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

FORM 10-Q

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

For the quarterly period ended **September 30, 2013**

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 October 28, 2013 is 78,067,553 shares.

PORTLAND GENERAL ELECTRIC COMPANY
FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2013

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DEFINITIONS

The following abbreviations and acronyms are used throughout this document:

Abbreviation or Acronym	Definition
AUT	Annual Power Cost Update Tariff
Biglow Canyon	Biglow Canyon wind farm
Carty	Carty Generating Station natural gas-fired generating plant
Cascade Crossing	Cascade Crossing Transmission Project
Colstrip	Colstrip Steam Electric Station coal-fired generating plant
EFSA	Equity forward sale agreement
EPA	United States Environmental Protection Agency
ESS	Electricity Service Supplier
FERC	Federal Energy Regulatory Commission
FMB	First Mortgage Bond
IRP	Integrated Resource Plan
kV	Kilovolt = one thousand volts of electricity
Moody's	Moody's Investors Service
MW	Megawatts
MWh	Megawatt hours
NVPC	Net Variable Power Costs
OPUC	Public Utility Commission of Oregon
PCAM	Power Cost Adjustment Mechanism
PW2	Port Westward Unit 2 natural gas-fired generating plant
RFP	Request for proposal
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 September 30,		Nine Months Ended September 30,	
	2013	**2012**	**2013**	**2012**
Revenues, net	$ 435	$ 450	$ 1,311	$ 1,342
Operating expenses:				
Purchased power and fuel	190	182	538	533
Production and distribution	54	49	169	153
Cascade Crossing transmission project	—	—	52	—
Administrative and other	49	50	158	160
Depreciation and amortization	62	63	186	188
Taxes other than income taxes	27	24	79	77
Total operating expenses	382	368	1,182	1,111
Income from operations	53	82	129	231
Interest expense	25	27	75	82
Other income, net	7	1	13	6
Income before income tax expense	35	56	67	155
Income tax expense	4	19	10	43
Net income and Comprehensive income	31	37	57	112
Less: net loss attributable to noncontrolling interests	—	(1)	(1)	(1)
Net income and Comprehensive income attributable to Portland General Electric Company	$ 31	$ 38	$ 58	$ 113
Weighted-average shares outstanding (in thousands):				
Basic	77,637	75,528	76,401	75,486
Diluted	78,330	75,541	76,703	75,500
Earnings per share—basic and diluted	$ 0.40	$ 0.50	$ 0.76	$ 1.49
Dividends declared per common share	$ 0.275	$ 0.270	$ 0.820	$ 0.805

See accompanying notes to condensed consolidated financial statements.

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

	September 30, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 91	$ 12
Accounts receivable, net	137	152
Unbilled revenues	67	97
Inventories	72	78
Margin deposits	36	46
Regulatory assets—current	99	144
Other current assets	63	93
Total current assets	**565**	**622**
Electric utility plant, net	4,659	4,392
Regulatory assets—noncurrent	504	524
Nuclear decommissioning trust	82	38
Non-qualified benefit plan trust	34	32
Other noncurrent assets	47	62
Total assets	**$ 5,891**	**$ 5,670**

See accompanying notes to condensed consolidated financial statements.

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

	September 30, 2013	December 31, 2012
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 99	$ 98
Liabilities from price risk management activities—current	89	127
Short-term debt	—	17
Current portion of long-term debt	—	100
Accrued expenses and other current liabilities	192	179
Total current liabilities	**380**	**521**
Long-term debt, net of current portion	1,761	1,536
Regulatory liabilities—noncurrent	852	765
Deferred income taxes	565	588
Unfunded status of pension and postretirement plans	253	247
Non-qualified benefit plan liabilities	103	102
Asset retirement obligations	96	94
Liabilities from price risk management activities—noncurrent	71	73
Other noncurrent liabilities	17	14
Total liabilities	**4,098**	**3,940**
Commitments and contingencies (see notes)		
Equity:		
Portland General Electric Company shareholders' equity:		
Preferred stock, no par value, 30,000,000 shares authorized; none issued and outstanding as of September 30, 2013 and December 31, 2012	—	—
Common stock, no par value, 160,000,000 shares authorized; 78,067,299 and 75,556,272 shares issued and outstanding as of September 30, 2013 and December 31, 2012, respectively	910	841
Accumulated other comprehensive loss	(6)	(6)
Retained earnings	888	893
Total Portland General Electric Company shareholders' equity	1,792	1,728
Noncontrolling interests' equity	1	2
Total equity	**1,793**	**1,730**
Total liabilities and equity	**$ 5,891**	**$ 5,670**

See accompanying notes to condensed consolidated financial statements.

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

	Nine Months Ended September 30,	
	2013	**2012**
Cash flows from operating activities:		
Net income	$ 57	$ 112
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	186	188
Cascade Crossing transmission project	52	—
Pension and other postretirement benefits	28	22
Decrease in net liabilities from price risk management activities	(35)	(142)
Regulatory deferral—price risk management activities	35	140
Regulatory deferral of settled derivative instruments	13	1
Decoupling mechanism deferrals, net of amortization	(5)	1
Allowance for equity funds used during construction	(8)	(4)
Power cost deferrals, net of amortization	(4)	(4)
Deferred income taxes	(2)	70
Other non-cash income and expenses, net	18	15
Changes in working capital:		
Decrease in receivables	47	41
Decrease in margin deposits, net	10	27
Income tax refund received	—	8
Increase (decrease) in payables and accrued liabilities	13	(42)
Other working capital items, net	24	23
Proceeds received from Trojan spent fuel legal settlement	44	—
Other, net	(14)	(6)
Net cash provided by operating activities	**459**	**450**
Cash flows from investing activities:		
Capital expenditures	(453)	(218)
Proceeds from sale of solar power facility	—	10
Contribution to nuclear decommissioning trust	(44)	—
Sales of nuclear decommissioning trust securities	20	18
Purchases of nuclear decommissioning trust securities	(21)	(19)
Proceeds received from insurance recovery	3	—
Other, net	4	—
Net cash used in investing activities	**(491)**	**(209)**

See accompanying notes to condensed consolidated financial statements.

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

	Nine Months Ended September 30,	
	2013	**2012**
Cash flows from financing activities:		
Proceeds from issuance of long-term debt	$ 225	$ —
Payments on long-term debt	(100)	—
Proceeds from issuance of common stock, net of issuance costs	67	—
Borrowings on short-term debt	35	—
Payments on short-term debt	(35)	—
Maturities of commercial paper, net	(17)	(30)
Dividends paid	(62)	(61)
Debt issuance costs	(2)	—
Net cash provided by (used in) financing activities	**111**	**(91)**
Increase in cash and cash equivalents	79	150
Cash and cash equivalents, beginning of period	12	6
Cash and cash equivalents, end of period	**$ 91**	**$ 156**
Supplemental cash flow information is as follows:		
Cash paid for interest, net of amounts capitalized	$ 57	$ 61
Cash paid for income taxes	9	6
Non-cash investing and financing activities:		
Accrued dividends payable	22	21
Accrued capital additions	23	15
Preliminary engineering costs transferred to Construction work in progress from Other noncurrent assets	9	—

See accompanying notes to condensed consolidated financial statements.

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

NOTE 1: BASIS OF PRESENTATION

Nature of Business

Portland General Electric Company (PGE or the Company) is a single, vertically integrated electric utility engaged in the generation, transmission, distribution, and retail sale of electricity. 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 service area is located entirely within the state of Oregon. PGE's service area includes 52 incorporated cities, of which Portland and Salem are the largest, within a state-approved service area allocation of approximately 4,000 square miles. As of September 30, 2013, PGE served 835,540 retail customers with a service area population of approximately 1.7 million, comprising approximately 44% 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 footnote 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 2013 presentation, PGE has separately presented Decoupling mechanism deferrals, net of amortization of $1 million from Other non-cash income and expenses, net and collapsed Contribution to voluntary employees' beneficiary association trust of $2 million to Other, net and Renewable adjustment clause deferrals of $1 million to Other non-cash income and expenses, net, all of which are included in the operating activities section of the condensed consolidated statement of cash flows for the nine months ended September 30, 2012.

The financial information included herein for the three and nine month periods ended September 30, 2013 and 2012 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 results 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, 2012 is derived from the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2012, included in Item 8 of PGE's Annual Report on Form 10-K, filed with the SEC on February 22, 2013, and 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 or nine month periods ended September 30, 2013 and 2012.

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.

Customer Billing Matter

In May 2013, PGE discovered that it had over-billed an industrial customer during a period of several years as a result of a meter configuration error. An analysis of the data determined that the Company's revenues were overstated by approximately $3 million in 2012 and in 2011, $2 million in 2010, and $1 million in 2009. PGE believes the customer billing error is not material to any annual reporting period. The Company corrected this matter in the second quarter of 2013 as an out of period adjustment, and recorded, as a reduction to Revenues, net, a refund to the customer in the amount of $9 million.

Recent Accounting Pronouncements

Accounting Standards Update (ASU) 2011-11, *Balance Sheet (Topic 210) - Disclosures about Offsetting Assets and Liabilities* (ASU 2011-11), requires an entity to disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. In addition, ASU 2013-01, *Balance Sheet (Topic 210) - Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities* (ASU 2013-01), was issued in January 2013 and clarifies that the scope of ASU 2011-11 applies to financial instruments accounted for in accordance with Topic 815, *Derivatives and Hedging*. Both ASUs are effective January 1, 2013 for the Company, and require retrospective application. PGE adopted the amendments contained in ASU 2011-11 and ASU 2013-01 on January 1, 2013, which did not have an impact on the Company's consolidated financial position, consolidated results of operations, or consolidated cash flows. See Note 4, Price Risk Management, for the additional disclosures made pursuant to the adoption of these ASUs.

New Tax Regulation

On September 13, 2013, the U.S. Department of Treasury issued final regulations related to the deductibility and capitalization of expenditures on tangible property. The regulations give a general framework to distinguish capital expenditures from supplies, repairs, maintenance and other deductible business expenses that apply to amounts paid or incurred on or after January 1, 2014 with the option to early adopt for earlier tax periods. The U.S. Department of Treasury is expected to provide further guidance on the new regulations during the fourth quarter of 2013.

Based on an initial analysis, the Company does not believe that the new regulations have a material impact to the consolidated financial statements. PGE will complete a more detailed assessment in the fourth quarter of 2013 to determine the impact of each specific provision and evaluate potential options for the adoption of the new regulations. The impact, if any, would occur between balance sheet classification of current and noncurrent deferred tax balances and taxes currently payable, but would not impact income tax expense.

NOTE 2: BALANCE SHEET COMPONENTS

Accounts Receivable, Net

Accounts receivable is net of an allowance for uncollectible accounts of $5 million as of September 30, 2013 and December 31, 2012.

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

	Nine Months Ended September 30,	
	2013	2012
Balance as of beginning of period	$ 5	$ 6
Provision, net	4	6
Amounts written off, less recoveries	(4)	(6)
Balance as of end of period	$ 5	$ 6

Inventories

PGE inventories are recorded at average cost and 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.

Other Current Assets

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

	September 30, 2013	December 31, 2012
Prepaid expenses	$ 25	$ 37
Current deferred income tax asset	37	51
Assets from price risk management activities	1	4
Other	—	1
Other current assets	$ 63	$ 93

Electric Utility Plant, Net

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

	September 30, 2013	December 31, 2012
Electric utility plant	$ 6,975	$ 6,811
Construction work in progress	377	140
Total cost	7,352	6,951
Less: accumulated depreciation and amortization	(2,693)	(2,559)
Electric utility plant, net	$ 4,659	$ 4,392

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

As of December 31, 2012, Construction work in progress included $46 million related to the Cascade Crossing Transmission Project (Cascade Crossing), which was originally proposed as a 215-mile, 500 kV transmission project between Boardman, Oregon and Salem, Oregon. Based on subsequent analysis and an updated forecast of demand and future transmission capacity in the region, PGE determined in the second quarter of 2013 that the original projections of transmission capacity limitations contemplated in the Integrated Resource Plan (IRP) process were not likely to fully materialize. As a result, PGE and Bonneville Power Administration (BPA) worked toward refining the scope of the project and executed a non-binding memorandum of understanding (MOU) in May 2013. In connection with the MOU, the parties explored a new option under which BPA could provide PGE with ownership of approximately 1,500 MW of transmission capacity rights. As a result of the changed conditions reflected in the MOU, PGE also suspended permitting and development of Cascade Crossing and charged $52 million of capitalized costs related to Cascade Crossing to expense in the second quarter of 2013. Additionally, in June 2013, the Company filed with the Public Utility Commission of Oregon (OPUC) seeking deferral of these costs for future recovery in customer prices. In October 2013, the parties determined that they would not be able to reach an agreement on the financial terms for the proposed ownership of transmission capacity rights and, therefore, agreed to discontinue discussions on this option. The Company has determined that, under current conditions, the best option for meeting its transmission needs is to continue to acquire transmission service offered under BPA’s Open Access Transmission Tariff. In light of this development, the Company intends to withdraw the deferral application previously filed with the OPUC.

PGE completed construction of a $10 million, 1.75 MW solar powered electric generating facility, which was sold to, and simultaneously leased-back from, a financial institution in January 2012. The Company operates the facility and receives 100% of the power generated by the facility. This transaction is reflected as an investing activity in the condensed consolidated statement of cash flows for the nine months ended September 30, 2012.

Accumulated depreciation and amortization in the table above includes accumulated amortization related to intangible assets of $167 million and $151 million as of September 30, 2013 and December 31, 2012, respectively. Amortization expense related to intangible assets was $5 million for the three months ended September 30, 2013 and 2012, and $16 million and $17 million for the nine months ended September 30, 2013 and 2012, respectively.

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

Regulatory Assets and Liabilities

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

	September 30, 2013		December 31, 2012	
	Current	Noncurrent	Current	Noncurrent
Regulatory assets:				
Price risk management	$ 88	$ 71	$ 123	$ 71
Pension and other postretirement plans	—	301	—	321
Deferred income taxes	—	74	—	80
Deferred broker settlements	8	—	20	1
Debt reacquisition costs	—	18	—	22
Deferred capital projects	—	29	—	16
Other	3	11	1	13
Total regulatory assets	$ 99	$ 504	$ 144	$ 524
Regulatory liabilities:				
Asset retirement removal costs	$ —	$ 733	$ —	$ 692
Trojan decommissioning activities (1)	—	41	—	—
Asset retirement obligations	—	39	—	39
Other	4	39	12	34
Total regulatory liabilities	$ 4 (2)	$ 852	$ 12 (1)	$ 765

(1) During the third quarter of 2013, PGE received a settlement for the reimbursement of certain monitoring costs incurred related to spent nuclear fuel at the Company's Trojan nuclear power plant. See Complaint Against U.S. Department of Energy in Note 7, Contingencies, for additional information.
(2) Included in Accrued expenses and other current liabilities in the condensed consolidated balance sheets.

Accrued Expenses and Other Current Liabilities

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

	September 30, 2013	December 31, 2012
Accrued employee compensation and benefits	$ 44	$ 46
Accrued interest payable	33	23
Accrued taxes payable	35	21
Accrued dividends payable	22	21
Regulatory liabilities—current	4	12
Other	54	56
Total accrued expenses and other current liabilities	$ 192	$ 179

Credit Facilities

PGE has the following unsecured revolving credit facilities as of September 30, 2013:

- A $400 million syndicated credit facility, which is scheduled to terminate in November 2017; and
- A $300 million syndicated credit facility, which is scheduled to terminate in December 2016.

Pursuant to the individual terms of the agreements, both revolving credit facilities 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 applicable credit facility. Both revolving credit facilities require annual fees based on PGE’s unsecured credit ratings, and contain customary covenants and default provisions, including a requirement that limits consolidated indebtedness, as defined in the agreements, to 65% of total capitalization. As of September 30, 2013, PGE was in compliance with this requirement with a 49.6% debt to total capital ratio. The Company also has two letter of credit facilities under which it may obtain letters of credit in an aggregate amount not to exceed $51.5 million. In October 2013, one of the letter of credit facilities was increased from $21.5 million to $30 million, thereby increasing the total capacity under the letter of credit facilities to $60 million.

PGE 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 credit facilities.

Pursuant to an order issued by the Federal Energy Regulatory Commission (FERC), the Company is authorized to issue short-term debt up to $700 million through February 6, 2014. 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.

PGE classifies borrowings under the revolving credit facilities and outstanding commercial paper as Short-term debt on the condensed consolidated balance sheets. As of September 30, 2013, PGE had no borrowings or commercial paper outstanding, $56 million of letters of credit issued, and aggregate available capacity of $696 million under the credit facilities.

Long-term Debt

During the nine months ended September 30, 2013, PGE had the following long-term debt transactions:

- In August, the Company repaid $50 million of 5.625% Series First Mortgage Bonds (FMBs) in accordance with the scheduled maturity and issued $75 million of 4.47% Series FMBs due 2043, with interest due and payable semi-annually in February and August;
- In June, PGE issued $150 million of 4.47% Series FMBs due 2044, with interest due and payable semi-annually in June and December; and
- In April, the Company repaid $50 million of 4.45% Series FMBs in accordance with the scheduled maturity.

In October 2013, PGE entered into a bond purchase agreement with certain institutional buyers under which the Company agreed to sell to these buyers an aggregate principal amount of $155 million of FMBs in two tranches, with interest due and payable semi-annually. The first tranche of $105 million of 4.74% Series FMBs due 2042 is expected to be issued in November 2013, with the second tranche of $50 million of 4.84% Series FMBs due 2048 expected to be issued in December 2013.

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):

	Three Months Ended September 30,					
	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2013	2012	2013	2012	2013	2012
Service cost	$ 4	$ 3	$ 1	$ —	$ —	$ —
Interest cost	7	8	1	1	—	—
Expected return on plan assets	(10)	(10)	—	—	—	—
Amortization of prior service cost	—	—	—	1	—	—
Amortization of net actuarial loss	6	4	—	—	—	—
Net periodic benefit cost	$ 7	$ 5	$ 2	$ 2	$ —	$ —

	Nine Months Ended September 30,					
	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2013	2012	2013	2012	2013	2012
Service cost	$ 12	$ 9	$ 2	$ 1	$ —	$ —
Interest cost	23	24	3	3	1	1
Expected return on plan assets	(30)	(30)	(1)	—	—	—
Amortization of prior service cost	—	—	1	1	—	—
Amortization of net actuarial loss	18	12	—	—	—	—
Net periodic benefit cost	$ 23	$ 15	$ 5	$ 5	$ 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 September 30, 2013 and December 31, 2012, and then classifies these financial assets and liabilities based on a fair value hierarchy. The fair value hierarchy, which contains three broad classification levels, is used to prioritize the inputs to the valuation techniques used to measure fair value. The 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.

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

PGE recognizes any transfers between levels in the fair value hierarchy as of the end of the reporting period. Changes to market liquidity conditions, the availability of observable inputs, or changes in the economic structure of a security marketplace may require transfer of the securities between levels. There were no significant transfers between levels during the three and nine month periods ended September 30, 2013 and 2012.

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

	As of September 30, 2013			
	Level 1	Level 2	Level 3	Total
Assets:				
Nuclear decommissioning trust: [1]				
Money market funds	$ —	$ 59	$ —	$ 59
Debt securities:				
Domestic government	6	9	—	15
Corporate credit	—	8	—	8
Non-qualified benefit plan trust: [2]				
Equity securities—Domestic	5	3	—	8
Debt securities—Domestic government	1	—	—	1
Assets from price risk management activities [1] [3]—Natural gas	—	1	—	1
	$ 12	$ 80	$ —	$ 92
Liabilities from price risk management activities: [1] [3]				
Electricity	$ —	$ 39	$ 39	$ 78
Natural gas	—	57	25	82
	$ —	$ 96	$ 64	$ 160

(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 $25 million, which are recorded at cash surrender value.
(3) For further information, see Note 4, Price Risk Management.

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

	As of December 31, 2012			
	Level 1	Level 2	Level 3	Total
Assets:				
Nuclear decommissioning trust: [1]				
Money market funds	$ —	$ 15	$ —	$ 15
Debt securities:				
Domestic government	7	8	—	15
Corporate credit	—	8	—	8
Non-qualified benefit plan trust: [2]				
Money market funds	—	2	—	2
Equity securities:				
Domestic	2	2	—	4
International	1	—	—	1
Debt securities—Domestic government	2	—	—	2
Assets from price risk management activities: [1] [3]				
Electricity	—	1	—	1
Natural gas	—	3	2	5
	$ 12	$ 39	$ 2	$ 53
Liabilities — Liabilities from price risk management activities: [1] [3]				
Electricity	$ —	$ 72	$ 10	$ 82
Natural gas	—	110	8	118
	$ —	$ 182	$ 18	$ 200

(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 $23 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—Certain equity mutual fund and common stock securities are classified as Level 1 in the fair value hierarchy due to the availability of quoted prices for identical assets in an active market as of the reporting date. Principal markets for equity prices include published exchanges such as NASDAQ and the New York Stock Exchange (NYSE). 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 as of the reporting date.

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 exposure to commodity price risk and foreign currency exchange rate risk, and reduce volatility in net power costs 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 quoted forward prices for commodities and interest rates. Substantially all of these assumptions 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 over-the-counter forwards 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 over-the-counter swap derivatives.

Quantitative information regarding the significant, unobservable inputs used in the measurement of Level 3 assets and liabilities from price risk management activities as of September 30, 2013 is presented below:

Commodity Contracts	Fair Value: Assets	Fair Value: Liabilities	Valuation Technique	Significant Unobservable Input	Price per Unit: Low	Price per Unit: High	Price per Unit: Weighted Average
	(in millions)						
Natural gas financial swaps	$ —	$ 25	Discounted cash flow	Natural gas forward price (per Decatherm)	$ 3.22	$ 4.71	$ 3.87
Electricity financial swaps	—	13	Discounted cash flow	Electricity forward price (per MWh)	8.91	48.28	36.23
Electricity physical forward purchase	—	26	Discounted cash flow	Electricity forward price (per MWh)	8.11	50.49	32.67
	$ —	$ 64					

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(Unaudited)

Quantitative information regarding the significant, unobservable inputs used in the measurement of Level 3 assets and liabilities from price risk management activities as of December 31, 2012 is presented below:

Commodity Contracts	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Price per Unit Low	Price per Unit High	Price per Unit Weighted Average
	(in millions)						
Natural gas financial swaps	$ 2	$ 8	Discounted cash flow	Natural gas forward price (per Decatherm)	$ 3.67	$ 5.21	$ 4.28
Electricity financial swaps	—	10	Discounted cash flow	Electricity forward price (per MWh)	7.12	51.72	41.14
	$ 2	$ 18					

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. These inputs employ the mid-point of the market's bid-ask spread and are derived using observed transactions in active markets, as well as historical experience as a participant in those markets. These inputs are validated against nonbinding quotes from brokers with whom the Company transacts. 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's Risk Management group. 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 September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Balance as of the beginning of the period	$ 56	$ 88	$ 16	$ 79
Net realized and unrealized losses (gains) (1)	8	(7)	48	4
Purchases	—	(2)	—	(2)
Issuances	—	—	—	(1)
Transfers out of Level 3 to Level 2	—	—	—	(1)
Balance as of the end of the period	$ 64	$ 79	$ 64	$ 79

(1) Contains nominal amounts of realized (gains) and losses, net. 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 nine month periods ended September 30, 2013 and 2012, 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 long-term debt is classified as a Level 2 fair value measurement and is estimated based on the quoted market prices for similar issues or on the current rates offered to PGE for debt of similar remaining maturities. As of September 30, 2013, the estimated aggregate fair value of PGE's long-term debt was $1,927 million, compared to its $1,761 million carrying amount. As of December 31, 2012, the estimated aggregate fair value of PGE's long-term debt was $1,949 million, compared to its $1,636 million carrying amount.

NOTE 4: PRICE RISK MANAGEMENT

PGE participates in the wholesale marketplace in order to balance its supply of power, which consists of its own generation combined with wholesale market transactions, to meet the needs of its retail customers, manage risk, and administer its existing long-term wholesale contracts. Such activities include 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 net power costs 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 process authorized by the OPUC, PGE recognizes a regulatory asset or liability to defer the gains and losses from derivative instruments until realized. This accounting treatment defers the fair value gains and losses on 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 purely economic hedges. The Company does not engage in trading activities for non-retail purposes.

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

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

	September 30, 2013	December 31, 2012
Current assets:		
Commodity contracts:		
Electricity	$ —	$ 1
Natural gas	1	3
Total current derivative assets	1 (1)	4 (1)
Noncurrent assets:		
Commodity contracts—Natural gas	— (2)	2 (2)
Total derivative assets not designated as hedging instruments	$ 1	$ 6
Total derivative assets	$ 1	$ 6
Current liabilities:		
Commodity contracts:		
Electricity	$ 42	$ 44
Natural gas	47	83
Total current derivative liabilities	89	127
Noncurrent liabilities:		
Commodity contracts:		
Electricity	36	38
Natural gas	35	35
Total noncurrent derivative liabilities	71	73
Total derivative liabilities not designated as hedging instruments	$ 160	$ 200
Total derivative liabilities	$ 160	$ 200

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

PGE's net 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 2017, were as follows (in millions):

	September 30, 2013		December 31, 2012	
Commodity contracts:				
Electricity	12	MWh	11	MWh
Natural gas	104	Decatherms	86	Decatherms
Oil	(1)	Gallons	—	Gallons
Foreign currency	$ 7	Canadian	$ 7	Canadian

PGE has elected to report gross on the balance sheet the positive and negative exposures resulting from derivative instruments with counterparties under 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.

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

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: Derivatives	Gross Amounts Not Offset in Condensed Consolidated Balance Sheets: Cash Collateral[1]	Net Amount
As of September 30, 2013:						
Liabilities:						
Commodity contracts:						
Electricity[2]	$ 14	$ —	$ 14	$ (14)	$ —	$ —
Natural gas[2]	3	—	3	(3)	—	—
	$ 17	$ —	$ 17	$ (17)	$ —	$ —
As of December 31, 2012:						
Liabilities:						
Commodity contracts:						
Electricity[2]	$ 20	$ —	$ 20	$ (20)	$ —	$ —
Natural gas[2]	7	—	7	(7)	—	—
	$ 27	$ —	$ 27	$ (27)	$ —	$ —

(1) As of September 30, 2013 and December 31, 2012, the Company had collateral posted of $6 million and $18 million, respectively, which consists 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 (gains) losses 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 September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Commodity contracts:				
Electricity	$ (1)	$ (3)	$ 17	$ 40
Natural Gas	10	(19)	30	6

Net unrealized and certain net realized (gains) losses presented in the table above are offset within the condensed consolidated statements of income by the effects of regulatory accounting. Of the net (gains) losses recognized in Net income for the three months ended September 30, 2013 and 2012, net losses of $7 million and net gains of $30 million, respectively, have been offset, with net losses of $66 million and $14 million offset for the nine months ended September 30, 2013 and 2012, respectively.

Assuming no changes in market prices and interest rates, the following table indicates the year in which the net unrealized loss recorded as of September 30, 2013 related to PGE's derivative activities would become realized as a result of the settlement of the underlying derivative instrument (in millions):

	2013	2014	2015	2016	2017	Total
Commodity contracts:						
Electricity	$ 8	$ 40	$ 23	$ 7	$ —	$ 78
Natural gas	21	34	11	11	4	81
Net unrealized loss	$ 29	$ 74	$ 34	$ 18	$ 4	$ 159

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 all derivative instruments with credit-risk-related contingent features that were in a liability position as of September 30, 2013 was $138 million, for which PGE has posted $26 million in collateral, consisting entirely of letters of credit. If the credit-risk-related contingent features underlying these agreements were triggered at September 30, 2013, the cash requirement to either post as collateral or settle the instruments immediately would have been $138 million. As of September 30, 2013, PGE has posted an additional $36 million in cash collateral which is classified as Margin deposits on the Company's condensed consolidated balance sheet, for derivative instruments with no credit-risk related contingent features.

Counterparties representing 10% or more of Assets and Liabilities from price risk management activities as of September 30, 2013 or December 31, 2012 were as follows:

	September 30, 2013	December 31, 2012
Assets from price risk management activities:		
Counterparty A	21%	—%
Counterparty B	14	—
Counterparty C	11	—
Counterparty D	9	21
Counterparty E	4	11
Counterparty F	1	13
Counterparty G	—	10
	60%	55%
Liabilities from price risk management activities:		
Counterparty H	16%	—%
Counterparty I	14	24
Counterparty A	10	14
Counterparty E	10	8
Counterparty J	9	10
	59%	56%

See Note 3 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: (1) employee stock purchase plan shares; (2) unvested time-based and performance-based restricted stock units along with associated dividend equivalent rights; and (3) 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 has been met. For the three and nine month periods ended September 30, 2013 and 2012, unvested performance-based restricted stock units and associated dividend equivalent rights of 439,891 and 469,149, respectively, were excluded from the dilutive calculation because the performance goals had not been met.

Components of basic and diluted earnings per share were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	**2012**	**2013**	**2012**
Numerator (in millions):				
Net income attributable to Portland General Electric Company common shareholders	$ 31	$ 38	$ 58	$ 113
Denominator (in thousands):				
Weighted-average common shares outstanding—basic	77,637	75,528	76,401	75,486
Dilutive effect of potential common shares	693	13	302	14
Weighted-average common shares outstanding—diluted	78,330	75,541	76,703	75,500
Earnings per share—basic and diluted	$ 0.40	$ 0.50	$ 0.76	$ 1.49

Basic and diluted earnings per share amounts are calculated based on actual amounts rather than the rounded amounts presented in the table above and on the condensed consolidated statements of income. Accordingly, calculations using the rounded amounts presented for net income and weighted average shares outstanding may yield results that vary from the earnings per share amounts presented in the table above.

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NOTE 6: EQUITY

The activity in equity during the nine month periods ended September 30, 2013 and 2012 is as follows (dollars in millions):

	Portland General Electric Company Shareholders' Equity				
	Common Stock		Accumulated Other Comprehensive Loss	Retained Earnings	Noncontrolling Interests' Equity
	Shares	Amount			
Balances as of December 31, 2012	75,556,272	$ 841	$ (6)	$ 893	$ 2
Issuances of common stock, net of issuance costs of $3	2,365,000	67	—	—	—
Issuance of shares pursuant to equity-based plans	146,027	—	—	—	—
Stock-based compensation	—	2	—	—	—
Dividends declared	—	—	—	(63)	—
Net income (loss)	—	—	—	58	(1)
Balances as of September 30, 2013	78,067,299	$ 910	$ (6)	$ 888	$ 1
Balances as of December 31, 2011	75,362,956	$ 836	$ (6)	$ 833	$ 3
Issuance of shares pursuant to equity-based plans	171,430	—	—	—	—
Stock-based compensation	—	2	—	—	—
Dividends declared	—	—	—	(61)	—
Net income (loss)	—	—	—	113	(1)
Balances as of September 30, 2012	75,534,386	$ 838	$ (6)	$ 885	$ 2

On June 11, 2013, PGE entered into an EFSA in connection with a public offering of 11,100,000 shares of its common stock. The underwriters exercised their over-allotment option in full in connection with such public offering and on June 17, 2013, PGE issued an additional 1,665,000 shares of PGE common stock for $28.54 per share, net of the underwriters' discount, or net proceeds of $47 million. In August, the Company issued 700,000 shares for net proceeds of $20 million.

Pursuant to the terms of the EFSA, a forward counterparty borrowed 11,100,000 shares of PGE's common stock from third parties in the open market and sold the shares to a group of underwriters for $29.50 per share, less an underwriting discount equal to $0.96 per share. The underwriters then sold the shares in a public offering. PGE receives proceeds from the sale of common stock when the EFSA is physically settled (described below), and at that time PGE records the proceeds in equity.

Under the terms of the EFSA, PGE may elect to settle the equity forward transactions by means of: (1) physical; (2) cash; or (3) net share settlement, in whole or in part, at any time on or prior to June 11, 2015, except in specified circumstances or events that would require physical settlement. To the extent that the transactions are physically settled, PGE would be required to issue and deliver shares of PGE common stock to the forward counterparty at the then applicable forward sale price. The forward sale price was initially determined to be $29.50 per share at the time the EFSA was entered into, and the amount of cash to be received by PGE upon physical settlement of the EFSA is subject to certain adjustments in accordance with the terms of the EFSA.

The use of the EFSA substantially eliminates future equity market price risk by fixing the common stock offering sales price under the then existing market conditions, while mitigating immediate share dilution resulting from the offering by postponing the actual issuance of common stock until such funds are needed in accordance with the Company's capital requirements. The EFSA had no initial fair value since it was entered into at the then market price of the common stock. PGE concluded that the EFSA was an equity instrument and that it does not qualify as a derivative because the EFSA was indexed to the Company's stock. PGE anticipates settling the EFSA through physical settlement on or before June 11, 2015.

At September 30, 2013, the Company could have physically settled the EFSA by delivering 10,400,000 shares to the forward counterparty in exchange for cash of $291 million. In addition, at September 30, 2013, the Company could have elected to make a cash settlement by paying approximately $3 million, or a net share settlement by delivering approximately 100,037 shares of common stock. To the extent that PGE makes a cash or net share settlement, the Company would receive no additional proceeds from the public offering.

Prior to settlement, the potentially issuable shares pursuant to the EFSA will be 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 would be 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.

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 is 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

Regulatory Proceedings. 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 1998, the Oregon Court of Appeals upheld the OPUC's order authorizing PGE's recovery of the Trojan investment, but held that the OPUC did not have the authority to allow the Company to recover a return on the Trojan investment and remanded the case to the OPUC for reconsideration.

In 2000, PGE entered into agreements to settle the litigation related to recovery of, and return on, its investment in Trojan. The settlement, which was approved by the OPUC, allowed PGE to remove from its balance sheet the remaining investment in Trojan as of September 30, 2000, along with several largely offsetting regulatory liabilities. After offsetting the investment in Trojan with these liabilities, the remaining Trojan regulatory asset balance of approximately $5 million (after tax) was expensed. As a result of the settlement, PGE's investment in Trojan was no longer included in prices charged to customers, either through a return of or a return on that investment. The Utility Reform Project (URP) did not participate in the settlement and filed a complaint with the OPUC challenging the settlement agreements. In 2002, the OPUC issued an order (2002 Order) denying all of the URP's challenges. In 2007, following several appeals by various parties, the Oregon Court of Appeals issued an opinion that remanded the 2002 Order to the OPUC for reconsideration.

The OPUC then issued an order in 2008 (2008 Order) that required PGE to provide refunds, including interest from September 30, 2000, to customers who received service from the Company during the period from October 1, 2000 to September 30, 2001. The Company recorded a charge of $33.1 million in 2008 related to the refund and accrued additional interest expense on the liability until refunds to customers were completed in the first quarter of 2010. The URP and the plaintiffs in the class actions described below separately appealed the 2008 Order to the Oregon Court of Appeals. On February 6, 2013, the Oregon Court of Appeals issued an opinion that upheld the 2008 Order. On May 31, 2013, the Court of Appeals denied the appellants' request for reconsideration of the decision. On October 18, 2013, the Oregon Supreme Court granted plaintiffs' petition seeking review of the February 6, 2013 Oregon Court of Appeals decision. Oral argument is scheduled for March 4, 2014.

Class Actions. In two separate legal proceedings, lawsuits were filed in Marion County Circuit Court against PGE in 2003 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 2006, the Oregon Supreme Court issued a ruling ordering the abatement of the class action proceedings until the OPUC responded to the 2002 Order (described above). The Oregon Supreme Court concluded that the OPUC has primary jurisdiction to determine what, if any, remedy can 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. The Marion County Circuit Court subsequently abated the class actions in response to the ruling of the Oregon Supreme Court.

As noted above, on February 6, 2013, the Oregon Court of Appeals upheld the 2008 Order. Because the Oregon Supreme Court has granted the plaintiffs' petition seeking review of that decision, and the class actions described above remain pending, management believes that it is reasonably possible that the regulatory proceedings and class actions could result in a loss to the Company in excess of the amounts previously recorded and discussed above. Because these matters involve unsettled legal theories and have a broad range of potential outcomes, sufficient information is currently not available to determine PGE's potential liability, if any, or to estimate a range of potential loss.

Pacific Northwest Refund Proceeding

In 2001, the FERC called for a hearing to explore whether there may have been unjust and unreasonable charges for spot market sales of electricity in the Pacific Northwest from December 25, 2000 through June 20, 2001 (Pacific Northwest Refund proceeding). During that period, PGE both sold and purchased electricity in the Pacific Northwest. In 2003, the FERC issued an order terminating the proceeding and denying the claims for refunds. Parties appealed various aspects of the FERC order to the U.S. Ninth Circuit Court of Appeals (Ninth Circuit).

In August 2007, the Ninth Circuit issued a decision, concluding that the FERC failed to adequately explain how it considered or examined new evidence showing intentional market manipulation in California and its potential ties to the Pacific Northwest and that the FERC should not have excluded from the Pacific Northwest Refund proceeding purchases of energy made by the California Energy Resources Scheduling (CERS) division in the Pacific Northwest spot market. The Ninth Circuit remanded the case to the FERC to: i) address the new market manipulation evidence in detail and account for the evidence in any future orders regarding the award or denial of refunds in the proceedings; ii) include sales to CERS in its analysis; and iii) further consider its refund decision in light of related, intervening opinions of the court. The Ninth Circuit offered no opinion on the FERC's findings based on the record established by the administrative law judge and did not rule on the FERC's ultimate decision to deny refunds. After denying requests for rehearing, the Ninth Circuit in April 2009 issued a mandate giving immediate effect to its August 2007 order remanding the case to the FERC.

In October 2011, the FERC issued an Order on Remand, establishing an evidentiary hearing to determine whether any seller had engaged in unlawful market activity in the Pacific Northwest spot markets during the December 25, 2000 through June 20, 2001 period by violating specific contracts or tariffs, and, if so, whether a direct connection existed between the alleged unlawful conduct and the rate charged under the applicable contract. The FERC held 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 before a refund could be ordered. The FERC directed the presiding judge, if necessary, to determine a refund methodology and to calculate refunds, but held that a market-wide remedy was not appropriate, given the bilateral contract nature of the Pacific Northwest spot markets. Certain parties claiming refunds filed requests for rehearing of the Order on Remand.

In December 2012, the FERC issued an order granting an interlocutory appeal of the trial judge's ruling on the scope of the remand proceeding. In this order, the FERC held that its Order on Remand was not intended to alter the general state of the law regarding the *Mobile-Sierra* presumption. The FERC clarified that the *Mobile-Sierra* presumption could be 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.

On April 5, 2013, and subject to its December 2012 clarification in the interlocutory appeal, the FERC denied rehearing requests from refund proponents that had contested the FERC's use of the *Mobile-Sierra* standard in the remand proceeding, its denial of a market-wide remedy, and the restraints in the Order on Remand that limited the types of evidence that could be introduced in the hearing. However, the FERC granted rehearing on the issue of the appropriate refund period, holding that parties could pursue refunds for transactions between January 1, 2000 and December 24, 2000 under Section 309 of the Federal Power Act by showing violations of a filed tariff or rate schedule or of a statutory requirement. Refund claimants have filed petitions for appeal of the Order on Remand and the Order on Rehearing with the Ninth Circuit.

In its October 2011 Order on Remand, the FERC ordered settlement discussions to be convened before a FERC settlement judge. Pursuant to the settlement proceedings, the Company received notice of two claims and reached agreements to settle both claims for an immaterial amount. The FERC approved both settlements during 2012.

Additionally, the settlement between PGE and certain other parties in the California refund case in Docket No. EL00-95, et seq., approved by the FERC in May 2007, resolved all claims between PGE and the California parties named in the settlement (including CERS) as to transactions in the Pacific Northwest during the settlement period, January 1, 2000 through June 20, 2001, but did not settle potential claims from other market participants relating to transactions in the Pacific Northwest.

The above-referenced settlements resulted in a release for the Company as a named respondent in the ongoing remand proceedings, which are limited to initial and direct claims for refunds, but there remains a possibility that additional claims related to this matter could be asserted against the Company in future proceedings if refunds are ordered against current respondents.

Management believes that this matter could result in a loss to the Company in future proceedings. However, management cannot predict whether the FERC will order refunds, which contracts would be subject to refunds, the basis on which refunds would be ordered, or how such refunds, if any, would be calculated. 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

A 1997 investigation by the United States Environmental Protection Agency (EPA) of a segment of the Willamette River known as Portland Harbor revealed significant contamination of river sediments. The EPA subsequently included Portland Harbor on the National Priority List pursuant to the federal Comprehensive Environmental Response, Compensation, and Liability Act (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 January 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 is currently undergoing 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 March 2012, the LWG submitted a draft FS to the EPA for review and approval. The draft FS, along with the RI, 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 expected to issue in 2015 or 2016.

The draft FS evaluates several alternative clean-up approaches. These approaches 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 January of 2010, the DEQ issued an order requiring PGE to perform an investigation of certain portions of the Downtown Reach. PGE completed this investigation in December 2011 and entered into a consent order with the DEQ in July 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. It is expected that a draft feasibility study report, which would provide a range of potential cost estimates, will be available by the end of 2013 or early 2014.

Management believes that it is reasonably possible that this matter could result in a loss to the Company. However, because the feasibility study continues, sufficient information is currently not available to determine PGE's liability for the cost of any required investigation or remediation of the Downtown Reach site or to estimate a range of potential loss.

Alleged Violation of Environmental Regulations at Colstrip

On July 30, 2012, PGE received a Notice of Intent to Sue (Notice) for violations of the Clean Air Act (CAA) at Colstrip Steam Electric Station (Colstrip) from counsel on behalf of the Sierra Club and the Montana Environmental Information Center (MEIC). The Notice was also addressed to the other Colstrip co-owners, including PPL Montana, LLC, the operator of Colstrip. PGE has a 20% ownership interest in Units 3 and 4 of Colstrip. The Notice alleges certain violations of the CAA, including New Source Review, Title V, and opacity requirements, and states that the Sierra Club and MEIC will: 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 Colstrip 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 Colstrip 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 Colstrip 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. On May 3, 2013, the defendants filed a motion to dismiss 36 of the 39 claims in the suit. On September 27, 2013, the plaintiffs filed an amended complaint that deleted the 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. This matter is scheduled for trial in October 2014.

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.

Challenge to AOC Related to Colstrip Wastewater Facilities

In August 2012, the operator of Colstrip entered into an AOC with the MDEQ, which established a comprehensive process to investigate and remediate groundwater seepage impacts related to the wastewater facilities at Colstrip. Within five years, under this AOC, the operator of Colstrip is required to provide financial assurance to MDEQ for the costs associated with closure of the waste water treatment facilities. This will establish an obligation for asset retirement, but the operator of Colstrip is unable at this time to estimate these costs, which will require both public and agency review.

In September 2012, Earthjustice filed an affidavit pursuant to Montana's Major Facility Siting Act (MFSA) that sought review of the AOC by Montana's Board of Environmental Review (BER), on behalf of environmental groups Sierra Club, the MEIC, and the National Wildlife Federation. In September 2012, the operator of Colstrip filed an election with the BER to have this proceeding conducted in Montana state district court as contemplated by the MFSA. In October 2012, Earthjustice, on behalf of Sierra Club, the MEIC and the National Wildlife Federation, filed with the Montana state district court a petition for a writ of mandamus and a complaint for declaratory relief alleging that the AOC fails to require the necessary actions under the MFSA and the Montana Water Quality Act with respect to groundwater seepage from the wastewater facilities at Colstrip. On May 31, 2013, the district court judge granted the defendants' motion to dismiss the petition for the writ of mandamus.

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.

Oregon Tax Court Ruling

On September 17, 2012, the Oregon Tax Court issued a ruling contrary to an Oregon Department of Revenue (DOR) interpretation and a current Oregon administrative rule, regarding the treatment of wholesale electricity sales. The underlying issue is whether electricity should be treated as tangible or intangible property for state income tax apportionment purposes. The DOR has appealed the ruling of the Oregon Tax Court to the Oregon Supreme Court. It is uncertain whether the ruling will be upheld.

If the ruling is upheld, PGE estimates that its income tax liability could increase by as much as $7 million due to an increase in the tax rate at which deferred tax liabilities would be recognized in future years. For open tax years per Oregon statute, 2008 through 2012, the Company entered into a closing agreement with the DOR during the third quarter 2013 under which the DOR agreed to the tax apportionment methodology utilized on the tax returns relating to those years. PGE cannot predict the outcome of this matter.

Complaint Against U.S. Department of Energy

In 2004, the co-owners of Trojan (PGE, Eugene Water & Electric Board, and PacifiCorp, collectively referred to as Plaintiffs) filed a complaint against the U.S. Department of Energy (USDOE) for failure to accept spent nuclear fuel by January 31, 1998. PGE had contracted with the USDOE for the permanent disposal of spent nuclear fuel in order to allow the final decommissioning of Trojan. The Plaintiffs paid for permanent disposal services during the period of plant operation and have met all other conditions precedent. The Plaintiffs were seeking approximately $112 million in damages incurred through 2009.

A trial before the U.S. Court of Federal Claims concluded in early 2012. On November 30, 2012, the U.S. Court of Federal Claims issued a judgment awarding certain damages to the Plaintiffs. The judgment did not state the precise amount of the damages award, but directed the parties to consult and propose a final amount for the Plaintiffs' recovery that was based on certain adjustments specified in the court's ruling. In July 2013, the parties reached a settlement wherein the Trojan co-owners were to receive $70 million for the period through 2009. PGE's share, approximately $44 million, was received during the third quarter 2013 and deposited into the Nuclear Decommissioning Trust. The settlement agreement also provided for a process to submit claims for allowable costs for the period 2010 through 2013. Recovery of any costs for periods after 2013 will be covered in subsequent agreements. The proceeds received related to this legal matter will flow to the benefit of customers in future regulatory proceedings to offset amounts previously collected from customers in relation to Trojan decommissioning activities.

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 will not have a material impact on its financial position, results of operations, or cash flows, these matters are subject to inherent uncertainties, and management's view of these matters may change in the future.

NOTE 8: GUARANTEES

PGE enters into financial agreements and power and natural gas purchase and sale agreements that include indemnification provisions relating to certain claims or liabilities that may arise relating to the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnifications cannot be reasonably estimated. PGE periodically evaluates the likelihood of incurring costs under such indemnities based on the Company's historical experience and the evaluation of the specific indemnities. As of September 30, 2013, 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.

NOTE 9: VARIABLE INTEREST ENTITIES

PGE has determined that it is the primary beneficiary of three variable interest entities (VIEs) and, therefore, consolidates the VIEs within the Company's condensed consolidated financial statements. All three arrangements were formed for the sole purpose of designing, developing, constructing, owning, maintaining, operating, and financing photovoltaic solar power facilities located on real property owned by third parties, and selling the energy generated by the facilities. PGE is the Managing Member in each of the Limited Liability Companies (LLCs), holding less than 1% equity interest in each entity, and a financial institution is the Investor Member, holding more than 99% equity interest in each entity. PGE has determined that its interests in these VIEs contain the obligation to absorb the variability of the entities that could potentially be significant to the VIEs, and the Company has the power to direct the activities that most significantly affect the entities' economic performance.

Determining whether PGE is the primary beneficiary of a VIE is complex, subjective, and requires the use of judgments and assumptions. Significant judgments and assumptions made by PGE in determining it is the primary beneficiary of these LLCs include the following: (i) PGE has the expertise to own and operate electric generating facilities and is authorized to operate the LLCs pursuant to the operating agreements, and, therefore, PGE has control over the most significant activities of the LLCs; (ii) PGE expects to own 100% of the LLCs shortly after five years have elapsed from when the facility was placed in service, at which time the facilities will have approximately 75% of their estimated useful life remaining; and (iii) based on projections prepared in accordance with the operating agreements, PGE expects to absorb a majority of any expected losses of the LLCs.

Included in PGE’s condensed consolidated balance sheets are LLC net assets of $5 million as of September 30, 2013, consisting of Electric utility plant, net, and $6 million as of December 31, 2012, consisting of Cash and cash equivalents of $1 million and Electric utility plant, net of $5 million. These assets can only be used to settle the obligations of the consolidated VIEs.

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 operations, business prospects, expected changes in 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 other data, 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;
- 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 Condensed Consolidated Financial Statements;
- the failure to complete capital projects on schedule and within budget or the abandonment of capital projects, which could result in the Company's inability to recover project costs;
- operational factors affecting PGE's power generation facilities, including forced outages, hydro and wind conditions, and disruption of fuel supply, which may cause the Company to incur repair costs, as well as increased power costs for replacement power;
- changes in wholesale prices for fuels, including natural gas, coal, and oil, and the impact of such changes on the Company's power costs;
- changes in the availability and price of wholesale power;
- 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;
- 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;
- volatility in wholesale power and natural gas prices, which could require the Company to issue additional letters of credit or post additional cash as collateral with counterparties pursuant to existing power and natural gas purchase agreements;

- future laws, regulations, and proceedings that could increase the Company's costs or affect the operations of the Company's thermal generating plants by imposing requirements for additional emissions controls or significant emissions fees or taxes, particularly with respect to coal-fired generation facilities, in order to mitigate carbon dioxide, mercury and other gas emissions;
- capital market conditions, including access to capital, interest rate volatility, reductions in demand for investment-grade commercial paper, as well as changes in PGE's credit ratings, 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 repayments of maturing debt;
- 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 debt and equity securities held for the defined benefit pension plans and other benefit plans, which could result in increased funding requirements for such plans;
- changes in, and compliance with, environmental and endangered species laws and policies;
- the effects of climate change, including changes in the environment, which may affect energy costs or consumption, increase the Company's costs, or adversely affect its operations;
- new federal, state, and local laws that could have adverse effects on operating results;
- 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 a significant number of employees approaching retirement, potential strikes, work stoppages, and transitions in senior management;
- political, economic, and financial market conditions;
- natural disasters and other risks, such as earthquakes, floods, droughts, lightning, wind, and fire;
- 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, nor can it 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, 2012, and other periodic and current reports filed with the SEC.

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 affect on revenues while the availability and price of purchased power and fuel can affect income from operations.

Customers and Demand—Retail energy deliveries for the nine months ended September 30, 2013 decreased 0.4% from the comparable period of 2012, which can largely be attributed to the nine months ended September 30, 2013 having one less day in the period due to the leap year in 2012. The decline was partially offset by an increase of 5,300 in the average number of total retail customers served. Energy efficiency and conservation efforts by retail customers continue to influence total deliveries, although the financial impacts to the Company of such efforts are intended to be mitigated by the decoupling mechanism.

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

	Nine Months Ended September 30,				
	2013		2012		% Increase /(Decrease)in Energy Deliveries
	Average Number of Customers	Retail Energy Deliveries*	Average Number of Customers	Retail Energy Deliveries*	
Residential	727,579	5,469	722,884	5,506	(0.7)%
Commercial	104,436	5,540	103,798	5,566	(0.5)
Industrial	264	3,186	261	3,180	0.2
Total	832,279	14,195	826,943	14,252	(0.4)

* In thousands of MWh.

On a weather adjusted basis, total retail energy deliveries for the nine months ended September 30, 2013 were comparable to the same period of 2012. Removing the effect of the leap year, the weather adjusted deliveries are slightly higher than the prior period due to a modest increase in industrial deliveries and the addition of residential customers. Net of the effects of energy efficiency and conservation efforts, PGE expects retail energy deliveries for 2013 to be comparable to weather adjusted 2012 levels.

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. During the nine months ended September 30, 2013 and 2012, availability of the plants PGE operates approximated 90% and 93%, respectively, with the availability of Colstrip Units 3 and 4, in which PGE has a 20% ownership interest but does not operate, approximating 66% and 92% for the same periods, respectively.

During the third quarter of 2013, PGE experienced unplanned forced outages at three of its generating plants as follows:

- Colstrip Unit 4 coal-fired generating plant tripped off-line on July 1, 2013 as a result of damage that occurred in the unit's generator. PGE has a 20% ownership interest in Colstrip Unit 4, which is operated by PPL Montana, LLC. The Company's share of the net capacity of the plant is 148 MW. The total repair costs are estimated to range from $30 million to $35 million, the majority of which are expected to be capitalized. The plant is expected to be back online in the first quarter of 2014. PPL Montana is working with the insurance carrier for reimbursement of the repair costs related to this event, which is subject to a $2.5 million deductible.

- Boardman coal-fired generating plant tripped off-line on July 1, 2013 as a result of a thermal water hammer event causing structural damage to the cold reheat piping line that runs between the turbine and the boiler. The Company has a 65% ownership interest in Boardman, which is operated by PGE. The Company's share of the net capacity of the plant is 374 MW. The plant came back online July 31, 2013, with total repair costs approximating $10 million, the majority of which have been capitalized, net of insurance proceeds. Property damage insurance for the Boardman repair costs is subject to a $2.5 million deductible and, as of September 30, 2013, total insurance proceeds received were approximately $5 million, of which $3 million was PGE's share.

- Coyote Springs natural gas-fired generating plant has been off-line since August 24, 2013 as a result of cracks in the steam turbine rotor. Coyote Springs has a net capacity of 246 MW, which represents approximately 9% of the Company's total net generating capacity. PGE estimates the repair costs to approximate $2 million and to be included in operating and maintenance expense, with any potential insurance recovery subject to a $2.5 million deductible for each event. The repairs are expected to be completed and the plant back online by the end of November 2013.

As a result of these unplanned outages, the Company will also incur incremental power costs to replace its share of the output of these plants over the period of time the plants are off-line. PGE estimates total incremental replacement power costs related to these unplanned plant outages to range from $16 million to $18 million for 2013, with approximately $11 million incurred during the third quarter of 2013. These incremental replacement power costs will be included in actual net variable power costs (NVPC) in the Company's power cost adjustment mechanism (PCAM) calculation for 2013.

During the nine months ended September 30, 2013, the Company's generating plants provided approximately 54% of its retail load requirement, compared with 47% in the nine months ended September 30, 2012. The increase in the proportion of power generated to meet the Company's retail load requirement was largely the result of the difference in the economic dispatch decisions made throughout the respective periods. Despite the unplanned plant outages, the proportion of power provided by the Company's generating plants in 2013 increased from 2012 because a greater amount of thermal generation was economically displaced in 2012 by lower-cost purchased power and increased energy from hydro resources, both of which were driven by more favorable hydro conditions.

Energy received from PGE-owned hydroelectric plants and under contracts from mid-Columbia hydroelectric projects decreased 11% in the nine months ended September 30, 2013 compared with the nine months ended September 30, 2012. These resources provided approximately 18% of the Company's retail load requirement for the nine months ended September 30, 2013, compared with 20% for the nine months ended September 30, 2012. Through September, energy received from these sources exceeded projections included in the Company's Annual Power Cost Update Tariff (AUT) by approximately 2% during 2013, compared with 12% during 2012. Such projections, which are finalized with the OPUC in November each year, establish the power cost component of retail prices for the following calendar year and are based, in part, on average regional hydro conditions. Any excess in hydro generation from that projected in the AUT generally displaces power from higher cost sources, while any shortfall is generally replaced with power from higher cost sources. Energy from hydro resources is expected to approximate projections included in the AUT for 2013.

Energy expected to be received from PGE-owned wind generating resources (Biglow Canyon) is projected annually in the AUT and is based on wind studies completed in connection with the permitting of the wind farm. Any excess in wind generation from that projected in the AUT generally displaces power from higher cost sources, while any shortfall is generally replaced with power from higher cost sources. Energy received from Biglow Canyon fell short of that projected in PGE's AUT by 14% and 17% in the nine months ended September 30, 2013 and 2012, respectively, and provided approximately 7% of the Company's retail load requirement for both periods.

Pursuant to the Company's PCAM, customer prices can be adjusted to reflect a portion of the difference between each year's forecasted 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. NVPC is classified as Purchased power and fuel in the Company's condensed consolidated statements of income, and is net of wholesale sales, 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 of 10%, 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 nine months ended September 30, 2013, actual NVPC was approximately $5 million below baseline NVPC. Based on forecast data, NVPC for the year ending December 31, 2013 is currently estimated to be above the baseline NVPC, but within the deadband range; accordingly, no estimated collection from or refund to customers is expected for 2013. As discussed previously, replacement power costs related to the unplanned outages of Boardman, Coyote Springs and Colstrip Unit 4 will be included in the Company's PCAM calculation for 2013.

For the nine months ended September 30, 2012, actual NVPC was approximately $14 million below baseline NVPC. For the full year 2012, actual NVPC was $17 million below baseline NVPC, and $2 million below the lower deadband threshold, resulting in a potential refund due to customers. However, based on results of the regulated earnings test, no estimated refund to customers was recorded for 2012.

Transmission Capacity—In May 2013, PGE and Bonneville Power Administration (BPA) executed a non-binding memorandum of understanding (MOU), under which the parties explored a transmission capacity option whereby BPA could provide PGE with ownership of approximately 1,500 MW of transmission capacity rights in exchange for certain PGE assets, investments and/or PGE transfer capabilities to BPA. As a result of the changed conditions reflected in the MOU, PGE suspended permitting and development of the Cascade Crossing transmission project (Cascade Crossing) and charged $52 million of capitalized costs related to Cascade Crossing to expense in the second quarter of 2013. Additionally, in June 2013, the Company filed with the OPUC seeking deferral of these costs for future recovery in customer prices. In October 2013, the parties determined that they would not be able to reach an agreement on the financial terms for the proposed ownership of transmission capacity rights and, therefore, agreed to discontinue discussions on this option. The Company has determined that, under current conditions, the best option for meeting its transmission needs is to continue to acquire transmission service offered under BPA's Open Access Transmission Tariff. In light of this development, the Company intends to withdraw the deferral application previously filed with the OPUC.

General Rate Case—In February 2013, PGE filed with the OPUC a general rate case based on a 2014 test year (2014 GRC). PGE's initial filing proposed a $105 million increase in annual revenues, representing an approximate 6% overall increase in customer prices. The initial filing also included a proposed capital structure of 50% debt and 50% equity, a return on equity of 10%, a cost of capital of 7.86%, and an average rate base of approximately $3.1 billion.

PGE, OPUC staff, and certain customer groups have reached agreements that resolve all revenue requirement matters in the case, subject to OPUC approval. The stipulated items, along with recently filed updates of power costs and forecasted load, resulted in a revised increase of $67 million in annual revenue requirement, as illustrated in the table below. The revised revenue requirement increase represents an approximate 4% overall increase in customer prices.

General Rate Case*

Annual revenue requirement change

($ in millions)

Increase to annual revenues—Initial filing	$	105
Reduction resulting from non-power cost stipulation		(42)
Increase resulting from update to load forecast (revenue)		15
Reduction resulting from power costs stipulation and updated power costs		(11)
Increase to annual revenues—As revised	$	67

* Forecasted 2014 NVPC and the split between cost-of-service and direct access load pursuant to the September opt-out window will be updated at various dates through November 15, 2013. These updates may change the amounts presented above.

The stipulated items, as filed with the OPUC in 2013, reflect the following:

- A capital structure of 50% debt and 50% equity;
- A return on equity of 9.75%;
- A cost of capital of 7.65%, reflecting actual 2013 debt issuances;
- An average rate base of $3.1 billion;
- Updates to incorporate revised information regarding expected 2014 costs;
- Allowance for PGE to collect approximately $16.5 million of certain 2014 information technology and customer service costs during a five year amortization period beginning in 2014, with rate base treatment of the uncollected balances;
- Implementation of a historical rolling average for forecasted wind generation;
- Extension of PGE’s decoupling mechanism for three years through 2016; and
- Updates to incorporate revised terms and conditions for the Company’s direct access program and streetlight pricing.

Regulatory review of the 2014 GRC will continue throughout 2013, with a final order expected to be issued by the OPUC in mid-December 2013. New customer prices are expected to become effective January 1, 2014.

Capital Requirements and Financing—In accordance with PGE's Integrated Resource Plan (IRP) and pursuant to the OPUC's competitive bidding guidelines, the Company issued two request for proposals (RFPs) during 2012 for additional generation resources—one for capacity and energy (baseload) resources, and one for renewable resources. PGE has completed the resource selections pursuant to the RFPs as follows:

> *Capacity and Energy (Baseload) Resources*—In January 2013, PGE's proposed Port Westward Unit 2 (PW2) flexible 220 MW generating resource was selected as the successful bid for the capacity resource. PW2, for which construction began during the second quarter of 2013, is expected to be in service in the first quarter of 2015 at an estimated cost of $300 million, excluding the Allowance for funds used during construction (AFDC). As of September 30, 2013, $107 million is included in Construction work in progress (CWIP) for PW2.
>
> In June 2013, a proposed 440 MW natural gas-fired power plant in eastern Oregon, located adjacent to the Company's Boardman plant, was selected as the successful bid for the energy (baseload) resource. The new facility, to be known as the Carty Generating Station (Carty), will be constructed by a third party and owned and operated by PGE. Carty is expected to be in service in 2016 at an estimated cost of $450 million, excluding AFDC. As of September 30, 2013, $62 million is included in CWIP for Carty.
>
> PGE has also entered into two power purchase agreements for up to 100 MW of seasonal peaking capacity. One agreement covers winter from December 2014 to February 2019 and the second agreement covers summer from July 2014 to September 2018. These power purchase agreements substantially complete the resource selections pursuant to the capacity and energy resources RFP.
>
> *Renewable Resources*—In June 2013, a new wind farm then under development in southeastern Washington was selected as the successful bid for the renewable resource. The closing of the asset purchase agreement, under which the Company acquired the development rights to the project occurred August 1, 2013. The new wind farm, to be known as Tucannon River Wind Farm (Tucannon River), is currently under construction by a third party and will be owned and operated by PGE upon completion. Tucannon River, with a nameplate capacity of 267 MW, consisting of 116 turbines each with a generating capacity of 2.3 MWs, is expected to be in service in the first half of 2015 at an estimated cost of $500 million, excluding AFDC. As of September 30, 2013, $63 million is included in CWIP for Tucannon River.

PGE's capital requirements are expected to approximate $720 million in 2013, which includes $400 million for the resources selected pursuant to the RFPs discussed above.

PGE expects to fund 2013 estimated capital requirements and contractual maturities of $100 million of long-term debt with cash from operations and proceeds from issuances of common stock and First Mortgage Bonds (FMBs). For additional information regarding the equity and debt transactions, see Note 6, Equity, and Note 2, Balance Sheet Components, respectively, in the Notes to Condensed Consolidated Financial Statements.

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

- Challenges to recovery of the Company's investment in its closed Trojan plant;
- Claims for refunds related to wholesale energy sales during 2000 - 2001 in the Pacific Northwest; 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.

The following discussion highlights certain regulatory items that have impacted the Company's revenues, results of operations, or cash flows for the nine months ended September 30, 2013 compared to the nine months ended

September 30, 2012 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. The OPUC issued an order on the 2013 AUT resulting in an estimated 2% decrease in customer prices as a result of expected lower power costs. The new prices became effective January 1, 2013 and are expected to result in a decrease of approximately $36 million in annual revenues when compared to revenues resulting from prices in effect for 2012. As part of its 2014 General Rate Case, PGE included projected power costs in its initial request for a $105 million increase in revenues. The power cost portion of the request was moved to a separate docket at the OPUC and has been agreed to by intervenors and the OPUC staff, subject to updates through November 15, 2013.

  In June 2013, the Company submitted the results of the PCAM for 2012 to the OPUC for final regulatory review and determination of any customer refund or collection. Based on a regulated earnings test, the PCAM for 2012 did not produce an anticipated refund to or collection from customers. PGE, the OPUC Staff, and other parties reached agreement that confirmed that no refunds or collections would be required, and in October 2013, the OPUC issued an order approving such agreement. In 2012, the Company submitted to the OPUC the results of its PCAM for 2011 based on a regulated earnings test, which resulted in a refund to customers of $6 million. The OPUC issued an order approving the refund, with the impact to customer prices effective January 1, 2013. For further information, see "*Power Operations*," within the Operating Activities section of this Overview, above.

- Renewable Resource Costs—Pursuant to a 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 2012, PGE submitted a filing for the installation of a small solar facility, which requested a nominal credit to customer prices for a one-year period beginning January 1, 2013, resulting from the gain on the sale and lease-back transaction directly related to the project.

  PGE did not submit a RAC filing to the OPUC in 2013 as it is not anticipated that the Company will place renewable resources into service during 2013. The Company may utilize the RAC to recover costs associated with its latest announced renewable resource, Tucannon River.

- Decoupling—The decoupling mechanism, which currently expires at the end of 2013, is intended to provide for recovery of margin lost as a result of any reduction in electricity sales attributable to energy efficiency and conservation efforts by residential and certain commercial customers. The Company requested in its 2014 GRC filing that the OPUC extend authorization of the mechanism to continue on a permanent basis. Agreements reached in the rate case, subject to OPUC approval, provide for continuation of the mechanism through 2016. The mechanism provides for collection from (or refund to) customers if weather adjusted use per customer is less (or more) than the levels projected in the Company's most recent approved general rate case.

  For the nine months ended September 30, 2013, the Company has recorded an estimated collection of $3 million. Any resulting collection from, or refund to, customers for the 2013 year would begin January 1, 2015.

  OPUC review of the annual filing for 2012 resulted in a collection of approximately $1 million, which began June 1, 2013 for a one year period.

During 2011, PGE recorded an estimated refund of $2 million that was provided to customers over a one year period that ended May 31, 2013, as weather adjusted use per customer was greater than projected levels.

- Capital deferral—In the 2011 General Rate Case, the OPUC authorized the Company to defer the costs associated with four capital projects that were not completed at the time the 2011 General Rate Case was approved. A regulatory asset of $15 million was recorded in 2012, for potential recovery in customer prices, subject to an earnings test, with an offsetting credit to Depreciation and amortization expense. The Company submitted a filing to the OPUC in July 2013 requesting recovery of the deferral over a one year period, with a resulting tariff effective January 1, 2014. For the nine months ended September 30, 2013, the Company deferred an additional $13 million of costs associated with these projects.

Integrated Resource Plan—PGE's IRP outlines how the Company will meet future customer demand and describes PGE's future energy supply strategy, reflecting new technologies, market conditions, and regulatory requirements. The Company's most recent IRP was acknowledged by the OPUC in November 2010. Based on an order received from the OPUC in October 2013, PGE is required to file its next IRP by March 30, 2014. The IRP will include projected future energy requirements and an action plan to meet such requirements, including long-term expectations for resource needs and portfolio performance.

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, 2012, filed with the SEC on February 22, 2013.

Results of Operations

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

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2013		2012		2013		2012	
Revenues, net	$ 435	100%	$ 450	100 %	$ 1,311	100 %	$ 1,342	100 %
Purchased power and fuel	190	44	182	40	538	41	533	40
Gross margin	245	56	268	60	773	59	809	60
Other operating expenses:								
Production and distribution	54	12	49	11	169	13	153	11
Cascade Crossing transmission project	—	—	—	—	52	4	—	—
Administrative and other	49	12	50	11	158	12	160	12
Depreciation and amortization	62	14	63	14	186	14	188	14
Taxes other than income taxes	27	6	24	6	79	6	77	6
Total other operating expenses	192	44	186	42	644	49	578	43
Income from operations	53	12	82	18	129	10	231	17
Interest expense	25	6	27	6	75	6	82	6
Other income, net	7	2	1	—	13	1	6	—
Income before income tax expense	35	8	56	12	67	5	155	11
Income tax expense	4	1	19	4	10	1	43	3
Net income	31	7	37	8	57	4	112	8
Less: net loss attributable to noncontrolling interests	—	—	(1)	—	(1)	—	(1)	—
Net income attributable to Portland General Electric Company	$ 31	7%	$ 38	8 %	$ 58	4 %	$ 113	8 %

Net income attributable to Portland General Electric Company was $31 million, or $0.40 per diluted share, for the third quarter of 2013, compared with $38 million, or $0.50 per diluted share, for the third quarter of 2012. The decrease in Net income is largely due to an increase in the average variable power cost, primarily due to unplanned plant outages combined with less energy received from hydro resources, which was partially offset by a decrease in the Company’s effective tax rate.

Net income attributable to Portland General Electric Company for the nine months ended September 30, 2013 was $58 million, or $0.76 per diluted share, compared with $113 million, or $1.49 per diluted share, for the nine months ended September 30, 2012. The decrease in Net income is largely due to the charge to expense of $52 million of capitalized costs related to Cascade Crossing and an industrial customer refund of $9 million related to cumulative over-billings over a period of several years. These two items are the primary drivers for the reduction in the Company’s effective tax rate for 2013, which has a favorable impact to net income when compared to 2012. In addition, an increase in the average variable power cost and higher operating and maintenance costs related to PGE’s transmission and distribution system contributed to the decrease in net income. Lower interest expense, an increase in the allowance for debt and equity funds used for construction, and higher earnings on the Non-qualified benefit plan trust assets partially offset the decreases to net income.

Three Months Ended September 30, 2013 Compared with the Three Months Ended September 30, 2012

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

	Three Months Ended September 30,			
	2013		2012	
Revenues [(1)] (dollars in millions):				
Retail:				
Residential	$ 186	43%	$ 187	42%
Commercial	162	37	168	37
Industrial	55	13	57	13
Subtotal	403	93	412	92
Other retail revenues, net	—	—	10	2
Total retail revenues	403	93	422	94
Wholesale revenues	22	5	19	4
Other operating revenues	10	2	9	2
Total revenues	$ 435	100%	$ 450	100%
Energy deliveries [(2)] (MWh in thousands):				
Retail:				
Residential	1,660	31%	1,626	30%
Commercial	1,957	37	1,963	36
Industrial	1,098	21	1,096	20
Total retail energy deliveries	4,715	89	4,685	86
Wholesale energy deliveries	581	11	771	14
Total energy deliveries	5,296	100%	5,456	100%
Average number of retail customers:				
Residential	728,816	87%	723,569	87%
Commercial	105,708	13	105,100	13
Industrial	259	—	259	—
Total	834,783	100%	828,928	100%

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

Total revenues decreased $15 million, or 3%, for the third quarter of 2013 compared with the third quarter of 2012 primarily as a result of the items described below.

Retail revenues are generated by the sale and delivery of energy to retail customers as well as from the delivery of energy that certain commercial and industrial customers purchase directly from ESSs. Retail revenues also include certain deferred revenues, primarily related to the PCAM and decoupling mechanisms. Retail revenues decreased $19 million, or 5%, in the third quarter of 2013 compared with the third quarter of 2012, resulting from the combination of the following items:

- An $11 million decrease resulting from lower average prices due primarily to the reduction in power costs as forecasted in the Company's 2013 AUT and a slightly larger portion of energy deliveries going to customers who purchase their energy from ESSs;

- A $7 million decrease related to the Company's PCAM, as the potential refund to customers related to the 2011 PCAM was reduced in the third quarter of 2012 as a result of the final OPUC review, with no estimated refund to or collection from customers recorded in the third quarter of 2013;
- A $3 million decrease related to the decoupling mechanism, with a $1 million potential refund recorded in the third quarter of 2013 compared with a $2 million potential collection recorded in the third quarter of 2012; partially offset by
- A $2 million increase related to a 1% increase in the volume of retail energy delivered primarily due to the effects of weather. Residential energy deliveries were up 2%, while commercial and industrial deliveries were comparable to the third quarter of 2012.

Total heating degree-days in the third quarter of 2013 were 55% higher than the third quarter of 2012 and 10% above average, and cooling degree-days were 16% higher than the third quarter of 2012 and 19% above average. The following table indicates the number of heating and cooling degree-days for the periods presented, along with 15-year averages provided by the National Weather Service, as measured at Portland International Airport:

	Heating Degree-days		Cooling Degree-days	
	2013	**2012**	**2013**	**2012**
July	2	14	168	115
August	3	3	203	201
September	85	41	86	79
Third quarter	90	58	457	395
15-year average for the year-to-date	82	81	385	387

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 availability, and customer demand. The $3 million, or 16%, increase in Wholesale revenues for the third quarter of 2013 compared to the third quarter of 2012, consisted of $8 million related to a 57% increase in average wholesale prices, driven by higher natural gas prices and less favorable hydro conditions, partially offset by $5 million related to a 25% decrease in wholesale sales volume.

Purchased power and fuel expense increased $8 million, or 4%, for the third quarter of 2013 compared to the third quarter of 2012. The increase consisted of $15 million related to a 9% increase in the average variable power cost, which is largely due to the unplanned plant outages, partially offset by $7 million related to a 4% decrease in total system load. During the third quarter of 2013, the Company incurred approximately $11 million of incremental replacement power costs related to the unplanned plant outages.

The average variable power cost increased to $36.79 per MWh in the third quarter of 2013 compared to $33.89 per MWh in the third quarter of 2012, driven by a 33% increase in the average price of purchased power combined with a decrease in energy received from hydro resources. Such increases were partially offset by a 30% decrease in the average cost of natural gas-fired generation and an increase in energy received from wind generating resources.

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

	Three Months Ended September 30,			
	2013		2012	
Sources of energy (MWh in thousands):				
Generation:				
Thermal:				
Coal	830	16%	995	18%
Natural gas	1,096	21	856	16
Total thermal	1,926	37	1,851	34
Hydro	314	6	331	6
Wind	372	7	341	7
Total generation	2,612	50	2,523	47
Purchased power:				
Term	940	18	1,895	35
Hydro	385	8	422	8
Wind	92	2	95	2
Spot	1,147	22	460	8
Total purchased power	2,564	50	2,872	53
Total system load	5,176	100%	5,395	100%
Less: wholesale sales	(581)		(771)	
Retail load requirement	4,595		4,624	

Energy from PGE-owned wind generating resources (Biglow Canyon) increased 9% in the third quarter of 2013 compared to the third quarter of 2012, and represented 8% and 7%, respectively, of the Company's retail load requirement. Energy received from Biglow Canyon fell short of that projected in PGE's AUT by 20% and 26% in the third quarters of 2013 and 2012, respectively.

Energy received from hydro resources during the third quarter of 2013, from both PGE-owned generating plants and purchased from mid-Columbia projects, decreased 7% compared with the third quarter of 2012 primarily due to less favorable hydro conditions in 2013. These resources provided approximately 15% of the Company's retail load requirement during the third quarter of 2013, compared with 16% during the third quarter of 2012. During the third quarter, total hydro generation exceeded projected levels included in the AUT for 2013 by 6%, compared with the third quarter of 2012 which exceeded such projected levels included in the AUT for 2012 by 14%.

The following table presents the actual April-to-September 2013 and 2012 runoff 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 1971 through 2000):

Location	Actual Runoff as a Percent of Normal *	
	2013	2012
Columbia River at The Dalles, Oregon	100%	126%
Mid-Columbia River at Grand Coulee, Washington	108	129
Clackamas River at Estacada, Oregon	102	133
Deschutes River at Moody, Oregon	98	118

* 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 increased approximately $4 million for the third quarter of 2013 compared with the third quarter of 2012, primarily due to a 9% increase in average variable power cost, which is largely due to incremental replacement power costs incurred during the third quarter of 2013 related to unplanned plant outages. For the third quarter of 2013, actual NVPC was $9 million above baseline NVPC, compared with $4 million below baseline NVPC for the third quarter of 2012.

Production and distribution expense increased $5 million, or 10%, in the third quarter of 2013 compared with the third quarter of 2012. The increase is primarily due to higher operating and maintenance costs related to the distribution system, including increased repair and restoration work.

Administrative and other expense in the third quarter of 2013 decreased $1 million, or 2%, compared to the third quarter of 2012, as the Company reduced its expense related to the reserve for uncollectible accounts by $1 million. A $2 million increase in employee pension expense resulting from a lower discount rate was largely offset by a decrease in employee incentive compensation expense.

Depreciation and amortization expense decreased $1 million, or 2%, in the third quarter of 2013 compared with the third quarter of 2012, largely due to an increase in costs deferred related to four capital projects as authorized in the Company's 2011 General Rate Case and a decrease in the asset retirement obligation resulting from the decommissioning of the Bull Run hydro facility. The decrease was partially offset by a $2 million increase resulting from capital additions.

Taxes other than income taxes expense increased $3 million, or 13%, primarily due to higher property taxes resulting from increased property values.

Interest expense decreased $2 million, or 7%, in the third quarter of 2013 compared to the third quarter of 2012, due to an increase in the allowance for borrowed funds used for construction driven by a higher average CWIP balance resulting from the commencement of the construction of Port Westward Unit 2, Carty Generating Station and Tucannon River Wind Farm in 2013, as well as a decrease in interest expense driven by the timing of the maturities and issuances of long-term debt.

Other income, net increased $6 million in the third quarter of 2013 compared with the third quarter of 2012, primarily due to higher earnings on the Non-qualified benefit plan trust assets, as well as an increase in the allowance for equity funds used for construction from the higher average CWIP balance.

Income tax expense was $4 million in the third quarter of 2013 compared with $19 million in the third quarter of 2012. The decrease is primarily due to the decrease in the annual estimated pre-tax income for 2013 compared to 2012, which was driven by the charge to expense related to Cascade Crossing, combined with other unfavorable impacts to 2013 pre-tax income.

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Nine Months Ended September 30, 2013 Compared with the Nine Months Ended September 30, 2012

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

	Nine Months Ended September 30,			
	2013		2012	
Revenues (1) (dollars in millions):				
Retail:				
Residential	$ 611	47 %	$ 630	47%
Commercial	461	35	476	36
Industrial	160	12	166	12
Subtotal	1,232	94	1,272	95
Other retail revenues, net	(6)	—	6	—
Total retail revenues	1,226	94	1,278	95
Wholesale revenues	59	4	38	3
Other operating revenues	26	2	26	2
Total revenues	$ 1,311	100 %	$ 1,342	100%
Energy deliveries (2) (MWh in thousands):				
Retail:				
Residential	5,469	34 %	5,506	34%
Commercial	5,540	34	5,566	34
Industrial	3,186	20	3,180	20
Total retail energy deliveries	14,195	88	14,252	88
Wholesale energy deliveries	1,892	12	1,861	12
Total energy deliveries	16,087	100 %	16,113	100%
Average number of retail customers:				
Residential	727,579	87 %	722,884	87%
Commercial	104,436	13	103,798	13
Industrial	264	—	261	—
Total	832,279	100 %	826,943	100%

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

Total revenues decreased $31 million, or 2%, for the nine months ended September 30, 2013 compared with the nine months ended September 30, 2012 as a result of the items described below.

Retail revenues decreased $52 million, or 4%, in the nine months ended September 30, 2013 compared with the nine months ended September 30, 2012, resulting primarily from the following items:

- A $33 million decrease resulting from lower average prices due primarily to the reduction in power costs as forecasted in the Company’s 2013 AUT and a slightly larger portion of energy deliveries going to customers who purchase their energy from ESSs;
- A $9 million decrease related to an industrial customer refund for cumulative over-billings that occurred over a period of several years as a result of a meter configuration error. Management believes the customer billing error is not material to any past reporting period. The Company corrected this matter in the second quarter of 2013 through an out of period adjustment as a reduction to Other retail revenues, net in the table above;

- A $5 million decrease related to lower volumes of energy delivered driven in part by warmer temperatures during the heating season in 2013 compared with the comparable period of 2012 and by the extra day in 2012 due to the leap year. Residential energy deliveries were down 1%, while commercial and industrial deliveries were comparable to the same period of 2012; and
- A $4 million decrease related to the Company's PCAM, as the potential refund to customers related to the 2011 PCAM was reduced in the nine months ended September 30, 2012, with no estimated refund to or collection from customers recorded in the nine months ended September 30, 2013.

Total heating degree-days for the nine months ended September 30, 2013 were 5% lower than the comparable period of 2012 and 3% below average, while cooling degree-days were 24% higher than the comparable period of 2012 and 19% above average. The following table indicates the number of heating and cooling degree-days for the periods presented, along with 15-year averages provided by the National Weather Service, as measured at Portland International Airport:

	Heating Degree-days		**Cooling Degree-days**	
	2013	**2012**	**2013**	**2012**
First quarter	1,902	1,967	—	—
Second quarter	593	709	82	40
Third quarter	90	58	457	395
Year-to-date	2,585	2,734	539	435
15-year average for the year-to-date	2,653	2,643	453	455

Wholesale revenues for the nine months ended September 30, 2013 increased $21 million, or 55%, from the nine months ended September 30, 2012, and consisted of $20 million related to a 51% increase in average wholesale price and $1 million related to a 2% increase in wholesale sales volume.

Purchased power and fuel expense increased $5 million, or 1%, for the nine months ended September 30, 2013 compared with the nine months ended September 30, 2012. The increase largely consisted of $12 million related to a 2% increase in the average variable power cost, which is largely due to the unplanned plant outages, partially offset by $9 million related to a 2% decrease in total system load. During the third quarter of 2013, the Company incurred approximately $11 million of incremental replacement power costs related to the unplanned plant outages.

The average variable power cost increased to $34.18 per MWh in the nine months ended September 30, 2013 compared with $33.41 per MWh in the nine months ended September 30, 2012, driven primarily by a 17% increase in the average price of purchased power combined with a decrease in energy received from hydro resources. The increase in average variable power cost was partially offset by a 22% decrease in the average cost of thermal generation, which resulted from a 24% decrease in the average cost of natural gas-fired generation and a 31% increase in the energy received from coal-fired generation.

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

	Nine Months Ended September 30,			
	2013		2012	
Sources of energy (MWh in thousands):				
Generation:				
Thermal:				
Coal	2,985	19%	2,280	14%
Natural gas	2,300	15	1,993	13
Total thermal	5,285	34	4,273	27
Hydro	1,231	8	1,461	9
Wind	1,001	6	964	6
Total generation	7,517	48	6,698	42
Purchased power:				
Term	4,821	30	6,042	38
Hydro	1,286	8	1,358	8
Wind	269	2	272	2
Spot	1,850	12	1,641	10
Total purchased power	8,226	52	9,313	58
Total system load	15,743	100%	16,011	100%
Less: wholesale sales	(1,892)		(1,861)	
Retail load requirement	13,851		14,150	

Energy from PGE-owned wind generating resources (Biglow Canyon) increased 4% in the nine months ended September 30, 2013 compared to the nine months ended September 30, 2012, and represented 7% of the Company's retail load requirement for both periods. Energy received from Biglow Canyon fell short of that projected in PGE's AUT by 14% and 17% in the nine months ended September 30, 2013 and 2012, respectively.

Energy received from hydro resources during the nine months ended September 30, 2013, from both PGE-owned generating plants and purchased from mid-Columbia projects, decreased 11% compared with the nine months ended September 30, 2012 primarily due to less favorable hydro conditions in 2013. These resources provided approximately 18% of the Company's retail load requirement during the nine months ended September 30, 2013, compared with 20% during the nine months ended September 30, 2012. Through September, total hydro generation exceeded projected levels included in the AUT for 2013 by 2%, compared with the same period of 2012, which exceeded such projected levels included in the AUT for 2012 by 12%.

Actual NVPC decreased approximately $17 million for the nine months ended September 30, 2013 compared with the nine months ended September 30, 2012, due to a 51% increase in average wholesale sales price and a 2% decrease in total system load, partially offset by a 2% increase in the average variable power cost. For the nine months ended September 30, 2013, actual NVPC was $5 million below baseline NVPC, compared with $14 million below baseline NVPC for the nine months ended September 30, 2012.

Production and distribution expense increased $16 million, or 10%, in the nine months ended September 30, 2013 compared with the nine months ended September 30, 2012. The increase is primarily due to $6 million related to planned overhaul and repair costs at Colstrip and Coyote Springs, $4 million of expense associated with the Company's benchmark proposals that were not selected in the RFP process for new generation, $3 million related to increased delivery system repair and restoration work, and $2 million for the warranty extension for Biglow Canyon Phase III.

Cascade Crossing transmission project reflects $52 million of costs expensed in the second quarter of 2013, which were previously recorded as CWIP.

Administrative and other expense decreased $2 million, or 1%, in the nine months ended September 30, 2013 compared to the nine months ended September 30, 2012, as a result of lower labor costs and a decrease in expense related to the reserve for uncollectible accounts. A $5 million increase in employee pension expense resulting from a lower discount rate was largely offset by decreases in employee incentive compensation and legal and consulting expenses.

Depreciation and amortization expense decreased $2 million, or 1%, in the nine months ended September 30, 2013 compared with the nine months ended September 30, 2012, largely due to the deferral of costs related to four capital projects as authorized in the Company's 2011 General Rate Case, the decrease in the asset retirement obligation resulting from the decommissioning of the Bull Run hydro facility, as well as the deferral in 2012 of tax credits related to the Independent Spent Fuel Storage Installation located at the former Trojan nuclear power plant. The decrease was partially offset by a $3 million increase resulting from capital additions.

Taxes other than income taxes expense increased $2 million, or 3%, primarily due to higher property taxes resulting from increased property values.

Interest expense decreased $7 million, or 9%, in the nine months ended September 30, 2013 compared to the nine months ended September 30, 2012, primarily due to a decrease in the average balance of debt outstanding for 2013, as well as an increase in the allowance for borrowed funds used for construction driven by a higher average CWIP balance resulting from the commencement of the construction of Port Westward Unit 2, Carty Generating Station and Tucannon River wind farm in 2013.

Other income, net increased $7 million, or 117%, in the nine months ended September 30, 2013 compared with the nine months ended September 30, 2012, primarily due to an increase in the allowance for equity funds used for construction from the higher average CWIP balance, as well as an increase in earnings from the Non-qualified benefit plan trust assets.

Income tax expense decreased $33 million in the nine months ended September 30, 2013 compared with the nine months ended September 30, 2012, with effective tax rates of 14.9% and 27.7%, respectively. The decrease in the effective tax rate is primarily due to a decrease in the estimated annual pre-tax income for 2013 compared to 2012, which was driven by the charge to expense related to Cascade Crossing, combined with other unfavorable impacts to 2013 pre-tax income.

Liquidity and Capital Resources

Capital Requirements

The following table presents PGE's estimated cash requirements for the years indicated (in millions, excluding AFDC):

	2013	2014	2015	2016	2017
Ongoing capital expenditures [1]	$ 310	$ 325	$ 280	$ 265	$ 240
Port Westward Unit 2	165	125	10	—	—
Carty Generating Station	125	170	110	45	—
Tucannon River Wind Farm	110	375	15	—	—
Hydro licensing and construction [2]	10	40	35	5	5
Total capital expenditures	$ 720 [3]	$ 1,035	$ 450	$ 315	$ 245
Long-term debt maturities	$ 100	$ —	$ 70	$ 67	$ 58

(1) Consists primarily of upgrades to, and replacement of, transmission, distribution, and generation infrastructure, as well as new customer connections.
(2) Relate primarily to modifications to the Company's hydro facilities to enhance fish passage and survival, as required by conditions contained in the operating licenses.
(3) Includes preliminary engineering and removal costs, which are included in other net operating activities in the condensed consolidated statements of cash flows.

Liquidity

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

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

	Nine Months Ended September 30,	
	2013	2012
Cash and cash equivalents, beginning of period	$ 12	$ 6
Net cash provided by (used in):		
Operating activities	459	450
Investing activities	(491)	(209)
Financing activities	111	(91)
Increase in cash and cash equivalents	79	150
Cash and cash equivalents, end of period	$ 91	$ 156

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 and deferred income taxes, included in net income during a given period, and increased $9 million for the nine months ended September 30, 2013 compared with the nine months ended September 30, 2012. Such increase was largely due to the receipt of $44 million in the third quarter of 2013 related to the settlement of a legal matter, offset by a 49% decrease in net income.

Cash provided by operations includes the recovery in customer prices of non-cash charges for depreciation and amortization. PGE estimates that such charges will range from $240 million to $250 million in 2013, with total cash provided by operations anticipated to range from $490 million to $500 million. The remaining estimated cash flows from operations in 2013 is expected from normal operating activities.

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 distribution, transmission, and generation facilities. The $282 million increase in net cash used in investing activities in the nine months ended September 30, 2013 compared with the nine months ended September 30, 2012 was due primarily to a $235 million increase in capital expenditures, largely due to the construction of three new generation projects (PW2, Carty and Tucannon River), and a $44 million contribution to the Nuclear decommissioning trust in the third quarter of 2013.

The Company plans a total of approximately $720 million in capital expenditures for 2013 related to the construction of new generating facilities and upgrades and replacement of transmission, distribution, and generation infrastructure. See the Capital Requirements section above for additional information.

Cash Flows from Financing Activities—Financing activities provide supplemental cash for both day-to-day operations and capital requirements as needed. During the nine months ended September 30, 2013, cash provided by such activities consisted of net proceeds received from the issuance of common stock in the amount of $67 million and FMBs in the amount of $223 million, partially offset by the repayment of FMBs of $100 million and commercial paper of $17 million, and the payment of dividends of $62 million. During the nine months ended September 30, 2012, cash used in financing activities consisted of the repayment of commercial paper in the amount of $30 million and the payment of dividends of $61 million.

Dividends on Common Stock

While the Company 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 2013 consist of the following:

Declaration Date	Record Date	Payment Date	Dividends Declared Per Common Share
February 20, 2013	March 25, 2013	April 15, 2013	$ 0.270
May 22, 2013	June 25, 2013	July 15, 2013	0.275
July 31, 2013	September 25, 2013	October 15, 2013	0.275
October 30, 2013	December 26, 2013	January 15, 2014	0.275

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, capital expenditure requirements, alternatives available to investors, and other factors. The Company's ability to obtain and renew such financing depends on its credit ratings, as well as on credit markets, both generally and for electric utilities in particular. Management believes that the availability of credit facilities, the expected ability to issue long-term debt and equity securities, and cash expected to be generated from operations provide sufficient liquidity to meet the Company's anticipated capital and operating requirements. However, the Company's ability to issue long-term debt and equity could be adversely affected by changes in capital market conditions.

To help meet anticipated capital expenditure requirements and contractual maturities of long-term debt over the next two years, PGE completed a public offering of its common stock and entered into a bond purchase agreements for FMBs in June and October 2013. These transactions were structured to allow for funds generally to be provided to the Company in increments that align with the timing and amount of capital expenditures and the contractual maturities of long-term debt.

Short-term Debt. PGE has approval from the FERC to issue short-term debt up to a total of $700 million through February 6, 2014 and currently has the following unsecured revolving credit facilities:

- A $400 million syndicated credit facility scheduled to terminate November 2017; and
- A $300 million syndicated credit facility scheduled to terminate December 2016.

These revolving credit facilities supplement operating cash flow and provide a primary source of liquidity. Pursuant to the terms of the agreements, the revolving credit facilities may be used for general corporate purposes, backup for commercial paper borrowings, and the issuance of standby letters of credit. The Company also has two letter of credit facilities under which it may obtain letters of credit in an aggregate amount not to exceed $60 million.

As of September 30, 2013, PGE had no borrowings outstanding under the revolving credit facilities, no commercial paper outstanding, and $56 million of letters of credit issued. As of September 30, 2013, the aggregate available capacity under the credit facilities was $696 million.

Long-term Debt. During the nine months ended September 30, 2013, PGE had the following long-term debt transactions:

- In August, PGE repaid $50 million of 5.625% Series FMBs in accordance with the scheduled maturity and issued $75 million of 4.47% Series FMBs due 2043;
- In June, the Company issued $150 million of 4.47% Series FMBs due 2044; and
- In April, PGE repaid $50 million of 4.45% Series FMBs in accordance with the scheduled maturity.

As of September 30, 2013, total long-term debt outstanding was $1,761 million. In addition, PGE owns $27 million of its Pollution Control Revenue Bonds, which may be remarketed at a later date, at the Company's option.

In October 2013, PGE entered into a bond purchase agreement under which the Company agreed to sell to certain institutional buyers an aggregate principal amount of $155 million of FMBs in two tranches. PGE expects to issue $105 million of 4.74% Series FMBs due 2042 and $50 million of 4.84% Series FMBs due 2048 in November and December 2013, respectively. PGE does not expect to issue any additional long-term debt in 2013.

Equity. On June 11, 2013, PGE entered into an EFSA in connection with the public offering of 11,100,000 shares of its common stock, with an initial value of $317 million. Pursuant to the EFSA, a forward counterparty borrowed 11,100,000 shares of PGE's common stock from third parties and such borrowed shares were sold in a registered public offering. PGE receives proceeds from the sale of the common stock when the EFSA is physically settled. Through September 30, 2013, the Company had the following equity transactions in connection with the offering:

- On June 17, 2013, the underwriters exercised their over-allotment option in full and PGE issued 1,665,000 shares of common stock for proceeds of $47 million, net of an underwriters' discount of $2 million; and

- On August 21, 2013, the Company issued 700,000 shares of common stock for proceeds of $20 million, net of an underwriters' discount of $1 million.

As of September 30, 2013, the Company could have physically settled the EFSA by delivering 10,400,000 shares of PGE common stock to the forward counterparty in exchange for cash of $291 million. The Company anticipates physical settlement of the EFSA by delivery of newly issued shares on or before June 11, 2015. For additional information on the EFSA, see Note 6, Equity, in the Notes to the Condensed Consolidated Financial Statements. PGE does not anticipate any additional issuances of equity through the remainder of 2013.

Capital Structure. PGE's financial objectives include the balancing of debt and equity to maintain a low weighted average cost of capital while retaining sufficient flexibility to meet the Company's financial obligations. The Company attempts to maintain a common equity ratio (common equity to total consolidated capitalization, including current debt maturities) of approximately 50%. Achievement of this objective, while sustaining sufficient cash flow, is necessary to maintain investment grade credit ratings and allow access to long-term capital at attractive interest rates. PGE's common equity ratios were 50.5% and 51.1% as of September 30, 2013 and December 31, 2012, respectively.

Credit Ratings and Debt Covenants

PGE's secured and unsecured debt is rated investment grade by Moody's Investors Service (Moody's) and Standard and Poor's Ratings Services (S&P). PGE's current credit ratings and outlook are as follows:

	Moody's	**S&P**
First Mortgage Bonds	A2	A-
Senior unsecured debt	Baa1	BBB
Commercial paper	Prime-2	A-2
Outlook	Stable	Stable

In June 2013, Moody's upgraded their credit ratings on the Company's First Mortgage Bonds to 'A2' from 'A3' and senior unsecured debt to 'Baa1' from 'Baa2,' with no changes to their rating on PGE's commercial paper, and revised their outlook on PGE to 'Stable' from 'Positive.' The credit rating upgrades reflect a constructive regulatory environment with the timely recovery of prudently incurred costs, and a strong and stable financial profile with adequate liquidity to support a significant construction cycle. PGE is embarking on a significant capital plan for the construction of new natural gas-fired plants and a new wind farm, all of which are expected to be prudently financed and to provide rate base growth and enhanced cash flow over the near-term.

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 on PGE's condensed consolidated balance sheets, while any letters of credit issued are not reflected on the Company's condensed consolidated balance sheets.

As of September 30, 2013, PGE had posted approximately $62 million of collateral with these counterparties, consisting of $36 million in cash and $26 million in letters of credit, $6 million of which is affiliated with master netting agreements. Based on the Company's energy portfolio, estimates of energy market prices, and the level of collateral outstanding as of September 30, 2013, the approximate amount of additional collateral that could be requested upon a single agency downgrade to below investment grade is approximately $84 million and decreases to approximately $43 million by December 31, 2013, and $25 million by December 31, 2014. The amount of additional collateral that could be requested upon a dual agency downgrade to below investment grade is approximately $225 million at September 30, 2013 and decreases to approximately $156 million by December 31, 2013, and $94 million by December 31, 2014.

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 under the credit facilities 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 September 30, 2013, under the most restrictive issuance test in the Indenture of Mortgage and Deed of Trust, the Company could have issued up to approximately $189 million of additional FMBs. PGE entered into a bond purchase agreement in October 2013 for the issuance of $155 million in two tranches that are expected to be funded in November and December 2013. PGE does not expect to issue any additional long-term debt in 2013. Any issuance 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 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 facilities contain 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 ratio). As of September 30, 2013, the Company's debt ratio, as calculated under the credit agreements, was 49.6%.

Off-Balance Sheet Arrangements

In June 2013, PGE entered into an EFSA in connection with a registered public offering of its common stock and a bond purchase agreement. The Company may settle the EFSA with issuance of PGE common stock, for cash or net share settlement from time-to-time, in whole or part, through June 11, 2015. For additional information on the EFSA, see Note 6, Equity, in the Notes to the Condensed Consolidated Financial Statements. In October 2013, the Company entered into a bond purchase agreement and agreed to sell, in two tranches, an aggregate principal amount of $155 million of FMBs to certain institutional buyers. The two tranches of $105 million and $50 million are expected to be issued in the fourth quarter of 2013.

PGE has no other 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 2013 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, 2012, filed with the SEC on February 22, 2013. Such obligations have not changed materially as of September 30, 2013, with the following exceptions:

- PGE entered into agreements for the construction of PW2, Carty and Tucannon River. As a result, capital and other purchase commitments increased by the following amounts: $148 million in 2013; $607 million in 2014; $88 million in 2015; and $29 million in 2016.
- PGE issued $225 million of 4.47% Series FMBs, consisting of $150 million due 2044 and $75 million due 2043. As a result, future interest on long-term debt increased by the following amounts: $4 million for 2013; $10 million each year for 2014 through 2017; and $264 million thereafter through the 2044 maturity date referenced in the preceding sentence.

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, 2012, filed with the SEC on February 22, 2013.

Item 4. Controls and Procedures.

Disclosure Controls and Procedures

PGE's management, under the supervision and with the participation of its Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the Company's disclosure controls and procedures as required by Exchange Act Rule 13a-15(b) as of the end of the period covered by this report. Based on that evaluation, PGE's Chief Executive Officer and Chief Financial Officer have concluded that, as of September 30, 2013, 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, 2012, filed with the SEC on February 22, 2013 and Part II, Item 1 of the Company's Quarterly Report on Form 10-Q for the quarterly periods ended March 31, 2013 and June 30, 2013, filed with the SEC on May 1, 2013 and August 2, 2013, respectively.

<u>Citizens' Utility Board of Oregon v. Public Utility Commission of Oregon and Utility Reform Project and Colleen O'Neill v. Public Utility Commission of Oregon</u>, Public Utility Commission of Oregon, Marion County Oregon Circuit Court, the Court of Appeals of the State of Oregon, and the Oregon Supreme Court.

On October 18, 2013, the Oregon Supreme Court accepted plaintiffs' petition seeking review of the February 6, 2013 Oregon Court of Appeals decision. Oral argument is scheduled for March 4, 2014.

<u>Sierra Club and Montana Environmental Information Center v. PPL Montana LLC, Avista Corporation, Puget Sound Energy, Portland General Electric Company, Northwestern Corporation, and PacifiCorp</u>, U.S. District Court for the District of Montana.

On July 30, 2012, PGE received a Notice of Intent to Sue (Notice) for violations of the Clean Air Act (CAA) at Colstrip Steam Electric Station (Colstrip) from counsel on behalf of the Sierra Club and the Montana Environmental Information Center (MEIC). The Notice was also addressed to the other Colstrip co-owners, including PPL Montana, LLC - the operator of Colstrip. PGE has a 20% ownership interest in Units 3 and 4 of Colstrip. The Notice alleges certain violations of the CAA, 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 Colstrip 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. 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 Colstrip co-owners, including PGE, for these and additional alleged violations of various environmental related regulations. The plaintiffs are seeking relief that includes civil penalties and an injunction preventing the co-owners from operating Colstrip 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. On May 3, 2013, the defendants filed a motion to dismiss 36 of the 39 claims in the suit. On September 27, 2013, the plaintiffs filed an amended complaint that deleted the 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. This matter is scheduled for trial in October 2014.

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, 2012, filed with the SEC on February 22, 2013.

Item 6. Exhibits.

Exhibit Number	Description
3.1	Second Amended and Restated Articles of Incorporation of Portland General Electric Company (incorporated by reference to Exhibit 3.1 to the Company's Quarterly Report on Form 10-Q filed August 3, 2009).
3.2	Ninth Amended and Restated Bylaws of Portland General Electric Company (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed October 27, 2011).
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:	October 31, 2013	By:	/s/ James F. Lobdell
			James F. Lobdell
			Senior Vice President of Finance, *Chief Financial Officer and Treasurer*
			(duly authorized officer and principal financial officer)

Exhibit 31.1

CERTIFICATION

I, James J. Piro, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: October 31, 2013

By: /s/ James J. Piro

James J. Piro

President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, James F. Lobdell, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: October 31, 2013

By: /s/ James F. Lobdell

James F. Lobdell

Senior Vice President of Finance,
Chief Financial Officer and Treasurer

Exhibit 32

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

We, James J. Piro, President and Chief Executive Officer, and James F. Lobdell, Senior Vice President of Finance, Chief Financial Officer and Treasurer, of Portland General Electric Company (the "Company"), hereby certify that the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2013, as filed with the Securities and Exchange Commission on November 1, 2013 pursuant to Section 13(a) of the Securities Exchange Act of 1934 (the "Report"), fully complies with the requirements of that section.

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

/s/ James J. Piro	/s/ James F. Lobdell
James J. Piro	James F. Lobdell
President and Chief Executive Officer	*Senior Vice President of Finance, Chief Financial Officer and Treasurer*
Date: October 31, 2013	Date: October 31, 2013