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, 2011**

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: **1-5532-99**

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 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 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, 2011 is 75,345,583 shares.

PORTLAND GENERAL ELECTRIC COMPANY
FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2011

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DEFINITIONS

The following abbreviations and acronyms are used throughout this document:

Abbreviation or Acronym	Definition
AFDC	Allowance for funds used during construction
AUT	Annual Power Cost Update Tariff
Biglow Canyon	Biglow Canyon Wind Farm
Boardman	Boardman coal-fired generating plant
Cascade Crossing	Cascade Crossing Transmission Project
CERS	California Energy Resources Scheduling
Colstrip	Colstrip Units 3 and 4 coal-fired generating plant
Coyote Springs	Coyote Springs Unit 1 natural gas-fired generating plant
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IRP	Integrated Resource Plan
ISFSI	Independent Spent Fuel Storage Installation
kV	Kilovolt = one thousand volts of electricity
LLC	Limited Liability Company
Moody's	Moody's Investors Service
MW	Megawatts
MWa	Average megawatts
MWh	Megawatt hours
NVPC	Net Variable Power Costs
OPUC	Public Utility Commission of Oregon
PCAM	Power Cost Adjustment Mechanism
S&P	Standard & Poor's Ratings Services
SB 408	Oregon Senate Bill 408 (Oregon Revised Statutes 757.268)
SB 967	Oregon Senate Bill 967
SEC	Securities and Exchange Commission
Trojan	Trojan Nuclear Plant
URP	Utility Reform Project
VIE	Variable Interest Entity

PART I — FINANCIAL INFORMATION

Item 1. Financial Statements.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Revenues, net	$ 439	$ 464	$ 1,334	$ 1,328
Operating expenses:				
Purchased power and fuel	182	203	545	613
Production and distribution	50	42	147	127
Administrative and other	55	47	158	140
Depreciation and amortization	59	59	170	173
Taxes other than income taxes	25	23	74	67
Total operating expenses	371	374	1,094	1,120
Income from operations	68	90	240	208
Other income (expense):				
Allowance for equity funds used during construction	1	4	3	12
Miscellaneous income (expense), net	(4)	3	(1)	1
Other income (expense), net	(3)	7	2	13
Interest expense	27	27	82	82
Income before income taxes	38	70	160	139
Income taxes	11	22	42	40
Net income	27	48	118	99
Less: net loss attributable to noncontrolling interests	—	(1)	—	(1)
Net income attributable to Portland General Electric Company	$ 27	$ 49	$ 118	$ 100
Weighted-average shares outstanding (in thousands):				
Basic	75,342	75,295	75,329	75,267
Diluted	75,358	75,311	75,345	75,282
Earnings per share:				
Basic	$ 0.36	$ 0.65	$ 1.57	$ 1.32
Diluted	$ 0.36	$ 0.65	$ 1.57	$ 1.32
Dividends declared per common share	$ 0.265	$ 0.260	$ 0.790	$ 0.775

See accompanying notes to condensed consolidated financial statements.

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

	September 30, 2011	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 97	$ 4
Accounts receivable, net	136	137
Unbilled revenues	72	93
Inventories	69	56
Margin deposits	83	83
Regulatory assets - current	208	221
Other current assets	75	67
Total current assets	**740**	**661**
Electric utility plant, net	4,255	4,133
Regulatory assets - noncurrent	481	544
Non-qualified benefit plan trust	36	44
Nuclear decommissioning trust	37	34
Other noncurrent assets	62	75
Total assets	**$ 5,611**	**$ 5,491**

See accompanying notes to condensed consolidated financial statements.

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

	September 30, 2011	December 31, 2010
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 172	$ 169
Liabilities from price risk management activities - current	196	188
Short-term debt	—	19
Current portion of long-term debt	—	10
Regulatory liabilities - current	12	25
Other current liabilities	131	78
Total current liabilities	**511**	**489**
Long-term debt, net of current portion	1,798	1,798
Regulatory liabilities - noncurrent	712	657
Deferred income taxes	480	445
Liabilities from price risk management activities - noncurrent	147	188
Unfunded status of pension and postretirement plans	102	140
Non-qualified benefit plan liabilities	99	97
Other noncurrent liabilities	106	78
Total liabilities	**3,955**	**3,892**
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, 2011 and December 31, 2010	—	—
Common stock, no par value, 160,000,000 shares authorized; 75,345,351 and 75,316,419 shares issued and outstanding as of September 30, 2011 and December 31, 2010, respectively	833	831
Accumulated other comprehensive loss	(5)	(5)
Retained earnings	825	766
Total Portland General Electric Company shareholders' equity	1,653	1,592
Noncontrolling interests' equity	3	7
Total equity	**1,656**	**1,599**
Total liabilities and equity	**$ 5,611**	**$ 5,491**

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,	
	2011	**2010**
Cash flows from operating activities:		
Net income	$ 118	$ 99
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	170	173
(Decrease) increase in net liabilities from price risk management activities	(26)	202
Regulatory deferral - price risk management activities	26	(202)
Deferred income taxes	40	48
Power cost deferrals, net	17	(1)
Renewable adjustment clause deferrals	16	1
Regulatory deferral of settled derivative instruments	15	37
Senate Bill 408 deferrals, net	(5)	(30)
Allowance for equity funds used during construction	(3)	(12)
Decoupling mechanism deferrals, net	—	(9)
Other non-cash income and expenses, net	29	21
Changes in working capital:		
Decrease in receivables	22	54
Increase in margin deposits, net	—	(61)
Income tax refund received	8	53
Increase (decrease) in payables and accrued liabilities	3	(16)
Other working capital items, net	13	5
Contribution to pension plan	(26)	(30)
Contribution to the voluntary employees' beneficiary association trust	(14)	—
Other, net	(4)	(15)
Net cash provided by operating activities	**399**	**317**
Cash flows from investing activities:		
Capital expenditures	(215)	(384)
Sales of Nuclear decommissioning trust securities	39	27
Purchases of Nuclear decommissioning trust securities	(41)	(25)
Distribution from Nuclear decommissioning trust	—	19
Other, net	3	(1)
Net cash used in investing activities	**(214)**	**(364)**

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,	
	2011	**2010**
Cash flows from financing activities:		
Proceeds from issuance of long-term debt	$ —	$ 249
Payments on long-term debt	(10)	(186)
Borrowings on short-term debt	—	11
(Payments) borrowings on commercial paper, net	(19)	9
Dividends paid	(59)	(58)
Debt issuance costs	—	(2)
Noncontrolling interests' capital distributions	(4)	—
Net cash (used in) provided by financing activities	**(92)**	**23**
Change in cash and cash equivalents	93	(24)
Cash and cash equivalents, beginning of period	4	31
Cash and cash equivalents, end of period	**$ 97**	**$ 7**
Supplemental cash flow information is as follows:		
Cash paid for interest, net of amounts capitalized	$ 66	$ 62
Cash paid for income taxes	3	—
Non-cash investing and financing activities:		
Accrued capital additions	22	8
Accrued dividends payable	21	20
Preliminary engineering transferred to Construction work in progress from Other noncurrent assets	7	—

See accompanying notes to condensed consolidated financial statements.

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

NOTE 1: BASIS OF PRESENTATION

Nature of Business

Portland General Electric Company (PGE or the Company) is a single, vertically integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the state of Oregon. The Company also sells electricity and natural gas in the wholesale market to utilities, brokers, and power and fuel marketers located in the United States and Canada. 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 within the state of Oregon. The Company served 824,817 retail customers as of September 30, 2011.

Condensed Consolidated Financial Statements

These condensed consolidated financial statements have been prepared pursuant to the rules and regulations of the 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.

The financial information included herein for the three and nine month periods ended September 30, 2011 and 2010 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 operations 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, 2010 is derived from the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2010, included in Item 8 of PGE's Annual Report on Form 10-K, filed with the SEC on February 25, 2011, and should be read in conjunction with such consolidated financial statements.

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.

Reclassifications

PGE has separately presented regulatory deferrals related to the renewable adjustment clause from Other non-cash income and expenses, net in the Cash flows from operating activities section of the consolidated statement of cash flows for the nine months ended September 30, 2010 to conform with the 2011 presentation.

Recent Accounting Pronouncements

Accounting Standards Update (ASU) 2010-06, *Fair Value Measurements and Disclosures (Topic 820) - Improving Disclosures about Fair Value Measurements* (ASU 2010-06) requires, among other matters, separate reporting about purchases, sales, issuances, and settlements for Level 3 fair value measurements. For additional information on Level 3, see Note 3, Fair Value of Financial Instruments. In accordance with the provisions of ASU 2010-06, PGE adopted this requirement of ASU 2010-06 on January 1, 2011, which did not have a material impact on the Company's consolidated financial position, consolidated results of operations, or consolidated cash flows. All other requirements of ASU 2010-06 were adopted on January 1, 2010 in accordance with ASU 2010-06.

In May 2011, ASU 2011-04, *Fair Value Measurements and Disclosures (Topic 820) - Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs* (ASU 2011-04) was issued. Many of the amendments in ASU 2011-04 change the wording used to describe principles and requirements to align with International Financial Reporting Standards as issued by the International Accounting Standards Board, and are not intended to change the application of Topic 820. Some of the amendments clarify the Financial Accounting Standards Board's intent on the application of existing fair value guidance or change a particular principle or requirement for measuring fair value or fair value disclosures. The amendments in ASU 2011-04 are to be applied prospectively and are effective for interim and annual periods beginning after December 15, 2011 for public entities, with early application not permitted. PGE will adopt the amendments contained in ASU 2011-04 on January 1, 2012, which are not expected to have a material impact on the Company's consolidated financial position, consolidated results of operations, or consolidated cash flows.

In June 2011, ASU 2011-05, *Comprehensive Income (Topic 220) - Presentation of Comprehensive Income* (ASU 2011-05) was issued. The amendments of ASU 2011-05 require that an entity report items of other comprehensive income in one of two ways: (i) a single statement with components of net income and total net income, the components of other comprehensive income and total other comprehensive income, and a total for comprehensive income; or (ii) two statements with components of net income and total net income in the first statement, immediately followed by a statement that presents the components of other comprehensive income, a total for other comprehensive income, and a total for comprehensive income. The amendments in ASU 2011-05 are to be applied retrospectively and are effective for interim and annual periods beginning after December 15, 2011, with early application permitted. PGE will adopt the amendments contained in ASU 2011-05 on January 1, 2012, which will not have a material impact on the Company's consolidated financial position, consolidated results of operations, or consolidated cash flows.

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, 2011 and December 31, 2010.

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

	Nine Months Ended September 30,	
	2011	2010
Balance as of beginning of period	$ 5	$ 5
Provision, net	6	5
Amounts written off, less recoveries	(6)	(5)
Balance as of end of period	$ 5	$ 5

Inventories

Inventories consist primarily of materials, supplies, and fuel. Materials and supplies inventories are used in operations and maintenance and capital activities, and are recorded at average cost. Fuel inventories include natural gas, coal, and oil, which are used in PGE's generating plants, and are recorded at average cost. PGE periodically assesses the realizability of inventory for purposes of determining that inventory is recorded at the lower of average cost or market.

Electric Utility Plant, Net

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

	September 30, 2011	December 31, 2010
Electric utility plant	$ 6,509	$ 6,279
Construction work in progress	134	125
Total cost	6,643	6,404
Less: accumulated depreciation and amortization	(2,388)	(2,271)
Electric utility plant, net	$ 4,255	$ 4,133

In 2011, $7 million of costs related to the Cascade Crossing Transmission Project were transferred to Construction work in progress. Such costs were previously included within preliminary engineering, which is included in Other noncurrent assets in the condensed consolidated balance sheets.

Accumulated depreciation and amortization in the table above includes accumulated amortization related to intangible assets of $147 million and $133 million as of September 30, 2011 and December 31, 2010, respectively. Amortization expense related to intangible assets was $5 million and $4 million for the three months ended September 30, 2011 and 2010, respectively, and $14 million and $13 million for the nine months ended September 30, 2011 and 2010, respectively.

Regulatory Assets and Liabilities

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

	September 30, 2011		December 31, 2010	
	Current	Noncurrent	Current	Noncurrent
Regulatory assets:				
Price risk management	$ 187	$ 147	$ 175	$ 185
Pension and other postretirement plans	—	205	—	213
Deferred income taxes	—	89	—	95
Deferred broker settlements	8	—	24	—
Renewable energy deferral	6	—	22	—
Debt reacquisition costs	—	21	—	23
Other	7	19	—	28
Total regulatory assets	$ 208	$ 481	$ 221	$ 544
Regulatory liabilities:				
Asset retirement removal costs	$ —	$ 626	$ —	$ 588
Asset retirement obligations	—	35	—	33
Power cost adjustment mechanism	—	17	—	—
Regulatory treatment of income taxes (SB 408)	6	1	5	9
Trojan ISFSI pollution control tax credits	5	6	18	4
Other	1	27	2	23
Total regulatory liabilities	$ 12	$ 712	$ 25	$ 657

Other Current Liabilities

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

	September 30, 2011	December 31, 2010
Accrued taxes payable	$ 66	$ 22
Accrued interest payable	36	26
Accrued dividends payable	21	20
Other	8	10
Total other current liabilities	$ 131	$ 78

Other Noncurrent Liabilities

During 2011, an updated decommissioning study for the Company's Boardman coal-fired plant was completed, which assumed that Boardman's coal-fired operations cease in 2020 rather than 2040. As a result of the study, PGE increased its asset retirement obligation related to Boardman by approximately $23 million, with a corresponding increase in the cost basis of the plant, included in Electric utility plant, net on the condensed consolidated balance sheets. Such transaction is non-cash and is excluded from investing activities in the statement of cash flows for the nine months ended September 30, 2011.

Credit Facilities

PGE has the following unsecured revolving credit facilities:

- A $370 million syndicated credit facility, with $10 million and $360 million scheduled to terminate in July 2012 and July 2013, respectively;
- A $200 million syndicated credit facility, which is scheduled to terminate in December 2012; and
- A $30 million credit facility, which is scheduled to terminate in June 2013.

Pursuant to the individual terms of the agreements, all credit facilities may be used for general corporate purposes and as backup for commercial paper borrowings. The $370 million and $30 million credit facilities also permit the issuance of standby letters of credit. All credit facilities 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, 2011, PGE was in compliance with this covenant with a 52.1% debt to total capital ratio.

The Company has a commercial paper program under which it may issue commercial paper for terms of up to 270 days, limited to the unused amount of credit under the 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 $750 million through February 6, 2012. The authorization contains a standard provision which provides that if utility assets financed by unsecured debt are divested, then a proportionate share of the unsecured debt must also be divested.

As of September 30, 2011, PGE had $89 million of letters of credit outstanding under the credit facilities and no commercial paper or borrowings outstanding. As of September 30, 2011, the aggregate unused credit available under the credit facilities was $511 million.

Pension and Other Postretirement Benefits

Components of net periodic benefit cost are as follows for the three months ended September 30 (in millions):

	Defined Benefit Pension Plan		Other Postretirement Benefit Plans		Non-Qualified Benefit Plans	
	2011	2010	2011	2010	2011	2010
Service cost	$ 3	$ 3	$ 1	$ —	$ —	$ —
Interest cost	7	7	1	1	1	—
Expected return on plan assets	(10)	(10)	—	(1)	—	—
Amortization of prior service cost	—	1	—	1	—	—
Amortization of net actuarial loss	2	—	—	—	—	1
Net periodic benefit cost	$ 2	$ 1	$ 2	$ 1	$ 1	$ 1

Components of net periodic benefit cost are as follows for the nine months ended September 30 (in millions):

	Defined Benefit Pension Plan		Other Postretirement Benefit Plans		Non-Qualified Benefit Plans	
	2011	2010	2011	2010	2011	2010
Service cost	$ 9	$ 9	$ 2	$ 1	$ —	$ —
Interest cost	21	21	3	3	2	1
Expected return on plan assets	(30)	(30)	—	(1)	—	—
Amortization of prior service cost	—	1	—	1	—	—
Amortization of net actuarial loss	6	2	—	1	—	1
Net periodic benefit cost	$ 6	$ 3	$ 5	$ 5	$ 2	$ 2

NOTE 3: FAIR VALUE OF FINANCIAL INSTRUMENTS

The Company determines the fair value of financial instruments, both assets and liabilities recognized and not recognized in PGE's condensed consolidated balance sheets, for which it is practicable to estimate fair value based on the following inputs as of September 30, 2011 and December 31, 2010:

- Derivative instruments are recorded at fair value and are based on published market indices, which may be adjusted for market variables such as location pricing differences and/or the effects of liquidity at different locations. The Company also values certain derivative instruments using either standardized or internally developed models;

- Certain trust assets, consisting of money market funds and fixed income securities included in the Nuclear decommissioning trust and marketable securities included in the Non-qualified benefit plan trust, are recorded at fair value and are based on quoted market prices; and

- The fair value of long-term debt is estimated based on the quoted market prices for the same or similar issues or on the current rates offered to PGE for debt of similar remaining maturities. As of September 30, 2011, the estimated aggregate fair value of PGE's long-term debt was $2,028 million, compared to its $1,798 million carrying amount. As of December 31, 2010, the estimated aggregate fair value of PGE's long-term debt was $1,968 million, compared to its $1,808 million carrying amount.

A fair value hierarchy is used to prioritize the inputs to the valuation techniques used to measure fair value. The three broad 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. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as listed debt and equity securities and U.S. government treasury securities, as well as exchange-traded derivatives from time to time.

Level 2 — Pricing inputs are other than quoted market prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date, and include quoted market prices for similar, but not identical, assets or liabilities. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. 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 non-exchange-traded derivatives, such as over-the-counter forwards and swaps, and debt securities other than U.S. government treasury securities.

Level 3 — Pricing inputs include significant inputs that are generally less observable than objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Level 3 instruments include those that may be more structured or otherwise tailored to meet the Company's retail energy requirements. At each balance sheet date, the Company performs an analysis of all instruments subject to fair value measurement and includes in Level 3 all of those instruments whose fair value is based on significant unobservable inputs.

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

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

	September 30, 2011			
	Level 1	Level 2	Level 3	Total
Assets:				
Nuclear decommissioning trust [1]:				
Money market funds	$ —	$ 15	$ —	$ 15
Debt securities:				
U.S. treasury securities	6	—	—	6
Corporate debt securities	—	6	—	6
Mortgage-backed securities	—	5	—	5
Municipal securities	—	3	—	3
Asset-backed securities	—	2	—	2
Non-qualified benefit plan trust [2]:				
Equity securities:				
Mutual funds	9	1	—	10
Common stocks	2	—	—	2
Debt securities - mutual funds	2	—	—	2
Assets from price risk management activities [1] [3]:				
Electricity	—	2	—	2
Natural gas	—	7	—	7
	$ 19	$ 41	$ —	$ 60
Liabilities - Liabilities from price risk management activities [1] [3]:				
Electricity	$ —	$ 90	$ 36	$ 126
Natural gas	—	104	113	217
	$ —	$ 194	$ 149	$ 343

(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 $22 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, 2010			
	Level 1	Level 2	Level 3	Total
Assets:				
Nuclear decommissioning trust [1]:				
Money market funds	$ —	$ 13	$ —	$ 13
Debt securities:				
U.S. treasury securities	3	—	—	3
Corporate debt securities	—	6	—	6
Mortgage-backed securities	—	7	—	7
Municipal securities	—	4	—	4
Asset-backed securities	—	1	—	1
Non-qualified benefit plan trust [2]:				
Equity securities:				
Mutual funds	16	1	—	17
Common stocks	2	—	—	2
Debt securities - mutual funds	2	—	—	2
Assets from price risk management activities [1] [3]:				
Electricity	—	4	1	5
Natural gas	—	11	—	11
	$ 23	$ 47	$ 1	$ 71
Liabilities - Liabilities from price risk management activities [1] [3]:				
Electricity	$ —	$ 102	$ 17	$ 119
Natural gas	—	153	104	257
	$ —	$ 255	$ 121	$ 376

(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.

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 levels.

Nuclear decommissioning trust assets reflect the assets held in trust to fund general decommissioning costs and operation of the Independent Spent Fuel Storage Installation (ISFSI) and consist of money market funds and fixed income securities. Non-qualified benefit plan trust reflects the assets held in trust to fund a portion of the obligations of PGE’s non-qualified benefit plans and consist primarily of marketable securities.

Assets and liabilities from price risk management activities represent derivative transactions entered into by PGE to manage its exposure to commodity price risk and reduce exposure to volatility in net power costs for service to the Company’s retail customers. These transactions may consist of forward, swap, and option contracts for electricity, natural gas, oil, and foreign currency, and futures contracts for natural gas and oil. PGE applies a market-based approach to the fair value measurement of its derivative transactions. Inputs into the valuation of derivative activities include forward commodity and foreign exchange pricing, interest rates, volatility and correlation. PGE utilizes the Black-Scholes and Monte Carlo pricing models for commodity option contracts. Forward pricing, which employs the mid-point of the market's bid-ask spread, is derived using observed transactions in active markets, as well as historical experience as a participant in those markets, and is validated against quotes from brokers with whom the Company transacts. Interest rates used to calculate the present value of derivative valuations incorporate PGE's borrowing ability. The Company also considers the liquidity of delivery points of executed transactions when determining where in the fair value hierarchy a transaction should be classified. PGE considers its creditworthiness and the creditworthiness of its counterparties when determining the appropriateness of a particular transaction's assigned Level in the fair value hierarchy.

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, 2011	Nine Months Ended September 30, 2011
Net liabilities from price risk management activities as of beginning of period	$ 127	$ 120
Realized and unrealized losses, net (1)	21	29
Purchases	1	1
Settlements	—	(1)
Net liabilities from price risk management activities as of end of period	$ 149	$ 149

	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2010
Net liabilities from price risk management activities as of beginning of period	$ 225	$ 154
Realized and unrealized losses, net (1)	69	128
Purchases, issuances and settlements, net	1	13
Net liabilities from price risk management activities as of end of period	$ 295	$ 295

(1) Contains nominal amounts of realized losses, net.

The Level 3 net unrealized losses presented in the preceding table are recorded in Purchased power and fuel expense in the condensed consolidated statements of income and have been fully offset by the effects of regulatory accounting. 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. Transfers out of Level 3 occur when the significant inputs become more observable, such as 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.

NOTE 4: PRICE RISK MANAGEMENT

PGE participates in the wholesale marketplace in order to balance its supply of power, which consists of its own generating resources 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 power purchases and sales resulting from economic dispatch decisions for Company-owned generation. As a result of this ongoing business activity, PGE is exposed to commodity price risk and foreign currency exchange rate risk, where adverse changes in prices and/or rates may affect the Company's financial position, results of operations, or cash flow.

PGE utilizes derivative instruments in its wholesale electric utility activities to manage its exposure to commodity price risk and foreign currency exchange rate risk, mitigate the effects of market fluctuations, and reduce exposure to volatility in net power costs for service to its retail customers. These derivative instruments may include forward, swap, and option contracts for electricity, natural gas, oil, and foreign currency, and futures contracts for natural gas and oil and are recorded at fair value on the balance sheet, with changes in fair value recorded in the statement of income. However, as a regulated entity, PGE recognizes a regulatory asset or liability in order to defer gains and losses from derivative activity until realized, in accordance with the ratemaking and cost recovery process authorized by the OPUC. This accounting treatment defers the mark-to-market gains and losses on derivative activities until settlement. PGE may designate certain derivative instruments as cash flow hedges or may use derivative instruments as purely economic hedges. PGE does not engage in trading activities for non-retail purposes.

PGE has elected to report gross on the balance sheet the positive and negative exposures resulting from derivative instruments entered into with counterparties where a master netting arrangement exists. As of September 30, 2011 and December 31, 2010, the Company had $20 million and $31 million, respectively, in collateral posted with these counterparties, consisting entirely of letters of credit.

PGE's net purchase volumes related to its Assets and Liabilities from price risk management activities resulting from its derivative transactions were as follows (in millions):

	September 30, 2011		December 31, 2010	
Commodity contracts:				
Electricity	13	MWh	9	MWh
Natural gas	82	Decatherms	93	Decatherms
Foreign currency	$ 6	Canadian	$ 7	Canadian

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The fair value of PGE's Assets and Liabilities from price risk management activities consists of the following (in millions):

	September 30, 2011	December 31, 2010
Current assets:		
Commodity contracts:		
Electricity	$ 2	$ 4
Natural gas	7	9
Total current derivative assets	9 (1)	13 (1)
Noncurrent assets:		
Commodity contracts:		
Electricity	—	1
Natural gas	—	2
Total noncurrent derivative assets	—	3 (2)
Total derivative assets not designated as hedging instruments	$ 9	$ 16
Total derivative assets	$ 9	$ 16
Current liabilities:		
Commodity contracts:		
Electricity	$ 73	$ 77
Natural gas	123	111
Total current derivative liabilities	196	188
Noncurrent liabilities:		
Commodity contracts:		
Electricity	53	42
Natural gas	94	146
Total noncurrent derivative liabilities	147	188
Total derivative liabilities not designated as hedging instruments	$ 343	$ 376
Total derivative liabilities	$ 343	$ 376

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

Net realized and unrealized losses on derivative transactions not designated as hedging instruments are classified in Purchased power and fuel, net of deferrals related to regulatory accounting, in the condensed consolidated statements of income and were as follows (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Commodity contracts:				
Electricity	$ 44	$ 76	$ 75	$ 135
Natural Gas	30	72	41	181

Net unrealized losses and certain net realized losses presented in the table above are offset within the statements of income by the effects of regulatory accounting. Of the net loss recognized in net income for the three months ended September 30, 2011 and 2010, net losses of $72 million and $146 million, respectively, have been offset, with $107 million and $306 million offset for the nine months ended September 30, 2011 and 2010, 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, 2011 related to PGE's derivative activities would become realized as a result of the settlement of the underlying derivative instrument (in millions):

	2011	2012	2013	2014	2015	Total
Commodity contracts:						
Electricity	$ 21	$ 61	$ 29	$ 11	$ 2	$ 124
Natural gas	33	110	53	13	1	210
Net unrealized loss	$ 54	$ 171	$ 82	$ 24	$ 3	$ 334

The Company'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 the Company's unsecured debt to below investment grade, PGE 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 and 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, 2011 was $276 million, for which the Company has $68 million in posted collateral, consisting entirely of letters of credit. If the credit-risk-related contingent features underlying these agreements were triggered at September 30, 2011, the cash requirement to either post as collateral or settle the instruments immediately would have been $267 million.

Counterparties representing 10% or more of Assets and Liabilities from price risk management activities as of September 30, 2011 or December 31, 2010 were as follows:

	September 30, 2011	December 31, 2010
Assets from price risk management activities:		
Counterparty A	18%	23%
Counterparty B	14	1
Counterparty C	12	5
Counterparty D	9	22
Counterparty E	3	11
Counterparty F	—	10
	56%	72%
Liabilities from price risk management activities:		
Counterparty A	25%	24%
Counterparty G	10	12
	35%	36%

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Numerator (in millions):				
Net income attributable to Portland General Electric Company common shareholders	$ 27	$ 49	$ 118	$ 100
Denominator (in thousands):				
Weighted-average common shares outstanding - basic	75,342	75,295	75,329	75,267
Dilutive effect of unvested restricted stock units and employee stock purchase plan shares	16	16	16	15
Weighted-average common shares outstanding - diluted	75,358	75,311	75,345	75,282
Earnings per share:				
Basic	$ 0.36	$ 0.65	$ 1.57	$ 1.32
Diluted	$ 0.36	$ 0.65	$ 1.57	$ 1.32

Unvested performance stock units and related dividend equivalent rights are not included in the computation of dilutive securities because vesting of these instruments is dependent upon three-year performance periods and the vesting criteria have not been met as of the end of the reporting period presented.

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 months ended September 30, 2011 and 2010 is as follows (dollars in millions):

	Portland General Electric Company Shareholders' Equity				
	Common Stock				
	Shares	Amount	Accumulated Other Comprehensive Loss	Retained Earnings	Noncontrolling Interests' Equity
Balances as of December 31, 2010	75,316,419	$ 831	$ (5)	$ 766	$ 7
Vesting of restricted stock units	15,024	—	—	—	—
Issuance of shares pursuant to employee stock purchase plan	11,320	—	—	—	—
Issuance of shares pursuant to dividend reinvestment and direct stock purchase plan (1)	2,588	—	—	—	—
Stock-based compensation	—	2	—	—	—
Dividends declared	—	—	—	(59)	—
Capital distribution	—	—	—	—	(4)
Net income	—	—	—	118	—
Balances as of September 30, 2011	75,345,351	$ 833	$ (5)	$ 825	$ 3
Balances as of December 31, 2009	75,210,580	$ 829	$ (6)	$ 719	$ 1
Vesting of restricted and performance stock units	73,421	—	—	—	—
Issuance of shares pursuant to employee stock purchase plan	14,846	—	—	—	—
Stock-based compensation	—	1	—	—	—
Dividends declared	—	—	—	(59)	—
Net income (loss)	—	—	—	100	(1)
Other comprehensive income	—	—	1	—	—
Balances as of September 30, 2010	75,298,847	$ 830	$ (5)	$ 760	$ —

(1) Effective April 1, 2011, PGE implemented a Dividend Reinvestment and Direct Stock Purchase Plan, under which the Company may issue up to 2,500,000 shares of common stock.

NOTE 7: COMPREHENSIVE INCOME

Comprehensive income is as follows (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Net income	**$ 27**	**$ 48**	**$ 118**	**$ 99**
Other comprehensive income - Change in compensation retirement benefits liability and amortization, net of taxes	—	1	—	1
Comprehensive income	**27**	**49**	**118**	**100**
Less: comprehensive loss attributable to noncontrolling interests	—	(1)	—	(1)
Comprehensive income attributable to Portland General Electric Company	**$ 27**	**$ 50**	**$ 118**	**$ 101**

Amounts included in Other comprehensive income related to the Company's defined benefit pension plan and other postretirement benefits are reclassified to Regulatory assets as such amounts are expected to be recovered from retail customers in future prices. Accordingly, as of the balance sheet dates, such amounts are included in Regulatory assets. See Note 2.

In 2011, PGE changed the presentation of the Other comprehensive income item 'reclassification of the defined pension plan and other benefits to a regulatory asset or liability' to a net presentation. Accordingly, amounts previously reported on a gross basis for 2010 are presented net to conform with the 2011 presentation.

NOTE 8: 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. The Company records an accrual for such matters when it becomes probable that a loss has occurred and the amount of loss can be reasonably estimated.

When a loss contingency is not both probable and estimable, the Company does not record an accrual. However, if the loss (or an additional loss in excess of an accrual) is at least reasonably possible and material, 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.

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

In 1993, PGE closed the Trojan Nuclear 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. 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.

Regulatory Proceedings. 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 PGE 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 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 refund $15.4 million, plus interest at 9.6% from September 30, 2000, to customers who received service from PGE during the period 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 have separately appealed the 2008 Order to the Oregon Court of Appeals. Those appeals remain pending.

Class Actions. In a separate legal proceeding, two 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 of $260 million, plus interest, as a result of PGE'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 it can offer to PGE customers, through price reductions or refunds, for any amount of return on the Trojan investment PGE collected in prices for the period from April 1, 1995 through October 1, 2000.

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.

Because the above matters involve unsettled legal theories and have a broad range of potential outcomes, management cannot estimate a range of potential loss. Management believes, however, that these matters will not have a material impact on the financial condition of the Company, but may have a material impact on the results of operations and cash flows in future reporting periods.

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 any 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. 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. 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. In its October 2011 Order on Remand, the FERC held the hearing procedures in abeyance pending the results of settlement discussions, which it ordered be convened before a FERC settlement judge. The first settlement conference is scheduled for mid-November 2011.

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.

Management cannot predict whether the FERC will order refunds in the Pacific Northwest Refund proceeding, which contracts would be subject to refunds, or how such refunds, if any, would be calculated. Accordingly, management cannot estimate a range of potential loss. Management believes, however, that the outcome will not have a material impact on the financial condition of the Company, but may have a material impact on PGE's results of operations and cash flows in future reporting periods.

EPA Investigation of Portland Harbor

A 1997 investigation by the EPA of a segment of the Willamette River known as Portland Harbor revealed significant contamination of river sediments. The EPA subsequently included Portland Harbor on the National Priority List pursuant to the federal Comprehensive Environmental Response, Compensation, and Liability Act 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.

The Portland Harbor site is currently undergoing a remedial investigation and feasibility study (RI/FS) pursuant to an Administrative Order on Consent (AOC) between the EPA and several PRPs, not including PGE. In the AOC, the EPA determined that the RI/FS would focus on a segment of the river approximately 5.7 miles in length.

In January 2008, the EPA requested information from various parties, including PGE, concerning properties in or near the 5.7 mile segment of the river being examined in the RI/FS, as well as several miles beyond. Subsequently, the EPA has listed additional PRPs, which now number over one hundred.

The EPA will determine the boundaries of the site at the conclusion of the RI/FS in a Record of Decision in which it will document its findings and select a preferred cleanup alternative. The EPA is not expected to issue the Record of Decision until 2014.

Sufficient information is currently not available to determine either the total cost of any required investigation or remediation of the Portland Harbor site or the liability of PRPs, including PGE. Accordingly, management cannot estimate a range of potential loss. Management believes, however, that the outcome will not have a material impact on the financial condition of the Company, but may have a material impact on PGE's results of operations and cash flows in future reporting periods.

EPA Investigation of Harbor Oil

Harbor Oil, Inc. operated an oil reprocessing business on a site located in north Portland (Harbor Oil) until about 1999. Subsequently, other companies have continued to conduct operations on the site. Until 2003, PGE contracted with the operators of the site to provide used oil from the Company's power plants and electrical distribution system to the operators for use in their reprocessing business. Other entities continue to utilize Harbor Oil for the reprocessing of used oil and other lubricants.

In 1974 and 1979, major oil spills occurred at the Harbor Oil site. Elevated levels of contaminants, including metals, pesticides, and polychlorinated biphenyls, have been detected at the site. In September 2003, the EPA included the Harbor Oil site on the National Priority List as a federal Superfund site.

PGE received a Special Notice Letter for RI/FS from the EPA, dated June 27, 2005, in which the Company was named as one of fourteen PRPs with respect to the Harbor Oil site. In May 2007, an AOC was signed by the EPA and six other parties, including PGE, to implement an RI/FS at the Harbor Oil site. The draft remedial investigation was completed with the resulting report submitted to the EPA. The EPA has not yet issued a response.

Sufficient information is currently not available to determine the total cost of investigation and remediation of the Harbor Oil site or the liability of the PRPs, including PGE. Accordingly, management cannot estimate a range of potential loss. Management believes, however, that the outcome of this matter will not have a material impact on the financial condition of the Company, but may have a material impact on PGE's results of operations and cash flows in future reporting periods.

Revenue Bonds

In 2008, PGE repurchased $5.8 million of Pollution Control Revenue Bonds Series 1996 (Bonds) issued through the Port of Morrow. In connection with the repurchase, PGE paid the $5.8 million repurchase price to Lehman Brothers Inc. (Lehman) as remarketing agent for the Bonds, who in turn paid off the beneficial owner of the Bonds. As a result of the payment, PGE became the beneficial owner of the Bonds and requested that Lehman safe-keep the Bonds in Lehman’s Depository Trust Company participant account until such time as the Bonds could be remarketed. After repurchase of the Bonds, PGE removed the liability for the Bonds from its financial statements.

In September 2008, Lehman filed for protection under Chapter 11 of the U.S. Bankruptcy Code. PGE subsequently filed a claim for return of the Bonds from Lehman. In November 2009, the trustee appointed to liquidate the assets of Lehman (Trustee) allowed PGE’s claim as a net equity claim for securities. At the time, PGE believed it would receive back the entire amount of the Bonds at some point during the bankruptcy proceedings.

It is not certain that the Company will receive the full amount of the Bonds but could, along with other claimants, potentially receive a pro-rata share of certain assets. The timing and extent of distributions on claims are subject to the ultimate disposition of numerous claims in the proceedings and certain major contingencies which the Trustee must resolve. PGE cannot currently estimate how much of the value of the Bonds will ultimately be returned to the Company or the timing of the distribution from Lehman. Management does not expect the outcome of this matter to have a material impact on the Company’s financial condition, but it may have a material impact on PGE’s results of operations and cash flows in a future interim reporting period.

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 its business, which may result in judgments against the Company. Although management currently believes that resolution of such matters will not have a material effect 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 9: 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 PGE’s historical experience and the evaluation of the specific indemnities. As of September 30, 2011, 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 10: 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. The Company 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 PGE 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, 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 the expected losses of the LLCs.

Included in PGE's condensed consolidated balance sheet are LLC net assets as follows (in millions):

	September 30, 2011	December 31, 2010
Cash and cash equivalents	$ 1	$ 1
Accounts receivable, net	—	4
Electric utility plant, net	5	5

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 PGE to have a reasonable basis including, but not limited to, management’s examination of historical operating trends and data contained in records and other data available from third parties, but there can be no assurance that PGE’s expectations, beliefs or projections will be achieved or accomplished.

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

- governmental policies and regulatory audits, investigations and actions, including those of the FERC and OPUC with respect to allowed rates of return, financings, electricity pricing and price structures, acquisition and disposal of facilities and other assets, construction and operation of plant facilities, transmission of electricity, recovery of power costs and capital investments, and current or prospective wholesale and retail competition;
- the effects of weak economies in the state of Oregon and the United States, including decreased demand for electricity, reduced revenue from sales of excess energy during periods of low wholesale market prices, impaired financial stability of vendors and service providers and elevated levels of uncollectible customer accounts;
- the outcome of legal and regulatory proceedings and issues including, but not limited to, the matters described in Note 8, Contingencies, in the Notes to Condensed Consolidated Financial Statements;
- unseasonable or extreme weather and other natural phenomena, which can affect customers’ demand for power and could significantly affect PGE’s ability and cost to procure adequate power and fuel supplies to serve its customers, and could increase the Company’s costs to maintain its generating facilities and transmission and distribution systems;
- operational factors affecting PGE’s power 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;
- 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;
- capital market conditions, including access to capital, interest rate volatility, reductions in demand for investment-grade commercial paper and the availability and cost of capital, 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 costs, and the repayments of maturing debt;

- 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 pollution control equipment 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;
- changes in wholesale prices for natural gas, coal, oil, and other fuels and the impact of such changes on the Company’s power costs and the availability and price of wholesale power in the western United States;
- changes in residential, commercial, and industrial growth, and in demographic patterns, in PGE’s service territory;
- the effectiveness of PGE’s risk management policies and procedures and the creditworthiness of customers and counterparties;
- the failure to complete capital projects on schedule and within budget;
- declines in the fair value of equity securities held by 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 that 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;
- employee workforce factors, including aging, potential strikes, work stoppages, and transitions in senior management;
- cyber security attacks, data security breaches, or other malicious acts that cause damage to the Company’s generation and transmission facilities, information technology systems, or result in the release of confidential customer and proprietary information;
- general political, economic, and financial market conditions;
- natural disasters and other risks, such as earthquake, flood, drought, 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, 2010, and other periodic and current reports filed with the SEC.

Operating Activities — PGE is a vertically integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the state of Oregon, as well as the wholesale sale of electricity and natural gas in the United States and Canada. The Company generates revenues and cash flows primarily from the sale and distribution of electricity to customers in its service territory.

The Company's revenues and income from operations can fluctuate from period to period based on numerous factors including seasonal weather conditions and the resulting demand for electricity, retail and wholesale price changes, customer usage patterns (which can be affected by the economy), and the availability and price of purchased power and fuel. PGE is a winter-peaking utility that typically experiences its highest retail energy sales during the winter heating season, with a slightly lower peak in the summer that generally results from air conditioning demand.

Customers and Demand — Retail energy deliveries for the nine months ended September 30, 2011 increased 4.4% from the comparable period of 2010. On a weather adjusted basis, energy deliveries to retail customers for the nine months ended September 30, 2011 increased 2.0%, due to the effects of production increases by paper and high tech industrial customers and an increase in the average number of customers served of approximately 3,100. Seasonally adjusted unemployment rates during the third quarter of 2011 averaged approximately 9.6% in the Portland/Salem region.

The following table presents deliveries, by customer class, including those to customers who chose to purchase their energy from an Electricity Service Supplier (ESS), for the periods indicated:

	Nine Months Ended September 30,				
	2011		2010		
	Average Number of Customers	Energy Deliveries *	Average Number of Customers	Energy Deliveries *	Increase in Energy Deliveries
Residential	719,809	5,604	717,357	5,357	4.6%
Commercial	102,911	5,560	102,255	5,428	2.4
Industrial	255	3,156	267	2,927	7.8
Total	822,975	14,320	819,879	13,712	4.4

* In thousands of MWh.

PGE projects that weather adjusted retail energy deliveries for 2011 will be approximately 1.5% above 2010 levels, including the anticipated effects of energy efficiency measures. The increase in deliveries reflects expected growth in commercial and industrial deliveries, particularly from paper production customers. The variability in deliveries from period to period may be impacted by qualifying customers who obtain their incremental energy requirements at market prices. As a result, their production levels and corresponding energy requirements can vary based on market conditions. Excluding such paper production customers, retail energy deliveries on a weather adjusted basis for 2011 are expected to be approximately 0.6% higher than 2010.

Power Operations — To meet the energy needs of its customers, the Company utilizes a combination of its own generating resources and wholesale market transactions. Based on numerous factors, including plant availability, customer demand, and current wholesale prices, PGE makes economic dispatch decisions continuously throughout a given period in an effort to minimize power costs 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 second quarters of 2011 and 2010, such annual maintenance was performed, with more extensive planned service maintenance completed in 2011 compared to 2010. The work at Boardman included the first of planned emissions controls that are expected to reduce nitrogen oxides by 50%, mercury by 90%, and permitted sulfur dioxide by 75%. At Coyote Springs, the Company replaced the cooling tower structure and upgraded the gas turbine and exhaust system components, increasing the plant's output and efficiency. Availability of the plants PGE operates approximated 92% and 94% for the nine months ended September 30, 2011 and 2010, respectively, with the availability of Colstrip, which PGE does not operate, approximating 80% and 96%, respectively. The decrease in Colstrip's availability in 2011 is due to the plant's planned maintenance, which included the installation of a new rotor for Unit 3.

During the nine months ended September 30, 2011, the Company's generating plants provided approximately 44% of its retail load requirement, compared to 64% in the nine months ended September 30, 2010. Although the level of service maintenance on the Company's generating plants was greater in 2011 than in 2010, the decrease in the relative volume of power generated to meet the Company's retail load requirement was primarily due to the economic displacement of a significant amount of thermal generation by lower cost purchased power during the nine months ended September 30, 2011.

Energy received from PGE-owned hydroelectric plants and under contracts from mid-Columbia hydroelectric projects increased 26% in the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010. These resources provided approximately 28% of the Company's retail load requirement for the nine months ended September 30, 2011, compared to 23% for the nine months ended September 30, 2010. Energy received from these sources exceeded projections (or 'normal') included in the Company's Annual Power Cost Update Tariff (AUT) by approximately 17% during the nine months ended September 30, 2011, compared to falling short of such projections by approximately 10% during the nine months ended September 30, 2010. 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. 'Normal' represents the level of energy forecasted to be received from hydroelectric resources for the year and is based 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 exceed normal for 2011.

Pursuant to the Company's power cost adjustment mechanism (PCAM), customer prices can be adjusted to reflect a portion of the difference between each year's forecasted net variable power costs (NVPC) included in prices (baseline NVPC) and actual NVPC for the year, to the extent such difference is outside of a pre-determined "deadband." The PCAM provides for 90% of actual NVPC above or below the deadband to be collected from or refunded to customers, respectively, subject to a regulated earnings test. Any estimated collection from or refund to customers pursuant to the PCAM is recorded in Revenues in the Company's statements of income in the period of accrual. The deadband ranges from $15 million below to $30 million above baseline NVPC for 2011 and ranged from $17 million below to $35 million above baseline NVPC for 2010.

For the nine months ended September 30, 2011, actual NVPC was approximately $36 million below baseline NVPC, which is $21 million below the lower deadband threshold of $15 million. As forecasted NVPC for the year ending December 31, 2011 is currently estimated to be below the baseline NVPC and the lower deadband threshold, with the Company expecting to exceed its regulated earnings test, PGE has recorded an estimated refund to customers of approximately $17 million as of September 30, 2011. The recorded amount reflects a $2 million reduction from the $19 million potential refund to customers as the result of the regulated earnings test. For the nine months ended September 30, 2010, actual NVPC was approximately $11 million below baseline NVPC, with no refund to customers recorded as actual NVPC was within the established deadband range.

Capital Requirements and Financing — PGE's capital requirements for 2011 are related primarily to ongoing expenditures for the upgrade, replacement, and expansion of transmission, distribution, and generation infrastructure, as well as technology enhancements and expenditures related to hydro licensing and construction. Capital expenditures are expected to approximate $304 million in 2011, of which $215 million was incurred through September 30. For further information, see the Capital Requirements section of Liquidity and Capital Resources in this Item 2.

For 2011, the Company expects to meet capital requirements with cash from ongoing operations, with no issuances of long-term debt or equity. In subsequent years, the Company expects to fund its capital requirements with a combination of cash from operations and funds from the capital markets as internal liquidity needs and market conditions warrant. The Company also expects that the borrowing capacity under its credit facilities will continue to be available to manage working capital requirements during those periods. For further information, see the Debt and Equity Financings section of Liquidity and Capital Resources in this Item 2.

PGE's 2009 Integrated Resource Plan (IRP), acknowledged by the OPUC in November 2010, includes the Company's strategy for acquiring new resources over the next several years and a 20-year strategy outlining long-term expectations for resource needs and portfolio management. To meet projected energy requirements, the IRP includes energy efficiency measures, additional renewable resources, new transmission capability, new generation, and improvements to existing generating plants.

In accordance with the IRP acknowledgement and pursuant to the OPUC's competitive bidding guidelines, the Company plans to implement the IRP by issuing requests for proposals (RFPs) for additional resources. On September 27, 2011, the OPUC issued an order that directed PGE to combine its requests for capacity and energy resources into a single RFP.

The Company now anticipates issuing two RFPs in 2012 as follows:

The first RFP would seek approximately:

- 300 to 500 MW of base load energy resources;
- 200 MW of year-round flexible and peaking resources to help supply customers with electricity during peak demand periods and integrate increasing system levels of variable energy resources such as wind and solar power;
- 200 MW of bi-seasonal (winter and summer) peaking supply; and
- 150 MW of winter-only peaking supply.

The second RFP would seek approximately 120 MWa of renewable resources.

The flexible and peaking resources would be expected to be available in the 2013 to 2015 time frame with the base load energy resources expected to be available in the 2015 to 2017 time frame. The renewable resources are anticipated to be in service to meet PGE's 2015 requirements under Oregon's renewable energy standard. PGE expects to submit self-build proposals in each competitive bidding process for new resources.

The IRP includes a proposal for an approximately 210-mile, 500 kV transmission line referred to as the Cascade Crossing Transmission Project, or Cascade Crossing. By interconnecting new and existing energy resources in eastern Oregon to the Company's service territory, Cascade Crossing would help meet future electricity demand and improve grid reliability. PGE continues to work with other stakeholders in the region in planning the project and is actively engaged in the federal, state, and tribal permitting processes. Subject to obtaining all necessary approvals, the expected in-service date would be late 2016 or 2017. In October 2011, Cascade Crossing was selected as one of seven transmission projects in the nation to participate in the federal inter-agency Rapid Response Team for Transmission program to improve agency collaboration and streamline federal permitting.

For additional information, see the Capital Requirements section of Liquidity and Capital Resources in this Item 2.

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, matters related to:

- 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 8, Contingencies, in the Notes to Condensed Consolidated Financial Statements.

Certain regulatory items, including those discussed below, have impacted the Company's revenues, results of operations, or cash flows for the nine months ended September 30, 2011. In some cases, retail customer prices were affected, as authorized by the OPUC, while in other instances, the Company may have 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.

- General Rate Case — Effective January 1, 2011, the OPUC approved an increase in PGE's annual revenues of $65 million, which represented an approximate 3.9% overall increase in customer prices, and included a reduction in NVPC of $35 million.

  The OPUC also approved a tariff that provides a mechanism for future consideration of customer price changes related to the recovery of the Company's remaining investment in the Boardman generating plant over a shortened operating life. The Company plans to cease coal-fired operation at Boardman at the end of 2020, consistent with revised rules adopted by the Oregon Environmental Quality Commission in December 2010 and approved by the EPA in June 2011.

  Pursuant to the tariff, the OPUC approved recovery of increased depreciation expense reflecting a change in the retirement date of Boardman from 2040 to 2020, with new prices effective July 1, 2011, which provides an incremental revenue requirement for the last six months of 2011 estimated at approximately $8 million. The tariff provides for annual updates to the revenue requirements with revised prices to take effect each January 1.

- Power Costs — Pursuant to the AUT process, PGE annually files an estimate of power costs for the following year. On November 2, 2011, the OPUC issued an order on the 2012 AUT resulting in an estimated 1% decrease in customer prices. The new prices will be finalized in mid-November and will become effective January 1, 2012.

- 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. The Company did not submit a RAC filing in April 2011 as it does not anticipate an approved renewable resource addition would be placed into service during 2011.

  Under the RAC, in 2010, PGE filed for recovery of, among other things, the deferral of eligible costs and a return on its investment related to Biglow Canyon Phase III. The OPUC approved recovery over a one-year period beginning January 1, 2011 of $22.1 million, which includes a residual balance from the deferral of Biglow Canyon Phase II. In addition, effective January 1, 2011, the annual revenue requirement related to the investment in Biglow Canyon Phase III is reflected in retail prices through the Company’s 2011 General Rate Case.

- Regulatory Treatment of Income Taxes — In April 2011, the OPUC issued its order on the Company’s 2009 SB 408 report, authorizing the previously stipulated refund to customers of $9 million, including interest, over a one-year period beginning June 1, 2011.

  In May 2011, Oregon Senate Bill 967 (SB 967) was enacted, which repealed previously existing statutes governing the adjustment of public utility rates to account for differences between taxes paid by electricity and natural gas utilities and amounts collected from customers for taxes (collectively referred to as SB 408). Among other matters, SB 967 requires the OPUC to consider taxes paid by electricity and natural gas utilities when conducting ratemaking proceedings.

  As SB 967 is effective beginning with the annual filing pertaining to 2010, no annual SB 408 reports or corresponding rate adjustments will be required under the new law for 2010 and subsequent years.

  At the time of the enactment of SB 967 in 2011, the Company had nominal accrued amounts related to SB 408.

- Decoupling — The decoupling mechanism is intended to provide for recovery of reduced revenues resulting from a reduction in electricity sales attributable to energy efficiency and conservation efforts by residential and certain commercial customers. The mechanism provides for customer collection (or refund) if weather adjusted use per customer is less than (or more than) the levels approved in the Company’s most recent general rate case.
  - During the nine months ended September 30, 2011, PGE recorded a nominal estimated collection.
  - For 2010, the Company recorded an estimated collection of $8 million, as weather adjusted use per customer was less than levels included in the 2009 General Rate Case. After review, the OPUC approved collections from customers over a one-year period that began June 1, 2011.

- Refund of tax credits — In January 2011, PGE began providing credits to customers over a one year period for tax credits the Company had accumulated related to the Independent Spent Fuel Storage Installation (ISFSI). For the nine months ended September 30, 2011, the Company has provided $13 million in customer credits.

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, 2010, filed with the SEC on February 25, 2011.

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,			
	2011		2010		2011		2010	
Revenues, net	$ 439	100 %	$ 464	100%	$ 1,334	100 %	$ 1,328	100%
Purchased power and fuel	182	41	203	44	545	41	613	46
Gross margin	257	59	261	56	789	59	715	54
Operating expenses:								
Production and distribution	50	11	42	9	147	11	127	9
Administrative and other	55	13	47	10	158	12	140	11
Depreciation and amortization	59	13	59	13	170	13	173	13
Taxes other than income taxes	25	6	23	5	74	5	67	5
Total operating expenses	189	43	171	37	549	41	507	38
Income from operations	68	16	90	19	240	18	208	16
Other income (expense):								
Allowance for equity funds used during construction	1	—	4	1	3	—	12	1
Miscellaneous income (expense), net	(4)	(1)	3	1	(1)	—	1	—
Other income (expense), net	(3)	(1)	7	2	2	—	13	1
Interest expense	27	6	27	6	82	6	82	6
Income before income taxes	38	9	70	15	160	12	139	11
Income taxes	11	3	22	5	42	3	40	3
Net income	27	6	48	10	118	9	99	8
Less: net loss attributable to noncontrolling interests	—	—	(1)	—	—	—	(1)	—
Net income attributable to Portland General Electric Company	$ 27	6 %	$ 49	10%	$ 118	9 %	$ 100	8%

Net income attributable to Portland General Electric Company was $27 million, or $0.36 per diluted share, for the third quarter of 2011 compared to $49 million, or $0.65 per diluted share, for the third quarter of 2010. A $20 million estimated collection from customers recorded in the third quarter of 2010 related to the regulatory treatment of income taxes (which was reversed in the fourth quarter of 2010), and a $4 million loss related to a decrease in the fair value of non-qualified benefit plan assets in the third quarter of 2011 compared to a $3 million gain recorded in the third quarter of 2010, along with higher operating costs all contributed to the $22 million decrease in net income.

The items above were partially offset by the combination of a 12% decrease in average variable power cost and a 4% increase in customer prices. The decrease in average variable power cost resulted from a 28% decline in the average price of purchased power and a 24% increase in energy from hydro resources in the third quarter of 2011 relative to the third quarter of 2010. During the third quarter of 2011, a significant amount of thermal generation was economically displaced with lower-cost power purchased in the wholesale market and increased hydro and wind generation. The favorable hydro conditions during the third quarter of 2011 resulted in a 16% increase from normal in power received from hydro resources, compared to 9% below normal during the third quarter of 2010.

Net income attributable to Portland General Electric Company was $118 million, or $1.57 per diluted share, for the nine months ended September 30, 2011 compared to $100 million, or $1.32 per diluted share, for the nine months ended September 30, 2010. The $18 million increase in net income was largely driven by the combination of a 13% decrease in average variable power cost, a 4% increase in total retail energy deliveries and a 3% increase in customer prices. Decreased average variable power cost was driven by the economic displacement of a significant amount of thermal generation with lower-cost purchased power and increased energy received from hydro and wind resources. As a result of decreased NVPC, PGE recorded an estimated refund to customers of $17 million pursuant to the PCAM, as actual NVPC was below baseline NVPC for the nine months ended September 30, 2011, with no refund to or collection from customers recorded in the comparable period of 2010. Increased retail energy deliveries were driven by cooler temperatures in the nine months ended September 30, 2011 relative to the comparable period of 2010 and increased production by certain customers in the paper production and high technology sectors.

The above items were partially offset by the impacts from a $26 million estimated collection from customers related to the regulatory treatment of income taxes and an $8 million estimated collection from customers related to the decoupling mechanism, both recorded in 2010, as well as increased plant maintenance expenses and incentive compensation in 2011, all of which are discussed further in the Nine Months Ended September 30, 2011 Compared to the Nine Months Ended September 30, 2010 section of this Item 2.

Third Quarter of 2011 Compared to the Third Quarter of 2010

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

	Three Months Ended September 30,			
	2011		2010	
Revenues (1) (dollars in millions):				
Retail:				
Residential	$ 184	42 %	$ 176	38%
Commercial	167	38	158	34
Industrial	59	14	57	12
Subtotal	410	94	391	84
Other - accrued revenues	(4)	(1)	36	8
Total retail revenues	406	93	427	92
Wholesale revenues	24	5	27	6
Other operating revenues	9	2	10	2
Total revenues	$ 439	100 %	$ 464	100%
Energy deliveries (2) (MWh in thousands):				
Retail:				
Residential	1,598	30 %	1,626	30%
Commercial	1,970	36	1,950	37
Industrial	1,089	20	1,045	20
Total retail energy deliveries	4,657	86	4,621	87
Wholesale energy deliveries	780	14	721	13
Total energy deliveries	5,437	100 %	5,342	100%
Average number of retail customers:				
Residential	719,978	87 %	718,226	87%
Commercial	104,471	13	103,759	13
Industrial	253	—	261	—
Total	824,702	100 %	822,246	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 $25 million, or 5%, in the third quarter of 2011 compared to the third quarter of 2010 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 from ESSs. Retail revenues also include certain accrued revenues, comprised primarily of deferrals of amounts related to the PCAM, SB 408, the decoupling mechanism, and the RAC filings.

Total retail revenues decreased $21 million, or 5%, in the third quarter of 2011 compared to the third quarter of 2010, primarily due to the net effect of the following:

- A $20 million decrease related to the regulatory treatment of income taxes under SB 408, included in Other - accrued revenues, resulting primarily from an estimated collection recorded in the third quarter of 2010, which was reversed in the fourth quarter of 2010. For further information on the regulatory treatment of income taxes, see Legal, Regulatory and Environmental Matters in the Overview section of this Item 2;

- An $8 million decrease related to the accrual of revenue requirements for Biglow Canyon under the RAC in the third quarter of 2010;
- A $6 million decrease as a result of the 2010 reversal of a liability related to the 2005 Oregon Tax Kicker, included in Other - accrued revenues;
- A $4 million decrease related to an estimated future refund to customers, pursuant to the PCAM, recorded in the third quarter of 2011 and included in Other - accrued revenues. No amounts related to the PCAM were recorded in the third quarter of 2010. For further discussion of the PCAM, see the Purchased Power and Fuel section, below;
- A $14 million increase related to changes in the average retail price, resulting primarily from the 3.9% overall increase January 1, 2011 authorized by the OPUC in the Company's 2011 General Rate Case, and an increase that went into effect July 1, 2011 for the recovery of Boardman over a shortened operating life; and
- A $5 million increase as a result of a greater volume of energy sold. Commercial and industrial deliveries combined were up 2% due to increased production by certain customers in the paper production sector and an increase of 700 in the average number of customers, which was partially offset by a 2% decrease in average energy use per residential customer.

Heating and cooling degree-days are an indication of the likelihood that customers will use heating and cooling, respectively, and are used to measure the effects of weather on the demand for electricity, with temperature variations generally having the greatest impact on residential demand. Total heating and cooling degree days in 2011 were 4% lower than 2010 levels and 17% lower than historical averages.

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**	
	2011	**2010**	**2011**	**2010**
July	13	37	72	120
August	2	26	160	131
September	36	54	114	45
3rd quarter	51	117	346	296
15-year average for the quarter	87	82	393	398

On a weather adjusted basis, energy deliveries to retail customers increased by 0.7% in the third quarter of 2011 compared to the third quarter of 2010, resulting primarily from higher demand by paper production customers.

Wholesale revenues result from sales of electricity to utilities and power marketers that are made in conjunction with the Company's effort to secure reasonably priced power for retail customers, manage risk, and administer long-term wholesale contracts. Such sales can vary significantly period to period. Wholesale revenues in the third quarter of 2011 declined $3 million, or 11%, compared to the third quarter of 2010, as the result of the somewhat offsetting effects of a 17% decrease in average price resulting from lower wholesale market prices driven by increased regional hydro production and an 8% increase in sales volume.

Purchased power and fuel expense decreased $21 million, or 10%, in the third quarter of 2011 compared to the third quarter of 2010, with $26 million related to a 12% decrease in average variable power cost partially offset by $5 million related to a 2% increase in total system load. The average variable power cost decreased to $33.49 per MWh in the third quarter of 2011 compared to $38.12 per MWh in the third quarter of 2010.

The decrease in Purchased power and fuel expense consisted of:

- A $20 million decrease in the cost of generation, primarily driven by a decrease in the proportion of power provided by Company-owned thermal generating resources. During the third quarter of 2011, thermal generation was economically displaced by purchased power and increased energy from hydro and wind generating resources relative to the third quarter of 2010. The average cost of power generated decreased 1% in the third quarter of 2011 compared to the third quarter of 2010; and
- A $1 million decrease in the cost of purchased power, consisting of $41 million related to a 28% decrease in average cost, substantially offset by $40 million related to a 38% increase in total energy purchases. The decrease in average cost was primarily driven by lower wholesale power prices resulting from favorable hydro conditions.

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

	Three Months Ended September 30,			
	2011		2010	
Sources of energy (MWh in thousands):				
Generation:				
Thermal:				
Coal	1,200	22%	1,374	26%
Natural gas	723	13	1,279	24
Total thermal	1,923	35	2,653	50
Hydro	345	6	338	6
Wind	379	7	301	6
Total generation	2,647	48	3,292	62
Purchased power:				
Term	1,337	25	491	9
Hydro	766	14	558	10
Wind	95	2	84	2
Spot	617	11	911	17
Total purchased power	2,815	52	2,044	38
Total system load	5,462	100%	5,336	100%
Less: wholesale sales	(780)		(721)	
Retail load requirement	4,682		4,615	

Energy from PGE-owned wind generating resources (Biglow Canyon) increased 26%, and represented 8% of the Company's retail load requirement in the third quarter of 2011, compared to 7% in the third quarter of 2010. The increase was due to the completion of the third and final phase of Biglow Canyon in August 2010 and favorable wind conditions in 2011.

Hydroelectric energy during the third quarter of 2011, from both PGE-owned plants and from mid-Columbia projects, exceeded both normal levels and the third quarter of 2010 by 16% and 24%, respectively. Total hydroelectric energy in the third quarter of 2010 was 9% below normal. Energy from hydro resources is expected to exceed normal for 2011.

The following table presents the forecast of the April-to-September 2011 runoffs (issued July 8, 2011, with the final update expected in December 2011) at particular points of major rivers relevant to PGE's hydro resources, with actual runoffs for 2010 (as a percentage of normal, as measured over the 30-year period from 1971 through 2000):

	Runoff as a Percent of Normal *	
Location	**2011 Forecast**	**2010 Actual**
Columbia River at The Dalles, Oregon	138%	79%
Mid-Columbia River at Grand Coulee, Washington	128	78
Clackamas River at Estacada, Oregon	138	124
Deschutes River at Moody, Oregon	116	104

* Volumetric water supply forecasts 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.

For the third quarter of 2011, actual NVPC was approximately $7 million below baseline NVPC, with PGE recording an estimated refund to customers of approximately $4 million. Actual NVPC was approximately $2 million below baseline NVPC in the third quarter of 2010, but within the established deadband range; accordingly, no refund to customers was recorded.

Gross margin, which represents the difference between Revenues, net and Purchased power and fuel expense, is among those performance indicators utilized by management in the analysis of financial and operating results and is intended to supplement the understanding of PGE's operating performance. It provides a measure of income available to support other operating activities and expenses of the Company and serves as a useful measure for understanding and analyzing changes in operating performance between reporting periods. It is considered a "non-GAAP financial measure," as defined in accordance with SEC rules, and is not intended to replace operating income as determined in accordance with GAAP.

Gross margin was 59% in the third quarter of 2011, compared to 56% in the third quarter of 2010. The increase in Gross margin was driven by the 12% decrease in average variable power cost and an increase in retail customer prices resulting from the 2011 General Rate Case, which became effective January 1, 2011, and a tariff for the recovery of Boardman over a shortened operating life, which became effective July 1, 2011.

Production and distribution expense increased $8 million, or 19%, in the third quarter of 2011 compared to the third quarter of 2010 primarily due to increases in operating and maintenance expenses at the Company's thermal generating plants. Also contributing to the increase were higher delivery system expenses, including those related to tree trimming activities.

Administrative and other expense increased $8 million, or 17%, in the third quarter of 2011 compared to the third quarter of 2010. The increase was primarily due to higher employee benefit expenses and increased incentive compensation, related to an improvement in projected corporate financial performance for 2011, as well as an increase in legal fees.

Depreciation and amortization expense in the third quarter of 2011 was comparable to the third quarter of 2010. A $3 million increase related to Biglow Canyon Phase III, a shorter operating life for the Boardman plant, and the smart meter project was offset by a $4 million decrease related to the amortization of customer refunds of certain Oregon tax credits (offset in Revenues).

Taxes other than income taxes increased $2 million, or 9%, in the third quarter of 2011 compared to the third quarter of 2010, which was primarily due to higher property taxes, resulting from both increased property values and tax rates.

Other income (expense), net was $(3) million in the third quarter of 2011 compared to $7 million in the third quarter of 2010. During the third quarter of 2011, a $4 million loss was recorded related to a decrease in the fair value of the non-qualified benefit plan trust assets, compared to a $3 million gain recorded in the third quarter of 2010. Additionally, the allowance for equity funds used during construction decreased approximately $3 million as a result of lower construction work in progress balances during the third quarter of 2011, primarily due to the completion of Phase III of Biglow Canyon in August 2010.

Interest expense in the third quarter of 2011 was comparable to the third quarter of 2010, as a $2 million decrease in the credit for allowance for funds used during construction, related primarily to the completion of Biglow Canyon Phase III, was offset by lower interest related to certain regulatory liabilities.

Income taxes decreased $11 million in the third quarter of 2011 compared to the third quarter of 2010 primarily due to a decrease in pre-tax income. The effective tax rates (approximately 28.9% and 31.4% in the third quarters of 2011 and 2010, respectively) are lower than the federal statutory rate primarily due to benefits from federal wind production tax credits, related to increased generation from Biglow Canyon, and state tax credits.

Nine Months Ended September 30, 2011 Compared to the Nine Months Ended September 30, 2010

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

	Nine Months Ended September 30,			
	2011		2010	
Revenues [(1)] (dollars in millions):				
Retail:				
Residential	$ 635	46 %	$ 578	43%
Commercial	474	36	447	34
Industrial	168	13	161	12
Subtotal	1,277	95	1,186	89
Other - accrued revenues	(18)	(1)	47	4
Total retail revenues	1,259	94	1,233	93
Wholesale revenues	49	4	69	5
Other operating revenues	26	2	26	2
Total revenues	$ 1,334	100 %	$ 1,328	100%
Energy deliveries [(2)] (MWh in thousands):				
Retail:				
Residential	5,604	35 %	5,357	34%
Commercial	5,560	34	5,428	34
Industrial	3,156	20	2,927	19
Total retail energy deliveries	14,320	89	13,712	87
Wholesale energy deliveries	1,848	11	2,115	13
Total energy deliveries	16,168	100 %	15,827	100%
Average number of retail customers:				
Residential	719,809	87 %	717,357	88%
Commercial	102,911	13	102,255	12
Industrial	255	—	267	—
Total	822,975	100 %	819,879	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 increased $6 million for the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010.

Retail revenues increased $26 million, or 2%, in the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010, primarily due to the net effect of the following:

- A $58 million increase as a result of a higher volume of energy sold. Residential volumes increased 4.6%, primarily driven by the impact of cooler temperatures and a 2,500 increase in the average number of customers. Commercial and industrial deliveries combined were up 4.3% due to increased production by certain customers in the paper sector, increases from the technology sector, and a 600 increase in the average number of customers;
- A $37 million increase related to changes in the average retail price, resulting primarily from the 3.9% overall increase January 1, 2011 authorized by the OPUC in the Company's 2011 General Rate Case and an increase related to the recovery of Boardman over a shortened operating life;

- A $26 million decrease related to the regulatory treatment of income taxes under SB 408 that was in place during 2010, which is included in Other - accrued revenues. An estimated collection was recorded in the nine months ended September 30, 2010. That amount was reversed in the fourth quarter of 2010;
- A $17 million decrease related to an estimated refund to customers, pursuant to the PCAM, recorded in the nine months ended September 30, 2011 and included in Other - accrued revenues. No amounts were recorded in the nine months ended September 30, 2010. For further discussion of the PCAM, see the Purchased Power and Fuel section, below;
- A $13 million decrease as a result of the ISFSI tax credits refund recorded in 2011, with no comparable refund in place in 2010 (offset in Depreciation and amortization);
- An $8 million decrease related to the decoupling mechanism, as an $8 million collection from customers was recorded in the nine months ended September 30, 2010 compared to a minor collection recorded in 2011, which is included in Other - accrued revenues; and
- A $6 million decrease as a result of the 2010 reversal of a liability related to the 2005 Oregon Tax Kicker.

Heating degree-days during the nine months ended September 30, 2011 were 14% higher than in the comparable period of 2010 and 13% above the 15-year average. The majority of the difference between 2011 and 2010 was driven by cooler than average temperatures in 2011, which has increased the demand for electricity in 2011.

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**	
	2011	**2010**	**2011**	**2010**
1st Quarter	1,974	1,629	—	—
2nd Quarter	946	861	16	18
3rd Quarter	51	117	346	296
Year-to-date	2,971	2,607	362	314
15-year average for the year-to-date	2,630	2,615	462	471

On a weather adjusted basis, energy deliveries to retail customers increased by 2.0% in the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010.

Wholesale revenues in the nine months ended September 30, 2011 declined $20 million, or 29%, compared to the nine months ended September 30, 2010, primarily as the result of the combined effect of a 21% average price decrease resulting from lower wholesale market prices, and a 13% reduction in sales volume.

Purchased power and fuel expense decreased $68 million, or 11%, in the nine months ended September 30, 2011, compared to the nine months ended September 30, 2010, with $80 million related to a 13% decrease in average variable power cost, partially offset by $13 million related to a 2% increase in total system load. The average variable power cost decreased to $33.58 per MWh for the nine months ended September 30, 2011 compared to $38.49 per MWh for the nine months ended September 30, 2010.

The decrease in Purchased power and fuel expense primarily consisted of:

- A $69 million decrease in the cost of generation, primarily driven by a decrease in the proportion of power provided by Company-owned thermal generating resources. During the nine months ended September 30, 2011, more thermal generation was economically displaced by purchased power and increased energy from hydro and wind generating resources relative to the nine months ended September 30, 2010. The average cost of power generated in the nine months ended September 30, 2011 was comparable to that in the nine months ended September 30, 2010; partially offset by
- A $2 million increase in the cost of purchased power, consisting of $145 million related to a 39% increase in total energy purchases, largely offset by $143 million related to a 28% decrease in average cost. The decrease in average cost was primarily driven by lower wholesale power prices resulting from favorable hydro conditions.

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

	Nine Months Ended September 30,			
	2011		2010	
Sources of energy (MWh in thousands):				
Generation:				
Thermal:				
Coal	2,708	17%	3,604	22%
Natural gas	1,058	6	3,164	20
Total thermal	3,766	23	6,768	42
Hydro	1,524	10	1,355	9
Wind	1,025	6	662	4
Total generation	6,315	39	8,785	55
Purchased power:				
Term	5,057	31	2,960	19
Hydro	2,489	15	1,824	12
Wind	203	1	234	1
Spot	2,200	14	2,127	13
Total purchased power	9,949	61	7,145	45
Total system load	16,264	100%	15,930	100%
Less: wholesale sales	(1,848)		(2,115)	
Retail load requirement	14,416		13,815	

Energy from PGE-owned wind generating resources (Biglow Canyon) increased 55%, and represented 7% of the Company's retail load requirement in the nine months ended September 30, 2011, compared to 5% in the nine months ended September 30, 2010. The increase was due to the completion of the third and final phase of Biglow Canyon in August 2010, and favorable wind conditions in 2011.

Hydroelectric energy during the nine months ended September 30, 2011, from both PGE-owned plants and from mid-Columbia projects, exceeded both normal levels and the nine months ended September 30, 2010 by 17% and 26%, respectively. Although total hydroelectric energy in the nine months ended September 30, 2010 was 10%

below normal, improved regional hydro conditions during the remainder of 2010 resulted in an 8% reduction from normal for the year. Energy from hydro resources is expected to exceed normal for 2011.

Actual NVPC was below baseline NVPC by approximately $36 million and $11 million for the nine months ended September 30, 2011 and 2010, respectively. As of September 30, 2011, PGE has recorded an estimated refund to customers of approximately $17 million pursuant to the PCAM, with no refund recorded as of September 30, 2010.

Gross margin was 59% in the nine months ended September 30, 2011, compared to 54% in the nine months ended September 30, 2010. The increase in Gross margin was driven by the 13% decrease in average variable power cost, the 4% increase in retail energy deliveries and the increase in retail customer prices resulting from the 2011 General Rate Case, which became effective January 1, 2011, and a tariff for the recovery of Boardman over a shortened operating life, which became effective July 1, 2011. Decreased wholesale sales partially offset the increase in gross margin in the nine months ended September 30, 2011.

Production and distribution expense increased $20 million, or 16%, in the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010. The increase was primarily due to an increase in operating and maintenance expenses at the Company's thermal generating plants (including extensive work performed during their planned annual outages) and at Biglow Canyon, the final phase of which was completed in August 2010. Also contributing to the increase were increases in delivery system expenses, reflecting higher labor costs and increased tree trimming activities, and certain legal settlement costs. Such increased expenses were partially offset by the insurance recovery of certain costs related to the Selective Water Withdrawal system on the Company's Pelton/Round Butte project on the Deschutes River.

Administrative and other expense increased $18 million, or 13%, in the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010. The increase was primarily due to increased incentive compensation, related to an improvement in projected corporate financial performance for 2011, higher pension costs, and an increase in the write-off of customer accounts receivable balances.

Depreciation and amortization expense decreased $3 million, or 2%, in the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010. A $13 million decrease related to the amortization of customer refunds of certain Oregon tax credits (offset in Revenues) was partially offset by increases in depreciation and amortization related to Biglow Canyon, Boardman, the smart meter project and certain intangible assets.

Taxes other than income taxes increased $7 million, or 10%, in the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010, primarily due to higher property taxes, resulting from both increased property values and tax rates, and higher city franchise fees related to increased Retail revenues.

Other income, net decreased $11 million, or 85%, in the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010, primarily due to a $9 million reduction in the allowance for equity funds used during construction, as a result of lower construction work in progress balances during the nine months ended September 30, 2011, related primarily to the August 2010 completion of Phase III of Biglow Canyon. Additionally, during the nine months ended September 30, 2011, a $2 million loss was recorded related to a decrease in the fair value of the non-qualified benefit plan trust assets, compared to a $2 million gain recorded in the comparable period of 2010.

Interest expense in the nine months ended September 30, 2011 was comparable to the nine months ended September 30, 2010, as a $6 million decrease in the allowance for funds used during construction, related primarily to the completion of Biglow Canyon, was offset by lower interest on long-term debt and certain regulatory liabilities.

Income taxes increased $2 million in the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010 primarily due to an increase in pre-tax income. The effective tax rates (approximately 26.3% and 28.8% in the nine months ended September 30, 2011 and 2010, respectively) are lower than the federal and state statutory rates primarily due to benefits from federal wind production tax credits, related to increased generation from Biglow Canyon, and state tax credits. The effective tax rate was lower in 2011 largely due to additional state tax expense in 2010 related to an Oregon rate change, requiring adjustment of the Company's deferred taxes and a smaller amount of wind production tax credits.

Liquidity and Capital Resources

Capital Requirements

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

	2011	2012	2013	2014	2015
Ongoing capital expenditures	$ 260	$ 260	$ 231	$ 232	$ 257
Boardman emissions controls (1)	19	11	12	—	—
Hydro licensing and construction	25	22	12	27	29
Total capital expenditures	$ 304 (2)	$ 293	$ 255	$ 259	$ 286
Long-term debt maturities	$ 10	$ 100	$ 100	$ 63	$ 70

(1) Represents 80% of estimated total costs based on installation of emissions controls to meet regulatory requirements. In 1985, PGE sold an undivided 15% interest in Boardman to a third party, reducing the Company's ownership interest from 80% to 65%. The purchaser has certain rights to participate in the financing of the portion of the total capital cost attributable to its interest. If the purchaser does not exercise its rights to finance the portion of the total cost attributable to its interest, PGE's share of the total cost for the emissions controls at Boardman is expected to be 80%.

(2) Amounts shown include preliminary engineering and removal costs, which are included in other net operating activities in the condensed consolidated statements of cash flows.

Ongoing capital expenditures — Capital spending requirements consist primarily of upgrades to and replacement of transmission, distribution, and generation infrastructure, as well as connections for new customers. Preliminary engineering costs, which consist of expenditures for preliminary surveys, plans, and investigations made for the purpose of determining the feasibility of utility projects, including certain projects discussed in the *Integrated Resource Plan* section below, are included in Ongoing capital expenditures. If PGE moves forward with the projects for which preliminary engineering costs are recorded, such costs are transferred to Construction work in progress, in Electric utility plant, net. If the projects are abandoned, such costs are expensed in the period such determination is made. If any preliminary engineering costs are expensed, the Company may seek regulatory recovery of such costs in customer prices, although there can be no guarantee such recovery would be granted. As of September 30, 2011 and December 31, 2010, preliminary engineering costs of $8 million and $13 million, respectively, are included in Other noncurrent assets in PGE's condensed consolidated balance sheets.

Boardman emissions controls — In December 2010, the Oregon Environmental Quality Commission adopted revised rules that establish new emissions limits at Boardman and provide for coal-fired operation to cease no later than December 31, 2020. The revised rules were approved by the EPA in June 2011.

The emissions limits imposed under the revised rules have required the addition of certain controls. The total cost of these controls, together with mercury controls required under a separate rulemaking process, is estimated at approximately $60 million (100% of total costs, excluding AFDC), the Company's portion of which is reflected in the table above. During the third quarter of 2011, mercury controls were installed and performance testing was completed. Certain required modifications are expected to be installed by the end of 2011. Dry Sorbent Injection testing is expected to occur during the fourth quarter 2011. The Company's portion of capital spending on the Boardman emissions controls to date is approximately $20 million.

In March 2011, the EPA issued proposed rules under the Clean Air Act's National Emission Standards that are intended to reduce emissions of Hazardous Air Pollutants (HAPs), which include heavy metals, acid gases, and other substances as defined in the proposal, from coal- and oil-fired electric utility steam generating units. These proposed rules reflect the application of maximum achievable control technology, or "MACT". Final rules are expected by the end of 2011.

The Company has not yet determined whether it can meet all the HAPs limits, as proposed, with current and planned control technologies. If the HAPs limits cannot be met with current and planned control technologies, the Company will need to evaluate the cost and benefit of additional emissions control technology to meet such limits, unless the proposed rules are modified or implemented with sufficient flexibility for generating units that have in place a federally enforceable shutdown plan.

Hydro licensing and construction — Capital spending requirements reflected in the table above relate primarily to modifications to the Company's hydro facilities to enhance fish passage and survival, as required by conditions contained in existing licenses.

Integrated Resource Plan — The Company's IRP, acknowledged by the OPUC in November 2010, included the following resource, capacity, and transmission projects:

- The addition of new generating plants and improvements to existing plants. The related RFP processes will determine the successful bidders for the new capacity, energy, and renewable resources described in the IRP and clarify the timing and total cost; and
- The construction of Cascade Crossing at an estimated total cost (in 2011 dollars) of $800 million to $1.0 billion. The Company continues to work with other stakeholders in planning the project and potential project partnerships.

Due to the uncertainty of these projects, the Capital Requirements table above does not include estimates for any amounts related to these projects beyond 2011. For further information on the Company's IRP and the projects subject to the RFP process, see Capital Requirements and Financing in the Overview section of this Item 2.

Liquidity

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

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

	Nine Months Ended September 30,	
	2011	**2010**
Cash and cash equivalents, beginning of period	$ 4	$ 31
Net cash provided by (used in):		
Operating activities	399	317
Investing activities	(214)	(364)
Financing activities	(92)	23
Increase in cash and cash equivalents	93	(24)
Cash and cash equivalents, end of period	$ 97	$ 7

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. The $82 million increase in cash provided by operating activities in the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010 was largely due to an increase in net income, after the consideration of noncash operating items, as well as a decrease in margin deposit requirements pursuant to power and natural gas purchase and sale agreements. Such increases were partially offset by a $45 million decrease in the income tax refunds received in 2011 compared to 2010 and a $14 million contribution to the voluntary employees’ beneficiary association trust (VEBA) in the third quarter of 2011. The VEBA funds the benefits of the Company’s non-contributory postretirement health and life insurance plans.

A significant portion of cash provided by operations consists of recovery in customer prices of non-cash charges for depreciation and amortization, which PGE estimates to be approximately $230 million in 2011.

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 $150 million decrease in net cash used in investing activities in the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010 was primarily due to lower capital expenditures resulting from the completion of Biglow Canyon Phase III in August 2010, as well as a $19 million distribution in 2010 from the Nuclear decommissioning trust to PGE.

The Company plans approximately $304 million of capital expenditures in 2011 related to upgrades and replacement of transmission, distribution and generation infrastructure. See 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, 2011, cash used in such activities consisted of the payment of dividends of $59 million, the repayment of commercial paper of $19 million, the repayment of long-term debt of $10 million, and capital distributions to noncontrolling interests of $4 million. During the nine months ended September 30, 2010, net cash provided by financing activities consisted primarily of proceeds received from the issuance of long-term debt of $249 million and the issuances of short-term debt and commercial paper of $20 million, partially offset by the repayment of long-term debt of $186 million and the payment of dividends of $58 million.

As of September 30, 2011, PGE does not expect to issue any long-term debt securities in 2011.

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 2011 consist of the following:

Declaration Date	Record Date	Payment Date	Dividends Declared Per Common Share
February 16, 2011	March 25, 2011	April 15, 2011	$ 0.260
May 11, 2011	June 24, 2011	July 15, 2011	0.265
August 3, 2011	September 26, 2011	October 17, 2011	0.265
October 26, 2011	December 27, 2011	January 17, 2012	0.265

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 financial condition and credit ratings, as well as on credit markets, both generally and for electric utilities in particular. Management believes that the availability of the 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.

Short-term Debt. PGE has approval from the FERC to issue short-term debt up to a total of $750 million through February 6, 2012 and has applied for a two year extension of the authorization in the amount of $700 million, which more closely aligns with the Company's projected liquidity needs. The Company currently has the following unsecured revolving credit facilities:

- A $370 million syndicated credit facility, with $10 million and $360 million scheduled to terminate July 2012 and July 2013, respectively;
- A $200 million syndicated credit facility, which is scheduled to terminate in December 2012; and
- A $30 million credit facility, which is scheduled to terminate in June 2013.

These credit facilities supplement operating cash flow and provide a primary source of liquidity. Pursuant to the individual terms of the agreements, the credit facilities may be used for general corporate purposes and as backup for commercial paper borrowings. The $370 million and $30 million credit facilities also permit the issuance of standby letters of credit. As of September 30, 2011, PGE had $89 million of letters of credit outstanding under the credit facilities and no commercial paper or borrowings outstanding. As of September 30, 2011, the aggregate unused credit available under the credit facilities was $511 million.

Long-term Debt. To fund current capital expenditures and maturities of long-term debt, PGE generally relies on the issuance of long-term debt. For 2011, PGE expects that cash provided by operating activities will fund total capital expenditures, which are expected to approximate $304 million. Accordingly, the Company does not anticipate issuing any long-term debt in 2011. During January 2011, PGE elected to have $10 million of Port of St. Helens Pollution Control Revenue Bonds redeemed and retired. PGE has no other long-term debt that is scheduled to mature in 2011.

Capital Structure. PGE's financial objectives include the balancing of debt and equity to maintain an optimal 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 acceptable credit ratings and allow access to long-term capital at optimal interest rates. PGE's common equity ratios were 47.9% and 46.7% as of September 30, 2011 and December 31, 2010, 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	A3	A-
Senior unsecured debt	Baa2	BBB
Commercial paper	Prime-2	A-2
Outlook	Stable	Stable

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 should Moody's and/or S&P reduce their credit rating on PGE's unsecured debt to below investment grade. 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 in PGE's condensed consolidated balance sheet, while any letters of credit issued are not reflected in the Company's condensed consolidated balance sheet.

As of September 30, 2011, PGE had posted approximately $151 million of collateral with these counterparties, consisting of $83 million in cash and $68 million in letters of credit, $20 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, 2011, the approximate amount of additional collateral that could be requested upon a single agency downgrade to below investment grade is approximately $130 million and decreases to approximately $95 million by December 31, 2011. The amount of additional collateral that could be requested upon a dual agency downgrade to below investment grade is approximately $312 million at September 30, 2011 and decreases to approximately $236 million by December 31, 2011.

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.

The issuance of additional First Mortgage Bonds requires that PGE meet certain provisions set forth in the Indenture of Mortgage and Deed of Trust (the Indenture) securing the bonds. PGE estimated that on September 30, 2011, under the most restrictive issuance test in the Indenture, the Company could have issued up to approximately $497 million of additional First Mortgage Bonds. Amounts could be further limited by regulatory authorizations or by covenants and tests contained in other financing agreements. PGE has the ability under certain circumstances to release property from the lien of the Indenture on the basis of property additions, bond retirements, and/or deposits of cash.

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, 2011, the Company's debt ratio, as calculated under the credit agreements, was 52.1%.

Off-Balance Sheet Arrangements

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

Contractual Obligations

PGE's contractual obligations for 2011 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, 2010, filed with the SEC on February 25, 2011. Such obligations have not changed materially as of September 30, 2011, except that the Company elected to make a $26 million contribution to its pension plan during the second quarter of 2011. PGE estimates future contributions to the Company's pension plan as follows: none in 2012; $35 million in 2013; and $43 million in each of 2014 and 2015. Such amounts are based on the most recent estimate of future discount rates and are the estimated minimum contributions required to meet the minimum funding requirements for pension plans under the Pension Protection Act of 2006.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

The Company is subject to various market risks which include commodity price risk, credit risk, foreign currency exchange rate risk, and interest rate 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, 2010, filed with the SEC on February 25, 2011.

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, 2011, these disclosure controls and procedures were effective.

Changes in Internal Control over Financial Reporting

During the quarter ended September 30, 2011, there were no changes in the Company'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, its internal control over financial reporting.

PART II - OTHER INFORMATION

Item 1. Legal Proceedings.

Sierra Club et al. v. Portland General Electric Company, U.S. District Court for the District of Oregon, Case No. CV 08-1136-HA.

In July 2011, the parties reached a preliminary settlement and filed a consent decree with the Court that resolved all of the plaintiffs' claims. On September 13, 2011, following a 45-day review period by the EPA and the U.S. Department of Justice, the Court approved the consent decree. Further information on this proceeding, including a description of the consent decree, is also contained in Part II, Item 1 of the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2011, filed with the SEC on August 5, 2011.

For information regarding the above proceeding and PGE's other 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, 2010, filed with the SEC on February 25, 2011.

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, 2010, filed with the SEC on February 25, 2011.

Item 6. Exhibits.

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.

* In accordance with Regulation S-T, the XBRL-related information in Exhibit 101 to this Quarterly Report on Form 10-Q shall be deemed "furnished" and not "filed."

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: November 2, 2011

By: /s/ Maria M. Pope
Maria M. Pope
Senior Vice President, 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:	November 2, 2011	By:	/s/ James J. Piro
			James J. Piro
			President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Maria M. Pope, 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:	November 2, 2011	By:	/s/ Maria M. Pope
			Maria M. Pope
			Senior Vice President, 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 Maria M. Pope, Senior Vice President, 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, 2011, as filed with the Securities and Exchange Commission on November 3, 2011 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/ Maria M. Pope
James J. Piro	Maria M. Pope
President and *Chief Executive Officer*	*Senior Vice President, Finance,* *Chief Financial Officer, and Treasurer*
Date: November 2, 2011	Date: November 2, 2011