRP also incorporates the three new energy and capacity resources, PW2 and Tucannon River, both of which were placed into service in December 2014, and Carty, which is under construction and expected to be placed in service in the second quarter of 2016.

Beyond 2018, PGE may need additional resources in order to meet the 2020 and 2025 RPS requirements and to replace energy from Boardman, which is scheduled to cease coal-fired operations at the end of 2020. Additional post-2018 actions may also be needed to offset expiring power purchase agreements and to back-up variable energy resources, such as wind generation facilities. These actions are expected to be identified in a future IRP. PGE expects to file its next IRP with the OPUC in 2016.

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, 2014, filed with the SEC on February 13, 2015.

Results of Operations

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

	Three Months Ended June 30,				Six Months Ended June 30,			
	2015		2014		2015		2014	
Revenues, net	$ 450	100%	$ 423	100%	$ 923	100%	$ 916	100%
Purchased power and fuel	148	33	142	34	309	33	326	36
Gross margin	302	67	281	66	614	67	590	64
Other operating expenses:								
Generation, transmission and distribution	66	15	67	16	128	14	121	13
Administrative and other	60	13	56	13	120	13	110	12
Depreciation and amortization	76	17	73	17	151	17	148	16
Taxes other than income taxes	28	6	27	6	58	6	55	6
Total other operating expenses	230	51	223	52	457	50	434	47
Income from operations	72	16	58	14	157	17	156	17
Interest expense*	28	6	23	5	58	6	48	5
Other income:								
Allowance for equity funds used during construction	5	1	9	2	9	1	15	1
Miscellaneous income, net	1	—	1	—	2	—	—	—
Other income, net	6	1	10	2	11	1	15	1
Income before income tax expense	50	11	45	11	110	12	123	13
Income tax expense	15	3	10	3	25	3	30	3
Net income	$ 35	8%	$ 35	8%	$ 85	9%	$ 93	10%

* Net of an allowance for borrowed funds used during construction of $3 million and $5 million for the three months ended June 30, 2015 and 2014, respectively, and $6 million and $9 million for the six months ended June 30, 2015 and 2014, respectively.

Net income was $35 million for the second quarter of 2015 and 2014, with diluted earnings per share of $0.44 and $0.43, respectively. Favorable impacts to Net income for the second quarter of 2015 from increased energy deliveries across all customer classes and the inclusion of two new generation resources in 2015 customer prices were largely offset by the impact of lower NVPC in the second quarter of 2014 when compared to the second quarter of 2015. Actual NVPC approximated baseline NVPC for the second quarter of 2015, while actual NVPC was $11 million below baseline NVPC for the second quarter of 2014 when the region experienced more favorable hydro conditions.

Net income was $85 million, or $1.07 per diluted share, for the first half of 2015, compared with $93 million, or $1.16 per diluted share, for the first half of 2014. The decrease in Net income was driven by a 4.5% decrease in residential energy deliveries resulting from warmer weather in 2015, combined with the impact of lower NVPC in the first half of 2014 when compared to the first half of 2015. Actual NVPC was $2 million below baseline NVPC for the first half of 2015, compared to $14 million below baseline for the first half of 2014. The differences between actual and baseline NVPC for each period is largely due to the differences in actual energy received from hydro and wind generating resources compared to projected levels included in the respective AUT.

Favorable impacts to net income for the first half of 2015 from increased industrial and commercial energy deliveries and the inclusion of two new generation resources in 2015 customer prices partially offset the unfavorable impacts to net income discussed above.

Three Months Ended June 30, 2015 Compared with the Three Months Ended June 30, 2014

Revenues, energy deliveries (presented in MWh), and the average number of retail customers were as follows for the periods presented:

	Three Months Ended June 30,			
	2015		2014	
Revenues [1] (dollars in millions):				
Retail:				
Residential	$ 200	44 %	$ 188	44 %
Commercial	167	37	159	38
Industrial	57	13	53	13
Subtotal	424	94	400	95
Other retail revenues, net	(4)	(1)	(4)	(1)
Total retail revenues	420	93	396	94
Wholesale revenues	18	4	17	4
Other operating revenues	12	3	10	2
Total revenues	$ 450	100 %	$ 423	100 %
Energy deliveries [2] (MWh in thousands):				
Retail:				
Residential	1,628	31 %	1,552	32 %
Commercial	1,880	36	1,814	37
Industrial	1,161	23	1,057	21
Total retail energy deliveries	4,669	90	4,423	90
Wholesale energy deliveries	538	10	512	10
Total energy deliveries	5,207	100 %	4,935	100 %
Average number of retail customers:				
Residential	740,845	87 %	734,716	87 %
Commercial	105,999	13	105,662	13
Industrial	261	—	259	—
Total	847,105	100 %	840,637	100 %

(1) Includes revenues from customers who purchase their energy from the Company and revenues from the delivery of energy to those commercial and industrial customers that purchase their energy from ESSs.
(2) Includes energy sold to retail customers and energy delivered to those commercial and industrial customers that purchased their energy from ESSs.

Total revenues increased $27 million, or 6%, for the second quarter of 2015 compared with the second quarter of 2014, largely due to the $24 million increase in Retail revenues resulting from the following:

- A $22 million increase related to 5.6% higher volumes of energy delivered, with increases in energy deliveries across all customer classes and consisting of 4.9% in residential, 3.6% in commercial, and 9.8% in industrial. After adjusting for the effects of weather, total retail energy deliveries were up 5.8% for the second quarter of 2015 compared with the second quarter of 2014; and
- A $9 million increase related to a 2.3% increase in average customer prices largely resulting from the 2015 GRC, which became effective January 1, 2015; partially offset by

- A $7 million decrease related to various supplemental tariff changes, including the return of $5 million to customers in the second quarter of 2015 of proceeds received in connection with the settlement of a legal matter related to the operation of the Independent Spent Fuel Storage Installation (ISFSI) at the Trojan nuclear power plant, which was closed in 1993 (offset in Depreciation and amortization).

Total heating degree-days for second quarter of 2015 were 3% lower than the second quarter of 2014 and 28% below average, while total cooling degree-days for the second quarter of 2015 were 263% higher than the second quarter of 2014 and 196% above average. The following table indicates the number of heating and cooling degree-days for the second quarters of 2015 and 2014, along with 15-year averages provided by the National Weather Service, as measured at Portland International Airport:

	Heating Degree-days		**Cooling Degree-days**	
	2015	**2014**	**2015**	**2014**
April	361	332	2	3
May	133	136	20	25
June	19	62	185	29
Second quarter	513	530	207	57
15-year average for the year-to-date	713	713	70	70

Wholesale revenues result from sales of electricity to utilities and power marketers in conjunction with the Company’s efforts to secure reasonably-priced power for its retail customers, manage risk, and administer its current long-term wholesale contracts. Such sales can vary significantly from period to period as a result of economic conditions, power and fuel prices, hydro and wind conditions, and customer demand. The $1 million, or 6%, increase in Wholesale revenues for the second quarter of 2015 compared with the second quarter of 2014 consisted of a 5% increase in wholesale sales volume, combined with a 3% increase in average wholesale price.

Purchased power and fuel expense increased $6 million, or 4%, for the second quarter of 2015 compared with the second quarter of 2014, and consisted of $9 million related to a 7% increase in total system load, partially offset by $3 million related to a 1% decrease in the average variable power cost per MWh.

The decrease in the average variable power cost to $29.65 per MWh in the second quarter of 2015 from $30.05 per MWh in the second quarter of 2014 was largely due to an increase in lower-cost thermal generation during the second quarter of 2015. Thermal generation was economically displaced with purchased power during the majority of the second quarter of 2014. In addition, an increase in the Company’s wind generating resources from the addition of Tucannon River, partially offset by a decrease in energy received from hydro resources, contributed to the decrease in the average variable power cost per MWh.

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 June 30,			
	2015		2014	
Sources of energy (MWh in thousands):				
Generation:				
Thermal:				
Coal	727	15%	367	8%
Natural gas	984	20	43	1
Total thermal	1,711	35	410	9
Hydro	318	6	448	9
Wind	515	10	404	9
Total generation	2,544	51	1,262	27
Purchased power:				
Term	1,376	27	2,562	54
Hydro	383	8	489	11
Wind	96	2	102	2
Spot	621	12	294	6
Total purchased power	2,476	49	3,447	73
Total system load	5,020	100%	4,709	100%
Less: wholesale sales	(538)		(512)	
Retail load requirement	4,482		4,197	

Energy received from hydro resources during the second quarter of 2015, from both PGE-owned generating plants and purchased from mid-Columbia projects, decreased 25% compared with the same period of 2014, and represented 16% and 22% of the Company’s retail load requirement for the second quarters of 2015 and 2014, respectively. During the second quarter of 2015, total energy received from hydro resources fell below projected levels included in the Company’s AUT by 23%, compared with the second quarter of 2014, which exceeded projected levels included in the AUT for 2014 by 4%.

Energy received from PGE-owned wind generating resources (Biglow Canyon and Tucannon River) increased 27% in the second quarter of 2015 compared with the same period of 2014. The increase in such energy received is due to the addition of the Tucannon River wind generating resource in December 2014, which was partially offset by an 18% decline in energy received from Biglow Canyon. Energy received from these wind generating resources represented 11% of the Company’s retail load requirement for the second quarter of 2015, and 10% for the second quarter of 2014. During the second quarters, energy received from wind resources fell short of projected levels included in the AUT by 20% for 2015 and 1% for 2014.

The following table presents the forecast of the April-to-September 2015 runoff (issued July 20, 2015), along with actual for 2014, at particular points of major rivers relevant to PGE's hydro resources (as a percentage of normal, as measured over the 30-year period from 1981 through 2010):

	Runoff as a Percent of Normal *	
Location	2015 Forecast	2014 Actual
Columbia River at The Dalles, Oregon	67%	108%
Mid-Columbia River at Grand Coulee, Washington	74	110
Clackamas River at Estacada, Oregon	50	97
Deschutes River at Moody, Oregon	86	98

* Volumetric water supply percentages 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, which consists of Purchased power and fuel expense net of Wholesale revenues, increased $5 million for the second quarter of 2015 compared with the second quarter of 2014. The increase consisted of a 7% increase in total system load, partially offset by a 1% decline in the average variable power cost per MWh and a 5% increase in wholesale sales volume. For the second quarter of 2015, actual NVPC approximated baseline NVPC, while actual NVPC for the second quarter of 2014 was $11 million below baseline NVPC.

Generation, transmission and distribution expense decreased $1 million, or 1%, in the second quarter of 2015 compared with the second quarter of 2014, driven by the timing of the annual planned maintenance outage at Boardman, which occurred in the first quarter of 2015 as opposed the second quarter of 2014, thus reflecting a $3 million reduction in 2015. Partially offsetting this reduction were $2 million higher operation and maintenance expenses in 2015 driven by the addition of PW2 and Tucannon River and $1 million more information technology expenses.

Administrative and other expense increased $4 million, or 7%, in the second quarter of 2015 compared with the second quarter of 2014. The increase resulted from a combination of higher expenses for legal and environmental services, injuries and damages, pension, information technology and other miscellaneous items partially offset by a $2 million reduction in expense resulting from a reduction in the provision for bad debt expense.

Depreciation and amortization expense increased $3 million, or 4%, in the second quarter of 2015 compared with the second quarter of 2014. A $6 million increase resulting from capital additions and $2 million higher expense due to changes in asset retirement obligation assumptions was largely offset by $5 million in amortization of deferred regulatory liabilities for the Trojan spent fuel settlement and ISFSI tax credits. The reduction in expenses resulting from the amortization of the regulatory liabilities is offset by corresponding reductions in revenues.

Taxes other than income taxes expense increased $1 million, or 4%, in the second quarter of 2015 compared with the second quarter of 2014, primarily due to higher franchise fees resulting from higher revenues.

Interest expense increased $5 million, or 22%, in the second quarter of 2015 compared with the second quarter of 2014, with $3 million related to a 16% increase in the average balance of debt outstanding and $2 million related to lower allowance for borrowed funds used during construction. In December 2014, PW2 and Tucannon River were placed into service resulting in a lower average CWIP balance during 2015.

Other income, net declined $4 million in the second quarter of 2015 compared with the second quarter of 2014, driven by a decrease in the allowance for equity funds used during construction resulting from the lower average CWIP balance.

Income tax expense was $15 million in the second quarter of 2015 compared with $10 million in the second quarter of 2014, with effective tax rates of 30.0% and 22.2%, respectively. Higher pre-tax income accounted for a $2 million change while the remainder of the increase in both the income tax expense and the effective tax rate can be attributed to the tax impact of lower AFDC equity.

Six Months Ended June 30, 2015 Compared with the Six Months Ended June 30, 2014

Revenues, energy deliveries (presented in MWh), and the average number of retail customers were as follows for the periods presented:

	Six Months Ended June 30,			
	2015		2014	
Revenues [(1)] (dollars in millions):				
Retail:				
Residential	$ 434	47 %	$ 445	48 %
Commercial	322	35	317	35
Industrial	113	12	105	11
Subtotal	869	94	867	94
Other retail revenues, net	(2)	—	(2)	—
Total retail revenues	867	94	865	94
Wholesale revenues	37	4	34	4
Other operating revenues	19	2	17	2

Total revenues	$ 923	100 %	$ 916	100 %
Energy deliveries [(2)] (MWh in thousands):				
Retail:				
Residential	3,559	34 %	3,726	36 %
Commercial	3,640	34	3,595	35
Industrial	2,255	21	2,058	20
Total retail energy deliveries	9,454	89	9,379	91
Wholesale energy deliveries	1,118	11	893	9
Total energy deliveries	10,572	100 %	10,272	100 %
Average number of retail customers:				
Residential	740,188	88 %	734,218	88 %
Commercial	105,082	12	104,674	12
Industrial	262	—	260	—
Total	845,532	100 %	839,152	100 %

(1) Includes revenues from customers who purchase their energy from the Company and revenues from the delivery of energy to those commercial and industrial customers that purchase their energy from ESSs.
(2) Includes energy sold to retail customers and energy delivered to those commercial and industrial customers that purchased their energy from ESSs.

Total revenues increased $7 million, or 1%, for the first half of 2015 compared with the first half of 2014, with $2 million higher in Retail revenues resulting from the following:

- An $8 million increase related to a 1% increase in average customer prices largely resulting from the 2015 GRC, which became effective January 1, 2015; and
- A $7 million increase related to 0.8% higher volumes of energy delivered, with increases of 9.6% and 1.3% in industrial and commercial energy deliveries, respectively, partially offset by a 4.5% decrease in residential energy deliveries. After adjusting for the effects of weather, total retail energy deliveries were up 4.9% for the first half of 2015 compared with the first half of 2014; partially offset by

- A $13 million decrease related to various supplemental tariff changes, including the return of $9 million to customers in the first half of 2015 of proceeds received in connection with the settlement of a legal matter related to the operation of the ISFSI at the Trojan nuclear power plant, which was closed in 1993 (offset in Depreciation and amortization).

Total heating degree-days for the first half of 2015 were 18% lower than the first half of 2014 and 23% below average, while cooling degree days were 263% higher than the first half of 2014 and 196% above average. The following table indicates the number of heating degree-days for the first half of 2015 and 2014, along with 15-year averages provided by the National Weather Service, as measured at Portland International Airport:

	Heating Degree-days		**Cooling Degree-days**	
	2015	**2014**	**2015**	**2014**
First quarter	1,481	1,891	—	—
Second quarter	513	530	207	57
Year-to-date	1,994	2,421	207	57
15-year average for the year-to-date	2,577	2,577	70	70

Wholesale revenues for the first half of 2015 increased $3 million, or 9%, from the first half of 2014, and consisted of $9 million related to a 25% increase in wholesale sales volume, partially offset by $6 million related to a 13% decrease in average wholesale price.

Purchased power and fuel expense decreased $17 million, or 5%, for the first half of 2015 compared with the first half of 2014, and consisted of $24 million related to a 7% decrease in the average variable power cost per MWh, partially offset by $7 million related to a 2% increase in total system load.

The decrease in the average variable power cost to $30.13 per MWh in the first half of 2015 from $32.42 per MWh in the first half of 2014 was driven by a 7% decline in the average cost per MWh of purchased power. In addition, the economic displacement of Boardman during the first quarter of 2015 combined with an increase in energy received from the Company’s wind generating resources contributed to the decrease in the average variable power cost per MWh.

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

	Six Months Ended June 30,			
	2015		2014	
Sources of energy (MWh in thousands):				
Generation:				
Thermal:				
Coal	1,211	12%	1,600	16%
Natural gas	1,654	16	991	10
Total thermal	2,865	28	2,591	26
Hydro	796	8	981	10
Wind	803	8	621	6
Total generation	4,464	44	4,193	42
Purchased power:				
Term	2,876	28	3,782	38
Hydro	913	9	867	8
Wind	153	1	165	2
Spot	1,861	18	1,041	10
Total purchased power	5,803	56	5,855	58
Total system load	10,267	100%	10,048	100%
Less: wholesale sales	(1,118)		(893)	
Retail load requirement	9,149		9,155	

Energy received from hydro resources during the first half of 2015, from both PGE-owned generating plants and purchased from mid-Columbia projects, decreased 8% compared with the same period of 2014, and represented 19% and 20% of the Company’s retail load requirement for the first half of 2015 and 2014, respectively. Through June, total energy received from hydro resources fell below projected levels included in the Company’s AUT by 6% for 2015, compared with the same period of 2014, which exceeded projected levels included in the AUT for 2014 by 2%.

Energy received from PGE-owned wind generating resources (Biglow Canyon and Tucannon River) increased 29% in the first half of 2015 compared with the same period of 2014. The increase in such energy received is due to the addition of the Tucannon River wind generating resource in December 2014, which was partially offset by a 24% decline in energy received from Biglow Canyon. Energy received from these wind generating resources represented 9% of the Company’s retail load requirement for the first half of 2015, compared with 7% for the first half of 2014. Through June, energy received from wind resources fell short of projected levels included in the AUT by 27% for 2015 and 5% for 2014.

Actual NVPC for the first half of 2015 decreased $20 million when compared with the first half of 2014. The decrease was driven by a 7% decline in the average variable power cost per MWh, combined with a 25% increase in wholesale sales volume. Partially offsetting these decreases to NVPC was a 2% increase in total system load combined with a 13% decrease in the average wholesale sales price. For the first half of 2015 and 2014, actual NVPC was $2 million and $14 million, respectively, below baseline NVPC.

Generation, transmission and distribution expense increased $7 million, or 6%, in the first half of 2015 compared with the first half of 2014. In 2015, PGE incurred $4 million more operation and maintenance expenses driven by the addition of PW2 and Tucannon River. Information technology expenses were $3 million higher while storm and service restoration costs, straight time labor, and IRP study costs combined to add $3 million in the first half of 2015. The timing of the repair and maintenance work during the annual planned outage and economic shutdown at Boardman in 2015, coupled with the unplanned outages at Colstrip in January 2014 and Beaver in 2015, reduced expenses $3 million in the first half of 2015.

Administrative and other expense increased $10 million, or 9%, in the first half of 2015 compared with the first half of 2014. The increase was due in large part to the combination of $3 million higher information technology expenses recorded in 2015, an increase of $3 million in non-labor and outside services expenses, and a $2 million increase in compensation and benefits.

Depreciation and amortization expense increased $3 million in the first half of 2015 compared with the first half of 2014. A $12 million higher expense resulting from capital additions was largely offset by $11 million in amortization of deferred regulatory liabilities for the Trojan spent fuel settlement and tax credits. The remainder of the change resulted from an increase in ARO expenses and amortization of capital deferrals partially offset by gains recorded on the sale of assets. The reduction in expenses resulting from the amortization of the regulatory liabilities is directly offset by corresponding reductions in revenues.

Taxes other than income taxes expense increased $3 million, or 5%, in the first half of 2015 compared with the first half of 2014, as a $2 million increase resulted primarily from higher property taxes attributed to the addition of Port Westward 2 and Tucannon River and franchise fees increased $1 million due to higher revenues.

Interest expense increased $10 million, or 21%, in the first half of 2015 compared with the first half of 2014, with $7 million related to a 17% increase in the average balance of debt outstanding and $3 million related to lower allowance for borrowed funds used during construction. In December 2014, PW2 and Tucannon River were placed into service resulting in a lower average CWIP balance during 2015.

Other income, net was $11 million in the first half of 2015 compared with $15 million in the first half of 2014, as a $6 million decrease in the allowance for equity funds used during construction resulting from the lower average CWIP balance was partially offset by an increase in earnings from the Non-qualified benefit plan trust assets.

Income tax expense was $25 million in the first half of 2015 compared with $30 million in the first half of 2014, with effective tax rates of 22.7% and 24.4%, respectively. Lower pre-tax income largely accounted for the $5 million decrease in income tax expense. A $4 million increase in production tax credits in 2015, resulting primarily from the addition of Tucannon River wind generation, was substantially offset by the tax impact of lower AFDC equity.

Liquidity and Capital Resources

Capital Requirements

The following table presents PGE's estimated capital expenditures and contractual maturities of long-term debt for 2015 through 2019 (in millions, excluding AFDC):

	2015		2016	2017	2018	2019
Ongoing capital expenditures (1)	$ 411	(2)	$ 342	$ 362	$ 296	$ 284
Carty Generating Station	165		42	—	—	—
Hydro licensing and construction (3)	22		12	4	2	1
Total capital expenditures	$ 598	(4)	$ 396	$ 366	$ 298	$ 285
Long-term debt maturities (5)	$ 442		$ —	$ 58	$ 75	$ 300

(1) Consists primarily of upgrades to, and replacement of, generation, transmission, and distribution infrastructure, as well as new customer connections. For 2015 through 2019, $136 million relates to the implementation of the Company's new customer information and meter data management systems.
(2) Includes $42 million for the completion of construction of PW2 and Tucannon River.
(3) Relates primarily to modifications to PGE's hydro facilities to enhance fish passage and survival, as required by conditions contained in the operating licenses.
(4) Includes preliminary engineering and removal costs, which are included in other net operating activities in the condensed consolidated statements of cash flows.
(5) Reflects $67 million of FMBs in 2015, which were previously presented in 2016. Such FMBs had an original maturity date in 2016 but were repaid in 2015.

For additional information on Carty, see *"Capital Requirements and Financing"* in the Overview section of this Item 2. 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):

	Six Months Ended June 30,	
	2015	2014
Cash and cash equivalents, beginning of period	$ 127	$ 107
Net cash provided by (used in):		
Operating activities	248	302
Investing activities	(238)	(494)
Financing activities	(15)	182
Decrease in cash and cash equivalents	(5)	(10)
Cash and cash equivalents, end of period	$ 122	$ 97

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, as well as the nature and amount of 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 first half of 2015 declined $54 million when compared with the first half of 2014. Such decrease was largely due to an increase in margin deposits, a decrease in cash received from Bonneville Power Administration to be returned to customers pursuant to the Residential Exchange Program, and other changes in working capital items as a result of amount and timing of transactions.

Cash provided by operations includes the recovery in customer prices of non-cash charges for depreciation and amortization. PGE estimates that such charges in 2015 will range from $300 million to $310 million. Combined with other sources, total cash expected to be provided by operations is estimated to range from $455 million to $495 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 first half of 2015 decreased $256 million when compared with the first half of 2014. Such decrease was largely due to a $188 million decrease in capital expenditures, combined with a distribution from the Nuclear decommissioning trust in the amount of $50 million to be returned to customers over the three-year period that began January 1, 2015 and the collection of a sales tax refund in the amount of $23 million related to Tucannon River in the first half of 2015.

The Company plans approximately $598 million of capital expenditures for 2015, including $165 million related to the construction of Carty. PGE plans to fund the 2015 capital expenditures with cash expected to be generated from operations during 2015, as discussed above, as well as with proceeds received from the issuances of equity and debt securities. For additional information, see *"Capital Requirements"* and *"Debt and Equity Financings"* in the Liquidity and Capital Resources section of this 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 first half of 2015, net cash used in financing activities consisted of the repayment of long-term debt of $387 million and the payment of dividends of $44 million, partially offset by proceeds received from the issuances of common stock of $271 million and FMBs of $145 million. During the first half of 2014, net cash provided by financing activities consisted of net proceeds received from the issuances of term bank loans of $225 million, partially offset by the payment of dividends of $43 million.

Dividends on Common Stock

While PGE expects to pay regular quarterly dividends on its common stock, the declaration of any dividends is at the discretion of the Company's Board of Directors. The amount of any dividend declaration will depend 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 2015 consist of the following:

Declaration Date	Record Date	Payment Date	Dividends Declared Per Common Share
February 18, 2015	March 25, 2015	April 15, 2015	$ 0.28
May 6, 2015	June 25, 2015	July 15, 2015	0.30
July 23, 2015	September 25, 2015	October 15, 2015	0.30

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, credit ratings, 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 2015, PGE expects to fund estimated capital expenditures and maturities of long-term debt with cash from operations (which is expected to range from $455 million to $495 million), issuances of debt securities of up to $250 million and the previously disclosed June 10, 2015 issuance of 10,400,000 shares of common stock under the EFSA in exchange for net proceeds of $271 million. The actual timing and amount of future issuances of debt and equity securities will be dependent upon the timing and amount of capital expenditures.

Short-term Debt. PGE has approval from the FERC to issue short-term debt up to a total of $900 million through February 6, 2016. During the first quarter of 2015, the Company determined that a $500 million aggregate revolving credit facility capacity would be sufficient to meet its liquidity needs and accordingly, in March 2015, reduced its aggregate revolving credit capacity from $700 million to $500 million. As of June 30, 2015, PGE has a $500 million revolving credit facility scheduled to expire November 2019. This revolving credit facility supplements operating cash flow and provides a primary source of liquidity. Pursuant to the terms of the agreement, the revolving credit facility may be used for general corporate purposes, backup for commercial paper borrowings, and the issuance of standby letters of credit.

As of June 30, 2015, PGE had no borrowings or commercial paper outstanding, $38 million of letters of credit issued, and an aggregate available capacity under the credit facility of $462 million.

PGE has two $30 million letter of credit facilities under which the Company can request letters of credit for original terms not to exceed one year. The issuance of such letters of credit is subject to the approval of the issuing institution. As of June 30, 2015, $59 million of letters of credit had been issued under these facilities.

Long-term Debt. During the first half of 2015, PGE received aggregate proceeds of $145 million related to the issuance of long-term debt and repaid long-term debt in an aggregate amount of $387 million as follows:

- In January, the Company issued $75 million of 3.55% Series FMBs, due 2030, and repaid $70 million of 3.46% Series FMBs;
- In February, PGE repaid $50 million of long-term bank loans;
- In May, the Company issued $70 million of 3.50% Series FMBs and repaid $67 million of 6.80% Series FMBs, due January 2016; and

- In June, PGE repaid $200 million of long-term bank loans.

As of June 30, 2015, total long-term debt outstanding was $2,259 million, including current maturities of $55 million.

On July 10, 2015, the Company repaid the remaining outstanding balance of long-term bank loans in the amount of $55 million.

Equity. During the second quarter of 2015, PGE physically settled in full the EFSA by issuing 10,400,000 shares of PGE common stock in exchange for cash of $271 million.

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 debt ratings and facilitates access to long-term capital at favorable interest rates. The Company's common equity ratios were 49.6% and 43.3% as of June 30, 2015 and December 31, 2014, respectively.

Credit Ratings and Debt Covenants

PGE's ratings are investment grade by Moody's Investors Service (Moody's) and Standard and Poor's Ratings Services (S&P), with current ratings and outlook as follows:

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

Should Moody's and/or S&P reduce their credit rating on PGE's unsecured debt to below investment grade, the Company could be subject to requests by certain of its wholesale, commodity and related 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, and are based on the contract terms and commodity prices and can vary from period to period. These cash deposits 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 June 30, 2015, PGE had posted approximately $75 million of collateral with these counterparties, consisting of $28 million in cash and $47 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 June 30, 2015, the approximate amount of additional collateral that could be requested upon a single agency downgrade to below investment grade was approximately $108 million, and decreases to approximately $64 million by December 31, 2015 and $27 million by December 31, 2016. The amount of additional collateral that could be requested upon a dual agency downgrade to below investment grade was approximately $215 million at June 30, 2015, and decreases to approximately $133 million by December 31, 2015 and $66 million by December 31, 2016.

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 securing the FMBs. PGE estimates that on June 30, 2015, under the most restrictive issuance test in the Indenture of Mortgage and Deed of Trust, the Company could have issued up to approximately $924 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 of Mortgage and Deed of Trust 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 June 30, 2015, the Company's debt-to-total capital ratio, as calculated under the credit agreement, was 50.4%.

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 2015 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, 2014, filed with the SEC on February 13, 2015. Such obligations have not changed materially as of June 30, 2015, except for interest on long-term debt. During the six months ended June 30, 2015, PGE issued FMBs in the amount of $145 million, consisting of $75 million of 3.55% Series and $70 million of 3.50% Series. As a result, interest on long-term debt increased as follows: $4 million for 2015; $5 million for 2016 through 2019; and $64 million for Thereafter.

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, 2014, filed with the SEC on February 13, 2015.

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 June 30, 2015, 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, 2014, filed with the SEC on February 13, 2015.

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.

In June 2015, based on a motion filed by PGE, the Marion County Circuit Court lifted the abatement and set oral argument on the Company’s motion for Summary Judgment to occur on July 27, 2015.

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, 2014, filed with the SEC on February 13, 2015.

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.
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:	July 27, 2015	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:	July 27, 2015	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:	July 27, 2015	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 June 30, 2015, as filed with the Securities and Exchange Commission on July 28, 2015 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: July 27, 2015	Date: July 27, 2015