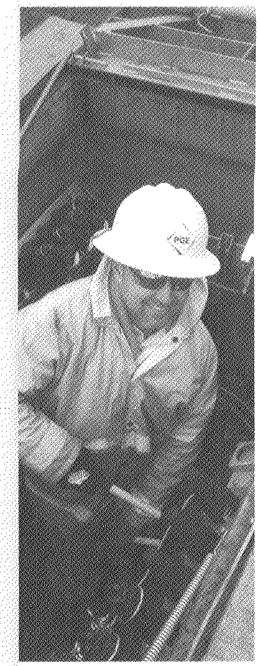
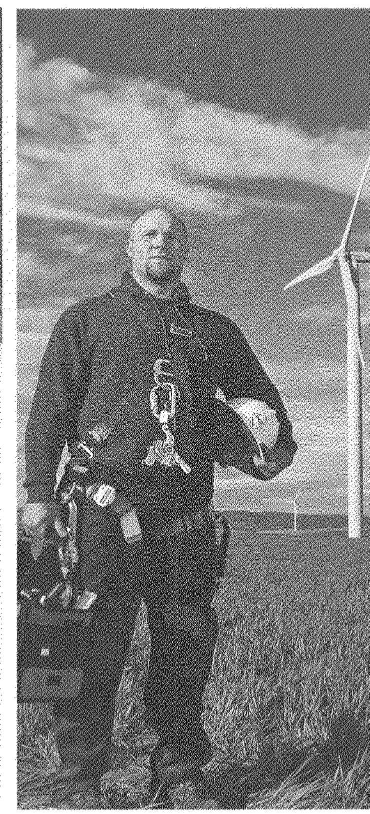
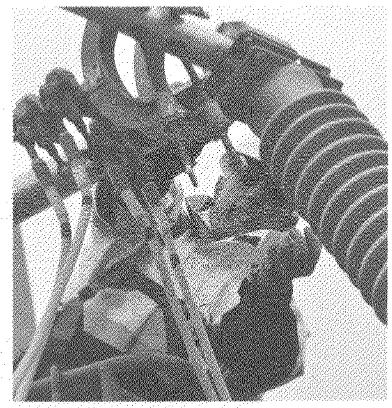
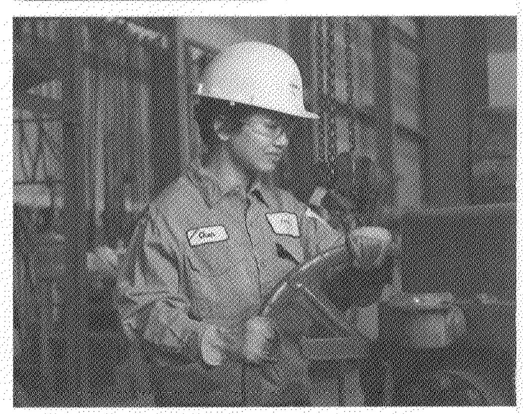


Portland General Electric Company

2012 Annual Report



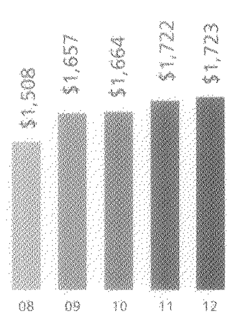




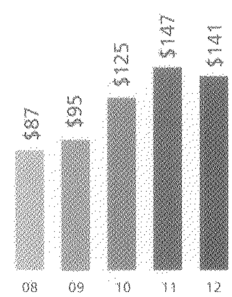
Portland General Electric

Financial Highlights

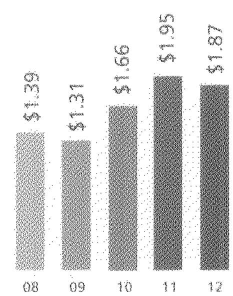
(Dollars in millions, except per share amounts)	2012	2011	2010
Operating revenues	$ 1,805	$ 1,813	$ 1,783
Net operating income	$ 302	$ 309	$ 267
Net income for common stock	$ 141	$ 147	$ 125
Return on average quarter-end equity	8.2%	9.0%	8.0%
Total assets	$ 5,670	$ 5,733	$ 5,491
Dividends declared per common share	$ 1.075	$ 1.055	$ 1.035
Weighted-average shares outstanding (in thousands), diluted	75,647	75,350	75,291
Customers	828,354	822,466	820,676
Long-term debt, including current portion	$ 1,636	$ 1,735	$ 1,808
Long-term debt/capitalization	48.4%	50.6%	52.8%
Senior secured debt ratings (S&P/Moody's)	A–/A3	A–/A3	A–/A3
Commercial paper ratings (S&P/Moody's)	A-2/P-2	A-2/P-2	A-2/P-2
Employees	2,603	2,634	2,671



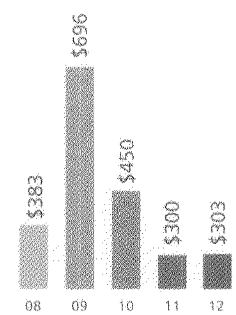
Total retail revenue



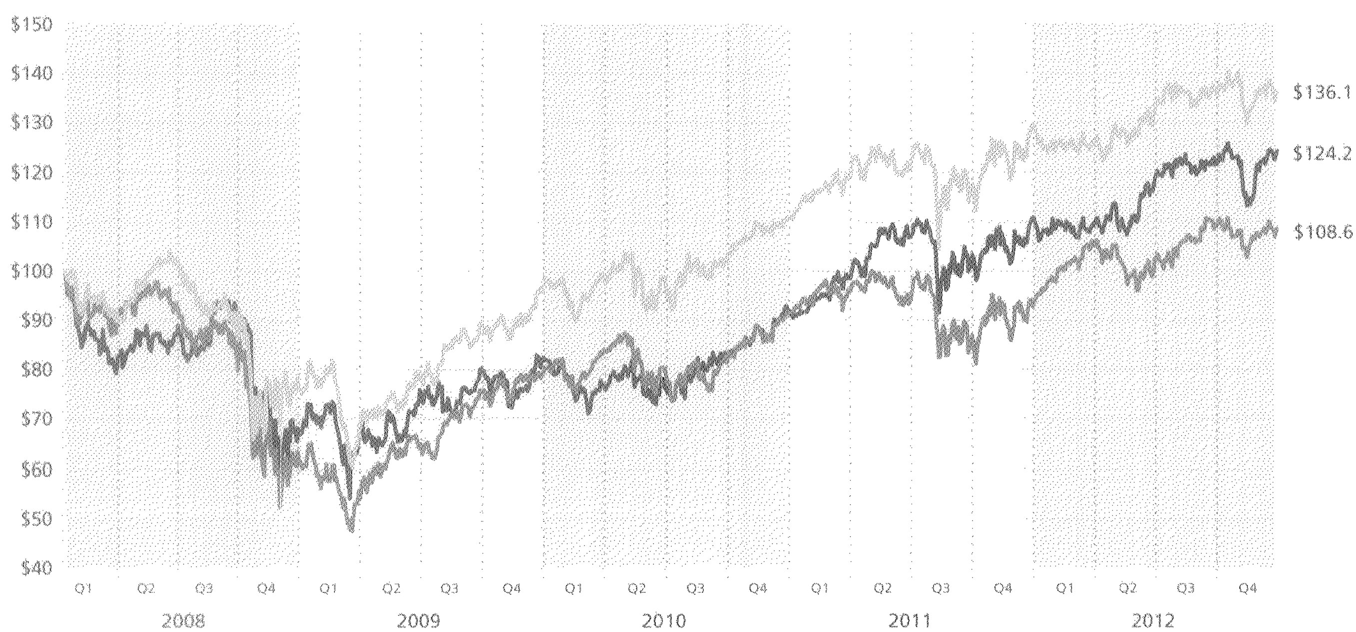
Net income



Earnings per share (diluted)



Capital expenditures



Stock Performance Graph[1]

1. *Assumes a $100 investment in Portland General Electric's common stock and each index on December 31, 2007, and that all dividends were reinvested.*

About Portland General Electric

Portland General Electric Company, headquartered in Portland, Oregon, is a fully integrated electric utility serving approximately 828,000 residential, commercial and industrial customers in Oregon. PGE common stock is traded on the New York Stock Exchange under the ticker symbol POR.

To Our Shareholders

Portland General Electric is executing our strategic plan to deliver a sustainable, affordable energy future. In 2012, we set in place the building blocks for growth by concentrating on operational excellence, business investments and corporate responsibility. This helped us achieve solid financial and operating results that delivered value to our customers and shareholders.

Operational Excellence

PGE's operating performance was excellent in 2012: Our distribution reliability metrics remain strong, and the availability of our generating facilities exceeded our goals for the year. Of course, one key indicator of performance is how our customers perceive the service we provide, and I'm pleased PGE continued to receive high marks from all of our customer classes, including ranking second nationally for large key customer satisfaction in the TQS Research, Inc. 2012 survey.

Our strong operations and continued focus on improved processes and efficiency helped PGE deliver net income of $141 million, or $1.87 per diluted share, for an 8.2 percent return on equity. Weather-adjusted retail energy deliveries were up 0.6 percent from 2011 with strong growth in the industrial sector, particularly in the second half of the year; however, actual sales were down due to warmer winter weather. With recent announcements of significant business expansion plans in our service area, as well as the uptick we've seen in housing and construction, we anticipate continued customer and load growth in 2013.

Capital expenditures in 2012 were $310 million, including investments in our transmission and distribution system to add capacity and boost reliability and power quality so we can effectively meet our customers' needs. PGE has maintained strong credit quality to finance our ongoing investments. At year-end, our equity-to-total capital ratio was 51 percent, and our investment-grade credit ratings for secured debt were A– and A3, by Standard & Poor's and Moody's, respectively, which keeps our financing costs low for customers.

Business Growth

We made significant progress implementing our 2009 Integrated Resource Plan action plan. In 2012, PGE issued requests for proposals for energy, flexible and seasonal peaking capacity, and renewable resources, and we are nearing the completion of these processes. PGE's Port Westward Unit 2 natural gas plant was selected as the flexible capacity resource in January 2013. The 220-megawatt plant is expected to cost $300 to $310 million, with construction beginning in April. The plant is expected to be in service in the first quarter of 2015. Negotiations are currently under way with the top-performing bids for the other three types of resources, which include power-purchase agreements and PGE-ownership options. We expect to announce the outcomes by midyear.

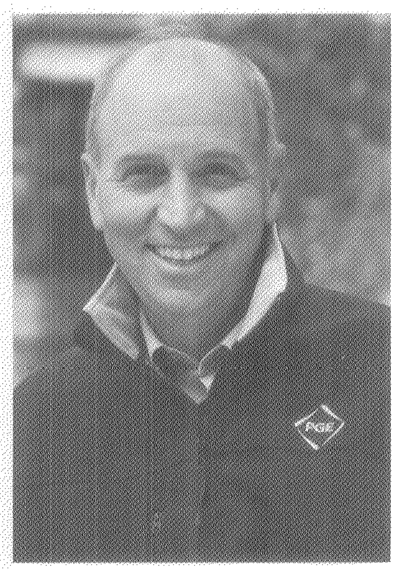
In January 2013, we signed a memorandum of understanding with Bonneville Power Administration to pursue a phased-in, integrated approach to our proposed Cascade Crossing Transmission Project. The project, as currently planned, would include a new transmission line, running approximately 120 miles from Boardman to central

Oregon, with PGE building at least two substations, installing series capacitors to boost capacity of existing lines, making other transmission investments in the Portland and Salem area, and exploring the possibility of asset exchanges and other potential transmission opportunities to deliver up to 2,600 megawatts to customers. While the cost of the revised project's full scope is subject to the outcome of negotiations with BPA, we expect it will be more than $800 million. Construction on the transmission line would take at least two years and could start as early as 2017.

As we plan for Oregon's energy future, we will need to make additional investments to meet our customers' needs and comply with regulatory requirements. We have been able to hold the line on costs for three years by implementing new technology and improving our processes; however, growing regulatory and inflationary costs, as well as other drivers, led us to file a general rate case based on a 2014 test year to request an overall price increase of 6.2 percent. We expect the new prices resulting from the thorough 10-month regulatory process to become effective on January 1, 2014.

Corporate Responsibility

At PGE, we recognize our success is integrally tied to the health of the communities we serve. As a result, we continue to be actively engaged in economic development throughout our service area, helping to recruit new industries, like semiconductor manufacturing and data centers, and working closely with existing companies to expand. I also want to recognize our employees' generosity to the communities we serve. In 2012, they volunteered more than 50,000 hours of their time and contributed more than $1 million to nonprofit organizations that work to help ensure our communities thrive.



PGE's talented employees are the key to our achievements, and I am proud of their hard work and dedication to our success. I am confident we will continue to work together to provide safe, reliable, sustainable and reasonably priced electricity with excellent service to our customers and a solid, stable investment for our shareholders.

Sincerely,

Jim Piro

Jim Piro
President and Chief Executive Officer
March 15, 2013

Form 10-K

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

FORM 10-K

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

For the fiscal year ended December 31, 2012

OR

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

For the Transition period from ______ to ______

Commission File Number 001-05532-99

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 S.W. Salmon Street
Portland, Oregon 97204
(503) 464-8000
(Address of principal executive offices, including zip code, and Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Common Stock, no par value	**New York Stock Exchange**
(Title of class)	(Name of exchange on which registered)

Securities registered pursuant to Section 12(g) of the Act: None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes [x] No [ ]

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes [ ] No [x]

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. Yes [x] No [ ]

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [x]

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 definition 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 [ ] No [x]

As of June 29, 2012, the aggregate market value of voting common stock held by non-affiliates of the Registrant was $2,008,462,492. For purposes of this calculation, executive officers and directors are considered affiliates.

As of February 15, 2013, there were 75,557,037 shares of common stock outstanding.

Documents Incorporated by Reference

Part III, Items 10 - 14	Portions of Portland General Electric Company's definitive proxy statement to be filed pursuant to Regulation 14A for the Annual Meeting of Shareholders to be held on May 22, 2013.

PORTLAND GENERAL ELECTRIC COMPANY
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2012

TABLE OF CONTENTS

DEFINITIONS

The abbreviations or acronyms defined below are used throughout this Form 10-K:

Abbreviation or Acronym	Definition
AFDC	Allowance for funds used during construction
ARO	Asset retirement obligation
AUT	Annual Power Cost Update Tariff
Beaver	Beaver natural gas-fired generating plant
Biglow Canyon	Biglow Canyon Wind Farm
Boardman	Boardman coal-fired generating plant
BPA	Bonneville Power Administration
CAA	Clean Air Act
Colstrip	Colstrip Units 3 and 4 coal-fired generating plant
Coyote Springs	Coyote Springs Unit 1 natural gas-fired generating plant
Dth	Decatherm = 10 therms = 1,000 cubic feet of natural gas
DEQ	Oregon Department of Environmental Quality
EPA	United States Environmental Protection Agency
ESA	Endangered Species Act
ESS	Electricity Service Supplier
FERC	Federal Energy Regulatory Commission
IRP	Integrated Resource Plan
ISFSI	Independent Spent Fuel Storage Installation
kV	Kilovolt = one thousand volts of electricity
Moody's	Moody's Investors Service
MW	Megawatts
MWa	Average megawatts
MWh	Megawatt hours
NRC	Nuclear Regulatory Commission
NVPC	Net Variable Power Costs
OATT	Open Access Transmission Tariff
OPUC	Public Utility Commission of Oregon
PCAM	Power Cost Adjustment Mechanism
Port Westward	Port Westward natural gas-fired generating plant
RPS	Renewable Portfolio Standard
S&P	Standard & Poor's Ratings Services
SEC	United States Securities and Exchange Commission
Trojan	Trojan nuclear power plant
USDOE	United States Department of Energy
VIE	Variable interest entity

PART I

ITEM 1. BUSINESS.

General

Portland General Electric Company (PGE or the Company) was incorporated in 1930 and is a vertically integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the state of Oregon. The Company operates as a cost-based, regulated electric utility, with revenue requirements and customer prices determined based on the forecasted cost to serve retail customers, and a reasonable rate of return as determined by the Public Utility Commission of Oregon (OPUC). PGE's retail load requirement is met with both Company-owned generation and power purchased in the wholesale market. The Company also participates in the wholesale market by purchasing and selling electricity and natural gas in order to obtain reasonably-priced power for its retail customers. PGE is publicly-owned, with its common stock listed on the New York Stock Exchange, and 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 state-approved service area allocation of approximately 4,000 square miles is located entirely within Oregon and includes 52 incorporated cities, of which Portland and Salem are the largest. The Company estimates that at the end of 2012 its service area population was 1.7 million, comprising approximately 44% of the state's population. During 2012, the Company added 5,888 customers and as of December 31, 2012, served a total of 828,354 retail customers.

PGE had 2,603 employees as of December 31, 2012, with 809 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 775 and 34 employees and expire in February 2015 and August 2014, respectively.

Available Information

PGE's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available and may be accessed free of charge through the Investors section of the Company's Internet website at PortlandGeneral.com as soon as reasonably practicable after the reports are electronically filed with, or furnished to, the United States Securities and Exchange Commission (SEC). It is not intended that PGE's website and the information contained therein or connected thereto be incorporated into this Annual Report on Form 10-K. Information may also be obtained via the SEC Internet website at sec.gov.

Regulation and Rates

PGE is subject to both federal and state regulation, which can have a significant impact on the operations of the Company. In addition to those agencies and activities discussed below, the Company is subject to regulation by certain environmental agencies, as described in the Environmental Matters section in this Item 1.

Federal Regulation

PGE is subject to regulation by several federal agencies, including the Federal Energy Regulatory Commission (FERC), the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA), and the Nuclear Regulatory Commission (NRC).

FERC Regulation

The Company is a "licensee," a "public utility," and a "user, owner and operator of the bulk power system," as defined in the Federal Power Act, and is subject to regulation by the FERC in matters related to wholesale energy activities, transmission services, reliability and cyber security standards, natural gas pipelines, hydroelectric projects, accounting policies and practices, short-term debt issuances, and certain other matters.

Wholesale Energy—PGE has authority under its FERC Market-Based Rates tariff to charge market-based rates for wholesale energy sales. Re-authorization for continued use of such rates requires the filing of triennial market power studies with the FERC. The Company's next triennial market power study is due in June 2013.

Transmission—PGE offers transmission service pursuant to its Open Access Transmission Tariff (OATT), which is filed with the FERC. As required by the OATT, PGE provides information regarding its transmission business on its Open Access Same-time Information System, also known as OASIS. As of December 31, 2012, PGE owned approximately 1,100 circuit miles of transmission lines. For additional information, see the Transmission and Distribution section in this Item 1. and in Item 2.—"Properties."

Reliability and Cyber Security Standards—Pursuant to the Energy Policy Act of 2005, the FERC has adopted mandatory reliability standards for owners, users and operators of the bulk power system. Such standards, which are applicable to PGE, were developed by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC), which has responsibility for compliance and enforcement of these standards. These standards include Critical Infrastructure Protection standards, a set of cyber security standards that provide a framework to identify and protect critical cyber assets used to support reliable operation of the bulk power system.

Pipeline—The Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978 provide the FERC authority in matters related to the extension, enlargement, safety, and abandonment of jurisdictional pipeline facilities, as well as transportation rates and accounting for interstate natural gas commerce. PGE is subject to such authority as the Company has a 79.5% ownership interest in and is the operator of record of the Kelso-Beaver Pipeline, a 17-mile interstate pipeline that provides natural gas to the Company's Port Westward and Beaver plants. As the operator of record, PGE is subject to the requirements and regulations enacted under the Pipeline Safety Laws administered by the PHMSA, which include safety standards, operator qualification standards and public awareness requirements.

Hydroelectric Licensing—Under the Federal Power Act, PGE's hydroelectric generating plants are subject to FERC licensing requirements. These include an extensive public review process that involves the consideration of numerous natural resource issues and environmental conditions. PGE holds FERC licenses for the Company's projects on the Deschutes, Clackamas, and Willamette Rivers. For additional information, see the Environmental Matters section in this Item 1. and Generating Facilities section in Item 2.—"Properties."

Accounting Policies and Practices—Pursuant to applicable provisions of the Federal Power Act, PGE prepares financial statements in accordance with the accounting requirements of the FERC, as set forth in its applicable

Uniform System of Accounts and published accounting releases. Such financial statements are included in annual and quarterly reports filed with the FERC.

Short-term Debt—Pursuant to applicable provisions of the Federal Power Act and FERC regulations, regulated public utilities are required to obtain FERC approval to issue certain securities. The Company, pursuant to an order issued by the FERC on December 28, 2011, is authorized to issue up to $700 million of short-term debt through February 6, 2014.

NRC Regulation

The NRC regulates the licensing and decommissioning of nuclear power plants, including PGE's Trojan nuclear power plant (Trojan), which was closed in 1993. The NRC approved the 2003 transfer of spent nuclear fuel from a spent fuel pool to a separately licensed dry cask storage facility that will house the fuel on the plant site until a U.S. Department of Energy (USDOE) facility is available. Radiological decommissioning of the plant site was completed in 2004 under an NRC-approved plan, with the plant's operating license terminated in 2005. Spent fuel storage activities will continue to be subject to NRC regulation until all nuclear fuel is removed from the site and radiological decommissioning of the storage facility is completed. For additional information on spent nuclear fuel storage activities, see Note 7, Asset Retirement Obligations in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

State of Oregon Regulation

PGE is subject to the jurisdiction of the OPUC, which is comprised of three members appointed by Oregon's governor to serve non-concurrent four-year terms.

The OPUC reviews and approves the Company's retail prices (see "*Ratemaking*" below) and establishes conditions of utility service. In addition, the OPUC regulates the issuance of securities, prescribes accounting policies and practices, and reviews applications to sell utility assets and engage in transactions with affiliated companies, as well as applications of persons or entities seeking to acquire substantial influence over a public utility. The OPUC also reviews the Company's generation and transmission resource acquisition plans, pursuant to an integrated resource planning process.

Oregon's Energy Facility Siting Council (EFSC) has regulatory and siting responsibility for large electric generating facilities, high voltage transmission lines, gas pipelines, and radioactive waste disposal sites. The EFSC also has responsibility for overseeing the decommissioning of Trojan. The seven volunteer members of the EFSC are appointed to four-year terms by Oregon's governor, with staff support provided by the Oregon Department of Energy.

Integrated Resource Plan—Unless the OPUC directs otherwise, PGE is required to file with the OPUC an Integrated Resource Plan (IRP) within two years of its previous IRP acknowledgment order. Based on direction from the OPUC, PGE is required to file its next IRP in November 2013. The IRP guides the utility on how it will meet future customer demand and describes the Company's future energy supply strategy, reflecting new technologies, market conditions, and regulatory requirements. The primary goal of the IRP is to identify an acquisition plan for generation, transmission, demand-side and energy efficiency resources that, along with the Company's existing portfolio, provides the best combination of expected cost and associated risks and uncertainties for PGE and its customers. For additional information on PGE's most recent IRP, see "*Future Energy Resource Strategy*" in the Power Supply section in this Item 1.

Ratemaking—Under Oregon law, the OPUC is required to ensure that prices and terms of service are fair, non-discriminatory, and provide regulated companies an opportunity to earn a reasonable return on their investments. Customer prices are determined through formal ratemaking proceedings that generally include testimony by participating parties, discovery, public hearings, and the issuance of a final order. Participants in such proceedings, which are conducted under established procedural schedules, include PGE, OPUC staff, and intervenors representing PGE customer groups. The following are the more significant regulatory mechanisms and proceedings under which customer prices are determined:

- *General Rate Cases*. PGE periodically evaluates the need to change its retail electric price structure to sufficiently cover its operating costs and provide a reasonable rate of return. Such changes are requested pursuant to a comprehensive general rate case process that includes a forecasted test year, debt-to-equity capital structure, return on equity, and overall rate of return. Revenue requirements and retail customer price changes are proposed based upon such factors. PGE's most recent general rate case was the 2011 General Rate Case, which became effective on January 1, 2011. In February 2013, PGE filed a general rate case with a 2014 test year (2014 General Rate Case). For additional information, see the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."
- *Power Costs*. In addition to price changes resulting from the general rate case process, the OPUC has approved the following mechanisms by which PGE can adjust retail customer prices to cover the Company's Net Variable Power Costs (NVPC), which consist of the cost of purchased power and fuel used in generation (including related transportation costs) less revenues from wholesale power and fuel sales:
    - Annual Power Cost Update Tariff (AUT). Under this tariff, customer prices are adjusted annually to reflect the latest forecast of NVPC. Such forecasts assume average regional hydro conditions (based on seventy years of stream flow data covering the period 1928 - 1998) and current hydro operating parameters. The NVPC forecasts also assume average wind conditions (based on wind studies completed in connection with the permitting process of the wind farm) for PGE-owned wind generation and expected operating conditions for thermal generating plants. An initial NVPC forecast, submitted to the OPUC by April 1st each year, is updated during such year and finalized in November of the same year. Based upon the final forecast, new prices, as approved by the OPUC, become effective at the beginning of the next calendar year; and
    - Power Cost Adjustment Mechanism (PCAM). Customer prices can also be adjusted to reflect a portion of the difference between each year's forecasted NVPC included in prices (baseline NVPC) and actual NVPC for the year. Under the PCAM, PGE is subject to a portion of the business risk or benefit associated with the difference between actual NVPC and baseline NVPC. The PCAM utilizes an asymmetrical deadband range within which PGE absorbs cost variances, with a 90/10 sharing of such variances between customers and the Company outside of the deadband. The deadband range is fixed at $15 million below, to $30 million above, baseline NVPC. Annual results of the PCAM are subject to application of a regulated earnings test, under which a refund will occur only to the extent that it results in PGE's actual regulated return on equity (ROE) for that year being no less than 1% above the Company's latest authorized ROE. A collection will occur only to the extent that it results in PGE's actual regulated ROE for that year being no greater than 1% below the Company's authorized ROE. A final determination of any customer refund or collection is made by the OPUC through a public filing and review typically during the second half of the following year. For additional information, see the Results of Operations section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."
- *Renewable Energy*. The 2007 Oregon Renewable Energy Act (the Act) established a Renewable Portfolio Standard (RPS) which requires that PGE serve at least 5% of its retail load with renewable resources by 2011, 15% by 2015, 20% by 2020, and 25% by 2025. PGE met the 2011 requirement and expects to have sufficient resources to meet the 2015 requirements with additional resources included in its most recent IRP. The Act also allows Renewable Energy Credits, resulting from energy generated from qualified renewable resources placed in service after January 1, 1995 and certified low impact hydroelectric power resources, to be used to meet the Company's RPS compliance obligation. For additional information, see the Power Supply section in this Item 1.

  The Act also provides for the recovery in customer prices of all prudently incurred costs required to comply with the RPS. Under a renewable adjustment clause (RAC) mechanism, PGE can recover the revenue requirement of new renewable resources and associated transmission that are not yet included in prices. Under the RAC, PGE submits a filing by April 1st of each year for new renewable resources expected to be placed in service in the current year, with prices to become effective January 1st of the following year. In addition, the RAC provides for the deferral and subsequent recovery of eligible costs incurred prior to January 1st of the following year.

For additional information, see the "Legal, Regulatory and Environmental Matters" discussion in the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Other ratemaking proceedings can involve charges or credits related to specific costs, programs, or activities, as well as the recovery or refund of deferred amounts recorded pursuant to specific OPUC authorization. Such amounts are generally collected from, or refunded to, retail customers through the use of supplemental tariffs.

Retail Customer Choice Program—PGE's commercial and industrial customers have access to pricing options other than cost-of-service, including direct access and daily market index based pricing. All commercial and industrial customers are eligible for direct access, whereby customers purchase their electricity from an Electricity Service Supplier (ESS), and PGE continues to deliver the energy to the customers. Large commercial and industrial customers may elect to be served by PGE on a daily market index based price. Certain large commercial and industrial customers may elect to be removed from cost-of-service pricing for a fixed three-year or a minimum five-year term, to be served either by an ESS or PGE under a daily market index based price. Participation in the fixed three-year and minimum five-year opt-out programs is capped at 300 average megawatts (MWa).

The majority of the energy supplied under PGE's Retail Customer Choice program is provided to customers that have elected service from an ESS under the minimum five-year opt-out program. In 2012, ESSs supplied direct access customers with a total retail load representing 6% of the Company's total retail energy deliveries for the year. The maximum retail load allowed to be supplied under the fixed three-year and minimum five-year opt-out programs would represent approximately 14% of the Company's total retail energy deliveries for 2012.

The retail customer choice program has no material impact on the Company's financial condition or operating results. Revenue changes resulting from increases or decreases in electricity sales to direct access customers are substantially offset by changes in the Company's cost of purchased power and fuel. Further, the program provides for "transition adjustment" charges or credits to direct access and market based pricing customers that reflect the above- or below-market cost of energy resources owned or purchased by the Company. Such adjustments are designed to ensure that the costs or benefits of the program do not unfairly shift to those customers that continue to purchase their energy requirements from the Company.

In addition to cost-of-service pricing, residential and small commercial customers can select portfolio options from PGE that include time-of-use and renewable resource pricing.

Energy Efficiency Funding—Oregon law provides for a "public purpose charge" to fund cost-effective energy efficiency measures, new renewable energy resources, and weatherization measures for low-income housing. This charge, equal to 3% of retail revenues, is collected from customers and remitted to the Energy Trust of Oregon (ETO) and other agencies for administration of these programs. Approximately $50 million and $51 million was collected from customers for this charge in 2012 and 2011, respectively.

In addition to the public purpose charge, PGE also remits to the ETO amounts collected under an Energy Efficiency Adjustment tariff to fund additional energy efficiency measures. This charge was approximately 2.7% and 1.8% of retail revenues for applicable customers in 2012 and 2011, respectively. Under the tariff, approximately $41 million and $28 million was collected from eligible customers in 2012 and 2011, respectively.

Decoupling—The decoupling mechanism, authorized through 2013, is intended to provide for recovery of margin lost as a result of a reduction in electricity sales attributable to energy efficiency and conservation efforts by residential and certain commercial customers. The mechanism provides for collections from customers if weather adjusted use per customer is lower than levels included in the Company's most recent general rate case; it also provides for customer refunds if weather adjusted use per customer exceeds levels included in the most recent general rate case.

During 2012, PGE recorded an estimated refund of $1 million, which resulted from weather adjusted use per customer being slightly higher than levels projected in the 2011 General Rate Case. Pending review and approval by the OPUC, any resulting refund to customers would be expected over a one-year period beginning June 1, 2013. For 2011, the Company recorded an estimated refund of $2 million, as weather adjusted use per customer was slightly higher than levels included in the 2011 General Rate Case. After review, the OPUC approved refunds to customers over a one-year period that began June 1, 2012.

Regulatory Accounting

PGE is subject to accounting principles generally accepted in the United States of America (GAAP), and as a regulated public utility, the effects of rate regulation are reflected in its financial statements. These principles provide for the deferral as regulatory assets of certain actual or estimated costs that would otherwise be charged to expense, based on expected recovery from customers in future prices. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on expected future credits or refunds to customers. PGE records regulatory assets or liabilities if it is probable that they will be reflected in future prices, based on regulatory orders or other available evidence.

The Company periodically assesses the applicability of regulatory accounting to its business, considering both the current and anticipated future rate environment and related accounting guidance. For additional information, see "*Regulatory Assets and Liabilities*" in Note 2, Summary of Significant Accounting Policies, and Note 6, Regulatory Assets and Liabilities, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Customers and Revenues

PGE generates revenue through the sale and delivery of electricity to retail customers. The Company conducts retail electric operations exclusively in Oregon within a service area approved by the OPUC. Within its service territory, the Company competes with: i) the local natural gas distribution company for the energy needs of residential and commercial space heating, water heating, and appliances; and ii) fuel oil suppliers, primarily for residential customers' space heating needs. In addition, the Company distributes power to commercial and industrial customers that choose to purchase their energy supply from an ESS. The Company includes such "direct access" customers in its customer counts and energy delivered to such customers in its total retail energy deliveries, as reflected in the tables below. Retail revenues include only delivery charges and transition adjustments for these customers.

Retail Revenues

Retail customers are classified as residential, commercial, or industrial, with no single customer representing more than 4% of PGE's total retail revenues or 5% of total retail deliveries. While the 20 largest commercial and industrial customers constituted 11% of total retail revenues in 2012, they represented nine different groups including high technology, paper manufacturing, metal fabrication, health services, and governmental agencies.

PGE's Retail revenues (dollars in millions), retail energy deliveries (MWh in thousands), and average number of retail customers consist of the following for the years presented:

	Years Ended December 31,					
	2012		2011		2010	
Retail revenues[1] (dollars in millions):						
Residential	$ 860	50%	$ 877	51%	$ 803	48%
Commercial	633	37	635	37	601	36
Industrial	226	13	226	13	221	14
Subtotal	1,719	100	1,738	101	1,625	98
Other accrued (deferred) revenues, net	4	—	(16)	(1)	39	2
Total retail revenues	$ 1,723	100%	$ 1,722	100%	$ 1,664	100%
Retail energy deliveries[2] (MWh in thousands):						
Residential	7,505	39%	7,733	40%	7,452	40%
Commercial	7,402	39	7,419	38	7,277	39
Industrial	4,283	22	4,193	22	4,004	21
Total retail energy deliveries	19,190	100%	19,345	100%	18,733	100%
Average number of retail customers:						
Residential	723,440	87%	719,977	87%	717,719	88%
Commercial	103,766	13	102,940	13	102,282	12
Industrial	261	—	255	—	265	—
Total	827,467	100%	823,172	100%	820,266	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.

Additional averages for retail customers are as follows:

	Years Ended December 31,		
	2012	2011	2010
Usage per customer (in kilowatt hours):			
Residential	10,375	10,740	10,384
Commercial	71,343	72,075	71,148
Industrial	16,409,211	16,572,913	15,051,038
Revenue per customer (in dollars):			
Residential	$ 1,113	$ 1,160	$ 1,049
Commercial	6,041	6,194	5,825
Industrial	863,402	900,805	828,536
Revenue per kilowatt hour (in cents):			
Residential	10.72¢	10.80¢	10.10¢
Commercial	8.47	8.59	8.19
Industrial	5.26	5.44	5.50

For additional information, see the Results of Operations section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

In accordance with state regulations, PGE's retail customer prices are determined through general rate case proceedings and various tariffs filed with the OPUC from time to time, and are based on the Company's cost of service. Additionally, the Company offers different pricing options that include a daily market price option, renewable energy options, which are offered to residential and small commercial customers, and time-of-use options. For additional information on customer options, see "*Retail Customer Choice Program*" within the Regulation and Rates section of this Item 1. Additional information on the customer classes follows.

Residential customers include single family housing, multiple family housing (such as apartments, duplexes, and town homes), mobile homes, and small farms. Residential demand is sensitive to the effects of weather, with demand historically highest during the winter heating season. Due to the increased use of air conditioning in PGE's service territory, the summer peaks have increased in recent years. Economic conditions can also affect demand from the Company's residential customers, as historical data suggests that high unemployment rates contribute to a decrease in demand. Residential demand is also impacted by energy efficiency measures; however, the Company's decoupling mechanism is intended to mitigate the financial effects of such measures.

While the number of residential customers increased during 2012, total residential deliveries decreased 2.9% compared to 2011 driven by warmer weather conditions during the heating season in 2012. During 2011, as a result of cooler weather during the heating season and an increase in the average number of customers, total residential deliveries increased 3.8% compared to 2010.

Commercial customers consist of non-residential customers who accept energy deliveries at voltages equivalent to those delivered to residential customers. This customer class consists of most businesses, including small industrial companies, and public street and highway lighting accounts.

Demand from the Company's commercial customers is somewhat less susceptible to weather conditions than the residential class, although weather does have an effect on commercial demand. Economic conditions and fluctuations in total employment in the region can also lead to corresponding changes in energy demand from commercial customers. Commercial demand is also impacted by energy efficiency measures, the financial effects of which are partially mitigated by the Company's decoupling mechanism.

In 2012, the unfavorable weather effects compared with 2011 nearly offset the addition of an average of over 800 new customers, contributing to the 0.2% decrease in deliveries to commercial customers compared with 2011, while Oregon non-farm employment increased 1.2%. In 2011, the favorable weather effects combined with the addition of an average of nearly 700 new customers contributed to the 2.0% increase in deliveries to commercial customers compared with 2010, as Oregon non-farm employment increased 1.6%.

Industrial customers consist of non-residential customers who accept delivery at higher voltages than commercial customers, with pricing based on the amount of electricity delivered and the applicable tariff. Demand from industrial customers is primarily driven by economic conditions, with weather having little impact on this customer class.

A change in economic activity can lead to a change in energy demand from the Company's industrial customers. In 2012, the Company's industrial energy deliveries increased 2.1% compared to 2011, driven primarily by expansion in the high tech sector. In 2011, industrial deliveries rose 4.7% compared to 2010 as demand increased from certain paper production customers, and the general economic conditions improved.

Other accrued revenues, net include items that are not currently in customer prices, but are expected to be in prices in a future period. Such amounts include deferrals recorded under the RAC, the PCAM, and the decoupling mechanism. For further information on these items, see "*State of Oregon Regulation*" in the Regulation and Rates section of this Item 1.

Wholesale Revenues

PGE participates in the wholesale electricity marketplace in order to balance its supply of power to meet the needs of its retail customers. Interconnected transmission systems in the western United States serve utilities with diverse load requirements and allow the Company to purchase and sell electricity within the region depending upon the relative price and availability of power, hydro conditions, and daily and seasonal retail demand. Wholesale revenues represented 3% of total revenues in each of 2012 and 2011.

The majority of PGE's wholesale electricity sales is to utilities and power marketers and is predominantly short-term. The Company may net purchases and sales with the same counterparty rather than simultaneously receiving and delivering physical power, with only the net amount of those purchases or sales required to meet retail and wholesale obligations physically settled.

Other Operating Revenues

Other operating revenues consist primarily of gains and losses on the sale of excess natural gas, as well as revenues from transmission services, excess transmission capacity resales, excess fuel oil sales, pole contact rentals, and other electric services provided to customers. Other operating revenues represented 2% of total revenues in each of 2012 and 2011.

Seasonality

Demand for electricity by PGE's residential and, to a lesser extent, commercial customers is affected by seasonal weather conditions, as discussed above. The Company uses heating and cooling degree-days to determine the effect of weather on the demand for electricity. Heating and cooling degree-days provide cumulative variances in the average daily temperature from a baseline of 65 degrees, over a period of time, to indicate the extent to which customers are likely to use, or have used, electricity for heating or air conditioning. The higher the number of degree-days, the greater the expected demand for heating or cooling.

The following table indicates the heating and cooling degree-days for the most recent three-year period, along with 15-year averages for the most recent year provided by the National Weather Service, as measured at Portland International Airport:

	Heating Degree-Days	Cooling Degree-Days
2012	4,169	436
2011	4,650	362
2010	4,187	314
15-year average for 2012	4,235	456

PGE's all-time high net system load peak of 4,073 Megawatts (MW) occurred in December 1998. The Company's all-time "summer peak" of 3,949 MW occurred in July 2009. The following tables present the Company's average winter and summer loads for the periods indicated along with the corresponding peak load and month in which it occurred:

Winter Loads (MW)

	Average	Peak	Month
2012	2,529	3,426	January
2011	2,612	3,555	January
2010	2,445	3,582	November

Summer Loads (MW)

	Average	Peak	Month
2012	2,249	3,597	August
2011	2,233	3,340	September
2010	2,220	3,544	August

The Company tracks and evaluates both load growth and peak load requirements for purposes of long-term load forecasting and integrated resource planning as well as for preparing general rate case assumptions. Behavior patterns, conservation, energy efficiency initiatives and measures, weather effects, economic conditions, and demographic changes all play a role in determining expected future customer demand and the resulting resources the Company will need to adequately meet those loads and maintain adequate capacity reserves.

Power Supply

PGE relies upon its generating resources as well as short- and long-term power and fuel purchase contracts to meet its customers' energy requirements. The Company executes economic dispatch decisions concerning its own generation, and participates in the wholesale market as a result of those economic dispatch decisions, in an effort to obtain reasonably-priced power for its retail customers, manage risk, and administer its current long-term wholesale contracts. The Company also promotes energy efficiency measures to meet its energy requirements.

PGE's generating resources consist of five thermal plants (natural gas- and coal-fired turbines), seven hydroelectric plants, and a wind farm located at Biglow Canyon in eastern Oregon. The volume of electricity the Company generates is dependent upon, among other factors, the capacity and availability of its generating resources. Capacity of the thermal plants represents the MW the plant is capable of generating under normal operating conditions, net of electricity used in the operation of the plant. The capacity of the Company's thermal generating resources is also affected by ambient temperatures. Capacity of both hydro and wind generating resources represent the nameplate MW, which varies from actual energy expected to be received as these types of generating resources are highly dependent upon river flows and wind conditions, respectively. Availability represents the percentage of the year the plant was available for operations, which reflects the impact of planned and forced outages. For a complete listing of these facilities, see "*Generating Facilities*" in Item 2.—"Properties."

PGE's resource capacity (in MW) was as follows:

	As of December 31,					
	2012		2011		2010	
	Capacity	%	Capacity	%	Capacity	%
Generation:						
Thermal:						
Natural gas	1,172	28%	1,172	28%	1,157	24%
Coal	670	16	670	16	670	14
Total thermal	1,842	44	1,842	44	1,827	38
Hydro (1)	489	12	489	12	489	10
Wind (2)	450	11	450	11	450	9
Total generation	2,781	67	2,781	67	2,766	57
Purchased power:						
Long-term contracts:						
Capacity/exchange	160	4	190	4	540	11
Hydro	588	14	579	14	743	15
Wind	39	1	38	1	38	1
Solar	13	—	6	—	—	—
Other	117	3	110	3	135	3
Total long-term contracts	917	22	923	22	1,456	30
Short-term contracts	475	11	458	11	612	13
Total purchased power	1,392	33	1,381	33	2,068	43
Total resource capacity	4,173	100%	4,162	100%	4,834	100%

(1) Capacity represents nameplate and differs from expected energy to be generated, which is expected to range from 195 MWa to 245 MWa, dependent upon river flows.

(2) Capacity represents nameplate and differs from expected energy to be generated, which is expected to range from 135 MWa to 180 MWa, dependent upon wind conditions.

For information regarding actual generating output and purchases for the years ended December 31, 2012, 2011 and 2010, see the Results of Operations section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Generation

The portion of PGE's retail load requirements generated by its plants varies from year to year and is determined by various factors, including planned and forced outages, availability and price of coal and natural gas, precipitation and snow-pack levels, the market price of electricity, and wind variability.

Thermal PGE has a 65% ownership interest in Boardman, which it operates, and a 20% ownership interest in Colstrip Units 3 and 4 (Colstrip), which is operated by a third party. These two coal-fired generating facilities provided approximately 19% of the Company's total retail load requirement in 2012, compared with 21% in 2011 and 26% in 2010. The Company's three natural gas-fired generating facilities, Port Westward, Beaver, and Coyote Springs, provided approximately 15% of its total retail load requirement in 2012, compared with 11% in 2011 and 24% in 2010.

The thermal plants provide reliable power for the Company's customers and capacity reserves. These resources have a combined capacity of 1,842 MW, representing approximately 66% of the net capacity of PGE's generating facilities. Thermal plant availability, excluding Colstrip, was 92% in 2012, compared with 90% in 2011 and 94% in 2010, while Colstrip plant availability was 93% in 2012, compared with 84% in 2011 and 95% in 2010.

Hydro The Company's FERC-licensed hydroelectric projects consist of Pelton/Round Butte on the Deschutes River near Madras, Oregon (discussed below), four plants on the Clackamas River, and one on the Willamette River. The licenses for these projects expire at various dates ranging from 2035 to 2055. Although these plants have a combined capacity of 489 MW, actual energy received is dependent upon river flows. Energy from these resources provided 10% of the Company's total retail load requirement in 2012, 2011, and 2010, with availability of 99% in 2012, compared with 100% in 2011 and 99% in 2010. Northwest hydro conditions have a significant impact on the region's power supply, with water conditions significantly impacting PGE's cost of power and its ability to economically displace more expensive thermal generation and spot market power purchases.

PGE has a 66.67% ownership interest in the 450 MW Pelton/Round Butte hydroelectric project on the Deschutes River, with the remaining interest held by the Confederated Tribes of the Warm Springs Reservation of Oregon (Tribes). A 50-year joint license for the project, which is operated by PGE, was issued by the FERC in 2005. The Tribes have an option to purchase an additional undivided 16.66% interest in Pelton/Round Butte at its discretion on or after December 31, 2021. The Tribes have a second option to purchase an undivided 0.02% interest in Pelton/Round Butte at its discretion on or after April 1, 2041. If both options are exercised by the Tribes, the Tribes' ownership percentage would exceed 50%.

Wind Biglow Canyon Wind Farm (Biglow Canyon), located in Sherman County, Oregon, is PGE's largest renewable energy resource with 217 wind turbines with a total nameplate capacity of approximately 450 MW. It was completed and placed in service in three phases between December 2007 and August 2010. The energy from Biglow Canyon provided 6% of the Company's total retail load requirement in both 2012 and 2011, and 4% in 2010. Availability for Biglow Canyon was 98% in 2012, compared with 97% in 2011 and 96% in 2010. The expected energy from wind resources differs from the nameplate capacity and is expected to range from 135 MWa to 180 MWa for Biglow Canyon, dependent upon wind conditions.

Dispatchable Standby Generation (DSG)—PGE has a DSG program under which the Company can start, operate, and monitor customer-owned standby generators when needed to meet peak demand. The program helps provide operating reserves for the Company's generating resources and, when operating, can supply most or all of DSG customer loads. As of December 31, 2012, there were 40 projects that together can provide approximately 87 MW of diesel-fired capacity at peak times. In addition, there were 10 projects under construction that are expected to provide an additional 18 MW.

Fuel Supply—PGE contracts for natural gas and coal supplies required to fuel the Company's thermal generating plants, with certain plants also able to operate on fuel oil if needed. In addition, the Company uses forward, swap, and option contracts to manage its exposure to volatility in natural gas prices.

Coal

Boardman—PGE has fixed-price purchase agreements that provide coal for Boardman into 2014. The coal is obtained from surface mining operations in Wyoming and Montana and is delivered by rail under two separate ten-year transportation contracts which extend through 2013.

PGE expects to begin seeking requests for proposal in 2013 for the purchase of coal to fill open positions for 2014 and beyond. The terms of any contracts and quality of coal are expected to be staged in alignment with the timing of the installation of required emissions controls. For additional information on Boardman's emissions controls, see "*Capital Requirements*" in the Liquidity and Capital Resources section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations." PGE believes that sufficient market supplies of coal are available to meet anticipated operations of Boardman for the foreseeable future.

Natural Gas

Port Westward and Beaver—PGE manages the price risk of natural gas supply for Port Westward through financial contracts up to 60 months in advance. Physical supplies for Port Westward and Beaver are generally purchased within 12 months of delivery and based on anticipated operation of the plants. PGE owns 79.5%, and is the operator of record, of the Kelso-Beaver Pipeline, which directly connects both generating plants to the Northwest Pipeline, an interstate natural gas pipeline operating between British Columbia and New Mexico. Currently, PGE transports gas on the Kelso-Beaver Pipeline for its own use under a firm transportation service agreement, with capacity offered to others on an interruptible basis to the extent not utilized by the Company. PGE has access to 103,305 Dth per day of firm gas transportation capacity to serve the two plants.

PGE also has contractual access through April 2017 to natural gas storage in Mist, Oregon, from which it can draw in the event that gas supplies are interrupted or if economic factors require its use. This storage may be used to fuel both Port Westward and Beaver. PGE believes that sufficient market supplies of gas are available to meet anticipated operations of both plants for the foreseeable future.

The Beaver generating plant has the capability to operate on No. 2 diesel fuel oil when it is economical or if the plant's natural gas supply is interrupted. PGE had an approximate 7-day supply of ultra-low sulfur diesel fuel oil at the plant site as of December 31, 2012. The current operating permit for Beaver limits the number of gallons of fuel oil that can be burned daily, which effectively limits the daily hours of operation of Beaver on fuel oil.

Coyote Springs—PGE manages the price risk of natural gas supply for Coyote Springs through financial contracts up to 60 months in advance, while physical supplies are generally purchased within 12 months of delivery and based on anticipated operation of the plant. Coyote Springs utilizes 41,000 Dth per day of natural gas when operating at full capacity, with firm transportation capacity on three pipeline systems accessing gas fields in Alberta, Canada. PGE believes that sufficient market supplies of gas are available for Coyote Springs for the foreseeable future, based on anticipated operation of the plant. Although Coyote Springs was designed to also operate on fuel oil, such capability has been deactivated in order to optimize natural gas operations.

Purchased Power

PGE supplements its own generation with power purchased in the wholesale market to meet its retail load requirements. The Company utilizes short- and long-term wholesale power purchase contracts in an effort to provide the most favorable economic mix on a variable cost basis. Such contracts have original terms ranging from one month to 53 years and expire at varying dates through 2055.

PGE's medium term power cost strategy helps mitigate the effect of price volatility on its customers due to changing energy market conditions. The strategy allows the Company to take positions in power and fuel markets up to five years in advance of physical delivery. By purchasing a portion of anticipated energy needs for future years over an extended period, PGE mitigates a portion of the potential future volatility in the average cost of purchased power and fuel.

The Company's major power purchase contracts consist of the following (also see the preceding table which summarizes the average resource capabilities related to these contracts):

Capacity/exchange—PGE has two contracts that provide PGE with firm capacity to help meet the Company's peak loads. The contract representing 10 MW of capacity expires in May 2014 and the contract representing 150 MW of capacity expires in December 2016.

Hydro—The Company has three contracts that provide for the purchase of power generated from hydroelectric projects with an aggregate capacity of 98 MW and which expire between 2015 and 2017. In addition, PGE has the following:

- *Mid-Columbia hydro*—PGE has long-term power purchase contracts with certain public utility districts in the state of Washington for a portion of the output of three hydroelectric projects on the mid-Columbia River. The contract representing 159 MW of capacity expires in 2018 and the contract representing 181 MW of capacity expires in 2052. Although the projects currently provide a total of 340 MW of capacity, actual energy received is dependent upon river flows.

- *Confederated Tribes*—PGE has a long-term agreement under which the Company purchases, at market prices, the Tribes' interest in the output of the Pelton/Round Butte hydroelectric project. Although the agreement provides 150 MW of capacity, actual energy received is dependent upon river flows. The term of the agreement coincides with the term of the FERC license for this project, which expires in 2055. The Tribes may elect to sell its output to another party with a one year notice to PGE.

Wind—PGE has three contracts that provide for the purchase of renewable wind-generated electricity and which extend to various dates between 2028 and 2035. Although these contracts provide a total of 39 MW of capacity, actual energy received is dependent upon wind conditions.

Solar—PGE has three agreements to purchase power generated from photovoltaic solar projects, which expire between 2036 and 2037. These projects have a combined generating capacity of 7 MW. In addition, the Company operates, and purchases power from four solar projects with an aggregate of approximately 6 MW of capacity.

Other—These primarily consist of long-term contracts to purchase power from various counterparties, including other Pacific Northwest utilities, over terms extending into 2031.

Short-term contracts—These contracts are for delivery periods of one month up to one year in length. They are entered into with various counterparties to provide additional firm energy to help meet the Company's load requirement.

PGE also utilizes spot purchases of power in the open market to secure the energy required to serve its retail customers. Such purchases are made under contracts that range in duration from 30 minutes to less than one month. For additional information regarding PGE's power purchase contracts, see Note 15, Commitments and Guarantees, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Future Energy Resource Strategy

PGE's most recent IRP (2009 IRP) was acknowledged by the OPUC in November 2010 and includes an action plan for the acquisition of new resources and a 20-year strategy that outlines long-term expectations for resource needs and portfolio performance. To meet the projected energy requirements, the IRP includes energy efficiency measures, new renewable resources, new transmission capability, new generation plants, and improvements to existing generation plants, as follows:

- Acquisition of 214 MWa of energy efficiency through continuation of Energy Trust of Oregon programs, with funding to be provided from the existing public purpose charge and through enabling legislation included in Oregon's RPS;
- Approximately 100 MWa of wind or other renewable resources necessary to meet requirements of Oregon's RPS by 2015;
- Transmission capacity additions to interconnect new and existing energy resources in eastern Oregon to PGE's service territory. For additional information on the Cascade Crossing Transmission Project (Cascade Crossing), see "*Capital Requirements and Financing*" in the Overview section contained in Item 7. —"Management's Discussion and Analysis of Financial Condition and Results of Operations";
- New natural gas generation facilities to help meet additional base load requirements estimated at 300 to 500 MW;
- New natural gas generation facilities to help meet peak capacity requirements estimated at up to 200 MW;
- Seasonal peaking resources, consisting of 200 MW of bi-seasonal (winter and summer) peaking supply and 150 MW of winter-only peaking supply; and
- Continued operations of the Boardman plant, including the addition of certain emissions controls and the continuation of coal-fired operation of the plant through 2020. For additional information about emissions controls for the Boardman plant, see "*Capital Requirements*" in the Liquidity and Capital Resources section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

In accordance with PGE's IRP and pursuant to the OPUC's competitive bidding guidelines, the Company issued two RFPs during 2012 for additional resources, with one for capacity and energy resources and another for renewable resources. The RFP for capacity and energy resources is seeking approximately 300 MW to 500 MW of baseload energy resources, 200 MW of year-round flexible and peaking resources, 200 MW of bi-seasonal peaking supply, and 150 MW of winter-only peaking supply. The flexible and peaking resources are expected to be available in the 2013 to 2015 timeframe, with the baseload energy resources expected to be available in the 2014 to 2017 timeframe. The RFP for renewable resources is seeking approximately 100 MWa of renewable resources, which would be expected to be available to meet PGE's 2015 requirements under Oregon's renewable energy standard.

PGE has evaluated the capacity and energy resources bids received. PGE's benchmark proposal was selected in the RFP seeking 200 MW of year-round flexible and peaking resources. See Port Westward Unit 2 in the Capital Requirements section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations." The Company is in the process of negotiations with the top bidder from the final short list for baseload energy resources. The bids on the final short list include power purchase agreements and PGE-ownership options. In addition, PGE is in the process of negotiating power purchase agreements for the seasonal peaking resources. Final resource selections are expected by mid-2013. The Company is evaluating renewable resources bids received, and expects a final short list by March 2013, with final resource selection by mid-2013. An independent evaluator selected by the OPUC is helping conduct the RFP and reviewing bids to ensure an objective and impartial process.

In November 2012, the Company filed an informational update to its 2009 IRP, for which PGE is not proposing any changes to its action plan and no action is required by the OPUC. PGE is required to file its next IRP by November 29, 2013.

Transmission and Distribution

Transmission systems deliver energy from generating facilities to distribution systems for final delivery to customers. PGE schedules energy deliveries over its transmission system in accordance with FERC requirements and operates one balancing authority area (an electric system bounded by interchange metering) in its service territory. In 2012, PGE delivered approximately 20 million megawatt hours (MWh) in its balancing authority area through approximately 1,100 circuit miles of transmission lines.

PGE's transmission system is part of the Western Interconnection, the regional grid in the western United States. The Western Interconnection includes the interconnected transmission systems of 11 western states, two Canadian provinces and parts of Mexico, and is subject to the reliability rules of the WECC and the NERC. PGE relies on transmission contracts with Bonneville Power Administration (BPA) to transmit a significant amount of the Company's generation to its distribution system. PGE's transmission system, together with contractual rights on other transmission systems, enables the Company to integrate and access generation resources to meet its customers' energy requirements. PGE's generation is managed on a coordinated basis to obtain maximum load-carrying capability and efficiency. The Company's transmission and distribution systems are located as follows:

- On property owned or leased by PGE;
- Under or over streets, alleys, highways and other public places, the public domain and national forests, and state lands under franchises, easements or other rights that are generally subject to termination;
- Under or over private property as a result of easements obtained primarily from the record holder of title; or
- Under or over Native American reservations under grant of easement by the Secretary of the Interior or lease or easement by Native American tribes.

PGE's wholesale transmission activities are regulated by the FERC. In accordance with its OATT, PGE offers several transmission services to wholesale customers:

- Network integration transmission service, a service that integrates generating resources to serve retail loads;
- Short- and long-term firm point-to-point transmission service, a service with fixed delivery and receipt points; and
- Non-firm point-to-point service, an "as available" service with fixed delivery and receipt points.

These services are offered on a non-discriminatory basis, with all potential customers provided equal access to PGE's transmission system in accordance with FERC Standards of Conduct.

PGE's current acknowledged IRP includes a proposal for a 500 kV transmission line referred to as the Cascade Crossing Transmission Project, or Cascade Crossing, that would help meet future electricity demand. The project would transmit power from new and existing energy resources in northeastern Oregon to the Company's service territory. For additional information, see "Capital and Financing" in the Overview section of Item 7. —"Management's Discussion and Analysis of Financial Condition and Results of Operations."

PGE continues to meet state regulatory requirements related to power distribution service quality and reliability. Such requirements are reflected in specific indices that measure outage duration, outage frequency, and momentary power interruptions. The Company is required to include performance results related to service quality measures in annual reports filed with the OPUC. Specific monetary penalties can be assessed for failure to attain required performance levels, with amounts dependent upon the extent to which actual results fail to meet such requirements.

For additional information regarding the Company's transmission and distribution facilities, see "*Transmission and Distribution*" in Item 2.—"Properties."

Environmental Matters

PGE's operations are subject to a wide range of environmental protection laws and regulations, which pertain to air and water quality, endangered species and wildlife protection, and hazardous material. Various state and federal agencies regulate environmental matters that relate to the siting, construction, and operation of generation, transmission, and substation facilities and the handling, accumulation, cleanup, and disposal of toxic and hazardous substances. In addition, certain of the Company's hydroelectric projects and transmission facilities are located on property under the jurisdiction of federal and state agencies, and/or tribal entities that have authority in environmental protection matters. The following discussion provides further information on certain regulations that affect the Company's operations and facilities.

Air Quality

Clean Air Act—PGE's operations, primarily its thermal generating plants, are subject to regulation under the federal Clean Air Act (CAA), which addresses, among other things, particulate matter, hazardous air pollutants, and greenhouse gas emissions (GHGs). Oregon and Montana, the states in which PGE facilities are located, also implement and administer certain portions of the CAA and have set standards that are at least equal to federal standards.

In December 2011, the EPA issued new emissions limits under the CAA's National Emission Standards for Hazardous Air Pollutants (NESHAP) to regulate air emissions from coal- and oil-fired electric generating units. Emission limits included in the NESHAP are based on the application of maximum achievable control technology (MACT). The Company believes the Boardman plant should meet the MACT requirements without additional capital investment, once installation of the emissions controls already anticipated to meet the revised rules for SO_2 and NO_x emissions at Boardman is complete. Those anticipated controls include a Dry Sorbent Injection system to be added to Boardman in 2014, at an estimated capital cost to the Company of $27 million, including allowance for funds used during construction (AFDC). DEQ rules provide for coal-fired operation at Boardman to cease no later than December 31, 2020.

The operator of the Colstrip plant has provided the Company with estimated costs for emissions control modifications to Units 3 and 4 that may be necessary to meet the MACT requirements at Colstrip. Based on this estimate, the Company expects that its share of these costs, as a 20% owner of Units 3 and 4, will not exceed $10 million.

Although regulation of mercury emissions is contemplated under NESHAP, the states of Oregon and Montana have previously adopted regulations concerning mercury emissions. Both Boardman and Colstrip meet the mercury compliance requirements in their respective states.

PGE manages its air emissions by the use of low sulfur fuel, emissions and combustion controls and monitoring, and SO_2 allowances awarded under the CAA. The current allowance inventory and expected future annual SO_2 allowances, along with the recent and planned installation of emissions controls, are anticipated to be sufficient to permit the Company to continue to meet its compliance requirements and operate its thermal generating plants at forecasted capacity for at least the next several years.

Climate Change—No comprehensive GHG emissions legislation has been considered and voted on by Congress since 2009. However, state, regional, and federal legislative efforts continue with respect to establishing regulation of greenhouse gas (GHG) emissions and their potential impacts on climate change. The EPA has taken the lead role on climate change policy utilizing existing authority under the CAA to develop regulations. Areas of focus for the Company include the following:

- In December 2010, the EPA announced a proposed settlement agreement with states and environmental groups that would require the EPA to set GHG New Source Performance Standards (NSPS) for new and modified fossil fuel-based power plants, and guidelines for state-developed NSPS for existing sources. The emissions standard for new gas and coal fired electric generating units was proposed in April 2012 and is expected to be finalized in the second quarter of 2013. EPA is also expected to propose guidance for state-developed NSPS for existing sources, including modified sources, in 2013.

- The State of Oregon has established a non-binding policy guideline that sets a goal to reduce GHG emissions to 10% below 1990 levels by 2020. Although the guideline does not mandate reductions by any specific entity nor include penalties for failure to meet the goal, the Company is required to report to the DEQ the amount of GHG emissions produced along with the total amount of energy produced or purchased by PGE for consumption in Oregon.
- During 2012, the Company submitted the first required GHG emissions report applicable to its transmission and distribution system to both the EPA and the DEQ.

Any laws that would impose emissions taxes or mandatory reductions in GHG emissions may have a material impact on PGE's operations, as the Company utilizes fossil fuels in its own power generation and other companies use such fuels to generate power that PGE purchases in the wholesale market. PGE's Beaver, Coyote Springs, and Port Westward natural gas-fired facilities, and the Company's ownership interest in Boardman and Colstrip coal-fired facilities, provide approximately 66% of the Company's net generating capacity. If PGE were to incur incremental costs as a result of changes in the regulations regarding GHGs, the Company would seek recovery in customer prices.

Water Quality

The federal Clean Water Act requires that any federal license or permit to conduct an activity that may result in a discharge to waters of the United States must first receive a water quality certification from the state in which the activity will occur. In Oregon and Montana, the Departments of Environmental Quality are responsible for reviewing proposed projects under this requirement to ensure that federally approved activities will meet water quality standards and policies established by the respective state. PGE has obtained permits where required, and has certificates of compliance for its hydroelectric operations under the FERC licenses.

Threatened and Endangered Species and Wildlife

Fish Protection—The federal Endangered Species Act (ESA) has granted protection to many populations of migratory fish species in the Pacific Northwest that have declined significantly over the last several decades. Long-term recovery plans for these species have caused major operational changes to many of the region's hydroelectric projects. PGE purchases power in the wholesale market to serve its retail load requirements and has contracts to purchase power generated at some of the affected facilities on the mid-Columbia River in central Washington.

PGE is implementing a series of fish protection measures at its hydroelectric projects on the Clackamas, Deschutes, and Willamette rivers that were prescribed by the U.S. Fish and Wildlife Service and the National Marine Fisheries Service under their authority granted in the ESA and the Federal Power Act. As a result of measures contained in their operating licenses, the Deschutes River and Willamette River projects have been certified as low impact hydro, with 50 MWa of their output included as part of the Company's renewable energy portfolio used to meet the requirements of Oregon's RPS. Conditions required with the operating licenses are expected to result in a minor reduction in power production and increase capital spending to modify the facilities to enhance fish passage and survival.

Avian Protection—Various statutory authorities as well as the Migratory Bird Treaty Act have established civil, criminal, and administrative penalties for the unauthorized take of migratory birds. Because PGE operates electric transmission lines and wind generation facilities that can pose risks to a variety of such birds, the Company is required to have an avian protection plan to reduce risks to bird species that can result from Company operations. PGE has developed and implemented such a plan for its transmission and distribution facilities and continues the process of developing a plan for its wind facilities.

Hazardous Waste

PGE has a comprehensive program to comply with requirements of both federal and state regulations related to hazardous waste storage, handling, and disposal. The handling and disposal of hazardous waste from Company facilities is subject to regulation under the federal Resource Conservation and Recovery Act (RCRA). In addition, the use, disposal, and clean-up of polychlorinated biphenyls, contained in certain electrical equipment, are regulated under the federal Toxic Substances Control Act.

The Company's coal-fired generation facilities, Boardman and Colstrip, produce coal combustion byproducts (CCBs), which have historically not been considered hazardous waste under the RCRA. The EPA continues to consider listing these residuals as hazardous wastes, which would likely have an impact on current disposal practices and could increase the Company's cost of handling these materials. A number of legislative initiatives and challenges are underway to limit or remove the EPA's ability to regulate CCBs as hazardous waste. The Company cannot predict the possible impact of this matter until the EPA provides further guidance on the proposed rules. If PGE were to incur incremental costs as a result of changes in the regulations, the Company would seek recovery in customer prices.

PGE is also subject to regulation under the Comprehensive Environmental Response Compensation and Liability Act (CERCLA), commonly referred to as Superfund. The CERCLA provides authority to the EPA to assert joint and several liability for investigation and remediation costs for designated Superfund sites. The EPA lists PGE as a Potentially Responsible Party (PRP) on two Superfund sites as follows:

Portland Harbor—A 1997 investigation by the EPA of a segment of the Willamette River known as the Portland Harbor revealed significant contamination of river sediments and prompted the EPA to subsequently include Portland Harbor on the federal National Priority List as a Superfund site pursuant to CERCLA. The EPA initially listed sixty-nine PRPs, including PGE as it has historically owned or operated property near the river. In 2008, the EPA requested further information from various parties, including PGE, concerning property several miles beyond the original river segment and, as a result, the PRPs now number over one hundred. In March 2012, a draft feasibility study was submitted to the EPA for review and approval. A record of Decision is expected from the EPA in 2015 on the various clean-up alternatives, which, as outlined in the feasibility study, could take up to 28 years to complete and range in cost from $169 million to $1.8 billion. It is unclear for what portion, if any, that PGE might be held responsible.

Harbor Oil—The Harbor Oil site in north Portland is the location of a company that PGE engaged to process used oil from power plants and electrical distribution systems until 2003. The Harbor Oil facility continues to be utilized by other entities for the processing of used oil and other lubricants. In September 2003, the Harbor Oil site was included on the federal National Priority List as a federal Superfund site and PGE was included among fourteen PRPs. In March 2012, the EPA approved the remedial investigation and stated that it intends to recommend no action on the site. A final Record of Decision is expected in March 2013.

For additional information on these EPA actions, see Note 18, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Under the Nuclear Waste Policy Act of 1982, the USDOE is responsible for the permanent storage and disposal of spent nuclear fuel. PGE has contracted with the USDOE for permanent disposal of spent nuclear fuel from Trojan that is stored in the Independent Spent Fuel Storage Installation (ISFSI), an NRC-licensed interim dry storage facility that houses the fuel at the former plant site. The spent nuclear fuel is expected to remain in the ISFSI until permanent off-site storage is available, which is not likely to be before 2020. Shipment of the spent nuclear fuel from the ISFSI to off-site storage is not expected to be completed prior to 2033. For additional information regarding this matter, see "*Trojan decommissioning activities*" in Note 7, Asset Retirement Obligations, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

ITEM 1A. RISK FACTORS.

Certain risks and uncertainties that could have a significant impact on PGE's business, financial condition, results of operations or cash flows, or that may cause the Company's actual results to vary from the forward-looking statements contained in this Annual Report on Form 10-K, include, but are not limited to, those set forth below.

Recovery of PGE's costs is subject to regulatory review and approval, and the inability to recover costs may adversely affect the Company's results of operations.

The prices that PGE charges for its retail services, as authorized by the OPUC, are a major factor in determining the Company's operating income, financial position, liquidity, and credit ratings. As a general matter, the Company seeks to recover in customer prices most of the costs incurred in connection with the operation of its business, including, among other things, costs related to capital projects (such as the construction of new facilities or the modification of existing facilities), the costs of compliance with legislative and regulatory requirements and the costs of damage from storms and other natural disasters. However, there can be no assurance that such recovery will be granted. The OPUC has the authority to disallow the recovery of any costs that it considers imprudently incurred. Although the OPUC is required to establish customer prices that are fair, just and reasonable, it has significant discretion in the interpretation of this standard.

In February 2013, PGE filed with the OPUC a 2014 General Rate Case with a 2014 test year. For additional information regarding the 2014 General Rate Case, see the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations." In both PGE's 2009 and 2011 general rate cases, overall price increases approved by the OPUC were less than the Company's initial proposals. Under such circumstances, PGE attempts to manage its costs at levels consistent with the reduced price increases. However, if the Company is unable to do so, or if such cost management results in increased operational risk, the Company's financial and operating results could be adversely affected.

Economic conditions that result in reduced demand for electricity and impair the financial stability of some of PGE's customers, could affect the Company's results of operations.

Unfavorable economic conditions in Oregon may result in reduced demand for electricity. Such reductions in demand could adversely affect the Company's results of operations and cash flows. Economic conditions could also result in an increased level of uncollectable customer accounts and cause the Company's vendors and service providers to experience cash flow problems and be unable to perform under existing or future contracts.

Market prices for power and natural gas are subject to forces that are often not predictable and which can result in price volatility and general market disruption, adversely affecting PGE's costs and ability to manage its energy portfolio and procure required energy supply, which ultimately could have an adverse effect on the Company's liquidity and results of operations.

As part of its normal business operations, PGE purchases power and natural gas in the open market under short and long term contracts, which may specify variable-prices or volumes. Market prices for power and natural gas are influenced primarily by factors related to supply and demand. These factors generally include the adequacy of generating capacity, scheduled and unscheduled outages of generating facilities, hydroelectric generation levels, prices and availability of fuel sources for generation, disruptions or constraints to transmission facilities, weather conditions, economic growth, and changes in technology.

Volatility in these markets can affect the availability, price and demand for power and natural gas. Disruption in power and natural gas markets could result in a deterioration of market liquidity, increase the risk of counterparty default, affect regulatory and legislative processes in unpredictable ways, affect wholesale power prices, and impair PGE's ability to manage its energy portfolio. Changes in power and natural gas prices can also affect the fair value of derivative instruments and cash requirements to purchase power and natural gas. If power and natural gas prices decrease from those contained in the Company's existing purchased power and natural gas agreements, PGE may be required to provide increased collateral, which could adversely affect the Company's liquidity. Conversely, if power and natural gas prices rise, especially during periods when the Company requires greater-than-expected volumes that must be purchased at market or short-term prices, PGE could incur greater costs than originally estimated.

The risk of volatility in power costs is partially mitigated through the Annual Power Cost Update Tariff (AUT) and the PCAM. PGE files an annual AUT with an update of PGE's forecasted net variable power costs (baseline NVPC) to be reflected in customer prices. The PCAM provides a mechanism by which the Company can adjust future customer prices to reflect a portion of the difference between each year's baseline NVPC included in customer prices and actual NVPC. PGE is subject to a portion of the business risk or benefit associated with the difference between actual NVPC and baseline NVPC by application of an asymmetrical "deadband." The PCAM provides for a fixed deadband range of $15 million below, to $30 million above, baseline NVPC. Application of the PCAM requires that PGE absorb certain power cost increases before the Company is allowed to recover any amount from customers. Accordingly, the PCAM is expected to only partially mitigate the potentially adverse financial impacts of forced generating plant outages, reduced hydro and wind availability, interruptions in fuel supplies, and volatile wholesale energy prices.

The effects of weather on electricity usage can adversely affect results of operations.

Weather conditions can adversely affect PGE's revenues and costs, impacting the Company's results of operations. Variations in temperatures can affect customer demand for electricity, with warmer-than-normal winters or cooler-than-normal summers reducing the demand for energy. Weather conditions are the dominant cause of usage variations from normal seasonal patterns, particularly for residential customers. Severe weather can also disrupt energy delivery and damage the Company's transmission and distribution system.

Rapid increases in load requirements resulting from unexpected adverse weather changes, particularly if coupled with transmission constraints, could adversely impact PGE's cost and ability to meet the energy needs of its customers. Conversely, rapid decreases in load requirements could result in the sale of excess energy at depressed market prices.

Forced outages at PGE's generating plants can increase the cost of power required to serve customers because the cost of replacement power purchased in the wholesale market generally exceeds the Company's cost of generation.

Forced outages at the Company's generating plants could result in power costs greater than those included in customer prices. As indicated above, application of the Company's PCAM could help mitigate adverse financial impacts of such outages; however, the cost sharing features of the mechanism do not provide full recovery in customer prices. Inability to recover such costs in future prices could have a negative impact on the Company's results of operations.

The construction of new facilities, or modifications to existing facilities, is subject to risks that could result in the disallowance of certain costs for recovery in customer prices or higher operating costs.

PGE's current position as a "short" utility requires that the Company supplement its own generation with wholesale power purchases to meet its retail load requirement. In addition, long-term increases in both the number of customers and demand for energy will require continued expansion and upgrade of PGE's generation, transmission, and distribution systems. Construction of new facilities and modifications to existing facilities could be affected by various factors, including unanticipated delays and cost increases and the failure to obtain, or delay in obtaining, necessary permits from state or federal agencies or tribal entities, which could result in failure to complete the projects and the disallowance of certain costs in the rate determination process. In addition, failure to complete construction projects according to specifications could result in reduced plant efficiency, equipment failure, and plant performance that falls below expected levels, which could increase operating costs.

Adverse changes in PGE's credit ratings could negatively affect its access to the capital markets and its cost of borrowed funds.

Access to capital markets is important to PGE's ability to operate its business and complete its capital projects. Credit rating agencies evaluate PGE's credit ratings on a periodic basis and when certain events occur. A ratings downgrade could increase the interest rates and fees on PGE's revolving credit facilities, increasing the cost of funding day-to-day working capital requirements, and could also result in higher interest rates on future long-term debt. A ratings downgrade could also restrict the Company's access to the commercial paper market, a principal source of short-term financing, or result in higher interest costs.

In addition, if Moody's Investors Service (Moody's) and/or Standard and Poor's Ratings Services (S&P) reduce their rating on PGE's unsecured debt to below investment grade, the Company could be subject to requests by certain wholesale counterparties to post additional performance assurance collateral, which could have an adverse effect on the Company's liquidity.

Current capital and credit market conditions could adversely affect the Company's access to capital, cost of capital, and ability to execute its strategic plan as currently scheduled.

Access to capital and credit markets is important to PGE's ability to operate. The Company potentially faces significant capital requirements over the next two to five years and expects to issue debt and equity securities, as necessary, to fund these requirements. In addition, contractual commitments and regulatory requirements may limit the Company's ability to delay or terminate certain projects. For additional information concerning PGE's capital requirements, see "*Capital Requirements*" in the Liquidity and Capital Resources section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

If the capital and credit market conditions in the United States and other parts of the world deteriorate, the Company's future cost of debt and equity capital, as well as access to capital markets, could be adversely affected. In addition, restrictions on PGE's ability to access capital markets could affect its ability to execute its strategic plan.

PGE is subject to various legal and regulatory proceedings, the outcome of which is uncertain, and resolution unfavorable to PGE could adversely affect the Company's results of operations, financial condition or cash flows.

From time to time in the normal course of its business, PGE is subject to various regulatory proceedings, lawsuits, claims and other matters, which could result in adverse judgments, settlements, fines, penalties, injunctions, or other relief. These matters are subject to many uncertainties, the ultimate outcome of which management cannot predict. The final resolution of certain matters in which PGE is involved could require that the Company incur expenditures over an extended period of time and in a range of amounts that could have an adverse effect on its cash flows and results of operations. Similarly, the terms of resolution could require the Company to change its business practices and procedures, which could also have an adverse effect on its cash flows, financial position or results of operations.

There are certain pending legal and regulatory proceedings, such as those related to PGE's recovery of its investment in Trojan, the proceedings related to refunds on wholesale market transactions in the Pacific Northwest and the investigation and any resulting remediation efforts related to the Portland Harbor site, that may have an adverse effect on results of operations and cash flows for future reporting periods. For additional information, see Item 3.—"Legal Proceedings" and Note 18, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Reduced stream flows and unfavorable wind conditions can adversely affect generation from hydroelectric and wind resources. The Company could be required to replace generation from these sources with higher cost power from other facilities or with wholesale market purchases, which could have an adverse effect on results of operations.

PGE derives a significant portion of its power supply from its own hydroelectric facilities and through long-term purchase contracts with certain public utility districts in the state of Washington. Regional rainfall and snow pack levels affect stream flows and the resulting amount of generation available from these facilities. Shortfalls in low-cost hydro production would require increased generation from the Company's higher cost thermal plants and/or power purchases in the wholesale market, which could have an adverse effect on results of operations.

PGE also derives a portion of its power supply from wind resources, for which the output is dependent upon wind conditions. Unfavorable wind conditions could require increased reliance on power from the Company's other generating resources or power purchases in the wholesale market, both of which could have an adverse effect on results of operations.

Although the application of the PCAM could help mitigate adverse financial effects from any decrease in power provided by hydroelectric and wind resources, full recovery of any increase in power costs is not assured. Inability to fully recover such costs in future prices could have a negative impact on the Company's results of operations, as well as a reduction in renewable energy credits and loss of production tax credits (PTCs) related to wind resources.

Legislative or regulatory efforts to reduce greenhouse gas emissions could lead to increased capital and operating costs and have an adverse impact on the Company's results of operations.

Future legislation or regulations could result in limitations on greenhouse gas emissions from the Company's fossil fuel-fired generation facilities. Compliance with any greenhouse gas emission reduction requirements could require PGE to incur significant expenditures, including those related to carbon capture and sequestration technology, purchase of emission allowances and offsets, fuel switching, and the replacement of high-emitting generation facilities with lower emitting facilities.

The cost to comply with potential greenhouse gas emissions reduction requirements is subject to significant uncertainties, including those related to: the timing of the implementation of emissions reduction rules; required levels of emissions reductions; requirements with respect to the allocation of emissions allowances; the maturation, regulation and commercialization of carbon capture and sequestration technology; and PGE's compliance alternatives. Although the Company cannot currently estimate the effect of future legislation or regulations on its results of operations, financial condition or cash flows, the costs of compliance with such legislation or regulations could be material.

Under certain circumstances, banks participating in PGE's credit facilities could decline to fund advances requested by the Company or could withdraw from participation in the credit facilities.

PGE currently has unsecured revolving credit facilities with several banks for an aggregate amount of $700 million. These credit facilities are available for general corporate purposes and may be used to supplement operating cash flow and provide a primary source of liquidity. The credit facilities may also be used as backup for commercial paper borrowings.

The credit facilities represent commitments by the participating banks to make loans and, in certain cases, to issue letters of credit. The Company is required to make certain representations to the banks each time it requests an advance under one of the credit facilities. However, in the event certain circumstances occur that could result in a material adverse change in the business, financial condition or results of operations of PGE, the Company may not be able to make such representations, in which case the banks would not be required to lend. PGE is also subject to the risk that one or more of the participating banks may default on their obligation to make loans under the credit facilities.

In addition, it is possible that the Company might not be aware of certain developments at the time it makes such a representation in connection with a request for a loan, which could cause the representation to be untrue at the time made and constitute an event of default. Such a circumstance could result in a loss of the banks' commitments under the credit facilities and, in certain circumstances, the accelerated repayment of any outstanding loan balances.

Measures required to comply with state and federal regulations related to air emissions and water discharges from thermal generating plants could result in increased capital expenditures and operating costs and reduce generating capacity, which could adversely affect the Company's results of operations.

The Company is subject to state and federal requirements concerning air emissions and water discharges from thermal generation plants. For additional information, see the Environmental Matters section in Item 1. —"Business." These requirements could adversely affect the Company's results of operations by requiring (i) the installation of additional air emissions and water discharge controls at the Company's generating plants, which could result in increased capital expenditures and (ii) changes to PGE's operations that could increase operating costs and reduce generating capacity.

Adverse capital market performance could result in reductions in the fair value of benefit plan assets and increase the Company's liabilities related to such plans. Sustained declines in the fair value of the plans' assets could result in significant increases in funding requirements, which could adversely affect PGE's liquidity and results of operations.

Performance of the capital markets affects the value of assets that are held in trust to satisfy future obligations under the Company's defined benefit pension plan. Sustained adverse market performance could result in lower rates of return for these assets than projected by the Company and could increase PGE's funding requirements related to the pension plan. Additionally, changes in interest rates affect the Company's liabilities under the pension plan. As interest rates decrease, the Company's liabilities increase, potentially requiring additional funding. In 2012, discount rates used to value the pension plan declined substantially. This decline, combined with an increased actuarial loss related to prior year asset under performance, contributed to an increase in the pension plan's underfunded status from $147 million as of December 31, 2011 to $191 million as of December 31, 2012.

Performance of the capital markets also affects the fair value of assets that are held in trust to satisfy future obligations under the Company's non-qualified employee benefit plans, which include deferred compensation plans. As changes in the fair value of these assets are recorded in current earnings, decreases can adversely affect the Company's operating results. In addition, such decreases can require that PGE make additional payments to satisfy its obligations under these plans.

For additional information regarding PGE's contribution obligations under its pension and non-qualified benefit plans, see "*Contractual Obligations and Commercial Commitments*" in the Liquidity and Capital Resources section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations," and "*Pension and Other Postretirement Plans*" in Note 10, Employee Benefits, in the Notes to Consolidated Financial Statements in Item 8.— "Financial Statements and Supplementary Data."

Failure of PGE's wholesale suppliers to perform their contractual obligations could adversely affect the Company's ability to deliver electricity and increase the Company's costs.

PGE relies on suppliers to deliver natural gas, coal and electricity, in accordance with short- and long-term contracts. Failure of suppliers to comply with such contracts in a timely manner could disrupt PGE's ability to deliver electricity and require the Company to incur additional expenses to meet the needs of its customers. In addition, as these contracts expire, PGE could be unable to continue to purchase natural gas, coal or electricity on terms and conditions equivalent to those of existing agreements.

Operational changes required to comply with both existing and new environmental laws related to fish and wildlife could adversely affect PGE's results of operations.

A portion of PGE's total energy requirement is supplied with power generated from hydroelectric and wind projects. Operation of these projects is subject to regulation related to the protection of fish and wildlife. The listing of various species of salmon, wildlife, and plants as threatened or endangered has resulted in significant operational changes to these projects. Salmon recovery plans could include further major operational changes to the region's hydroelectric projects, including those owned by PGE and those from which the Company purchases power under long-term contracts. In addition, laws relating to the protection of migratory birds and other wildlife could impact the development and operation of transmission lines and wind projects. Also, new interpretations of existing laws and regulations could be adopted or become applicable to such facilities, which could further increase required expenditures for salmon recovery and endangered species protection and reduce the amount of hydro or wind generation available to meet the Company's energy requirements.

PGE could be vulnerable to cyber security attacks, data security breaches or other similar events that could disrupt its operations, require significant expenditures or result in claims against the Company.

In the normal course of business, PGE collects, processes and retains sensitive and confidential customer and employee information, as well as proprietary business information, and operates systems that directly impact the availability of electric power and the transmission of electric power in its service territory. Despite the security measures in place, the Company's systems, and those of third-party service providers, could be vulnerable to cyber security attacks, data security breaches or other similar events that could disrupt operations or result in the release of sensitive or confidential information. Such events could cause a shutdown of service or expose the Company to liability. In addition, the Company may be required to expend significant capital and other resources to protect against security breaches or to alleviate problems caused by security breaches. The Company maintains insurance coverage against some, but not all, potential losses resulting from these risks. However, insurance may not be adequate to protect the Company against liability in all cases. In addition, PGE is subject to the risk that insurers will dispute or be unable to perform their obligations to the Company.

Storms and other natural disasters could damage the Company's facilities and disrupt delivery of electricity resulting in significant property loss, repair costs, and reduced customer satisfaction.

The Company has exposure to natural disasters that can cause significant damage to its generation, transmission, and distribution facilities. Such events can interrupt the delivery of electricity, increase repair and service restoration expenses, and reduce revenues. Such events, if repeated or prolonged, can also affect customer satisfaction and the level of regulatory oversight. As a regulated utility, the Company is required to provide service to all customers within its service territory and generally has been afforded liability protection against customer claims related to service failures beyond the Company's reasonable control.

In PGE's 2011 General Rate Case, the OPUC authorized the Company to collect $2 million annually from retail customers for such damages and to defer any amount not utilized in the current year. The deferred amount, along with the annual collection, would be available to offset potential storm damage costs in future years.

PGE utilizes insurance, when possible, to mitigate the cost of physical loss or damage to the Company's property. As cost effective insurance coverage for transmission and distribution line property (poles and wires) is currently not available, however, the Company would likely seek recovery of large losses to such property through the ratemaking process.

PGE is subject to extensive regulation that affects the Company's operations and costs.

PGE is subject to regulation by the FERC, the OPUC, and by certain federal, state and local authorities under environmental and other laws. Such regulation significantly influences the Company's operating environment and can have an effect on many aspects of its business. Changes to regulations are ongoing, and the Company cannot predict with certainty the future course of such changes or the ultimate effect that they might have on its business.

However, changes in regulations could delay or adversely affect business planning and transactions, and substantially increase the Company's costs.

PGE has a workforce with a significant number of employees approaching retirement.

The Company anticipates higher averages of retirement rates over the next ten years and will likely need to replace a significant number of employees in key positions. PGE's ability to successfully implement a workforce succession plan is dependent upon the Company's ability to employ and retain skilled professional and technical workers. Without a skilled workforce, the Company would face greater challenges in providing quality service to its customers and meeting regulatory requirements, both of which could affect operating results.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES.

PGE's principal property, plant, and equipment are located on land owned by the Company or land under the control of the Company pursuant to existing leases, federal or state licenses, easements or other agreements. In some cases, meters and transformers are located on customer property. The Company leases its corporate headquarters complex, located in Portland, Oregon. The Indenture securing the Company's First Mortgage Bonds constitutes a direct first mortgage lien on substantially all utility property and franchises, other than expressly excepted property.

Generating Facilities

The following are generating facilities owned by PGE as of December 31, 2012:

Facility	Location	Net Capacity (1)	
Wholly-owned:			
Hydro:			
Faraday	Clackamas River	46	MW
North Fork	Clackamas River	58	
Oak Grove	Clackamas River	44	
River Mill	Clackamas River	25	
T.W. Sullivan	Willamette River	18	
Natural Gas/Oil:			
Beaver	Clatskanie, Oregon	516	
Port Westward	Clatskanie, Oregon	410	
Coyote Springs	Boardman, Oregon	246	
Wind:			
Biglow Canyon	Sherman County, Oregon	450	
Jointly-owned (2):			
Coal:			
Boardman (3)	Boardman, Oregon	374	
Colstrip (4)	Colstrip, Montana	296	
Hydro:			
Pelton (5)	Deschutes River	73	
Round Butte (5)	Deschutes River	225	
Total net capacity		2,781	MW

(1) Represents net capacity of generating unit as demonstrated by actual operating or test experience, net of electricity used in the operation of a given facility. For wind-powered generating facilities, nameplate ratings are used in place of net capacity. A generator's nameplate rating is its full-load capacity under normal operating conditions as defined by the manufacturer.

(2) Reflects PGE's ownership share.

(3) PGE operates Boardman and has a 65% ownership interest.

(4) PPL Montana, LLC operates Colstrip and PGE has a 20% ownership interest.

(5) PGE operates Pelton and Round Butte and has a 66.67% ownership interest.

PGE's hydroelectric projects are operated pursuant to FERC licenses issued under the Federal Power Act. The licenses for the hydroelectric projects on the three different rivers expire as follows: Clackamas River, 2055; Willamette River, 2035; and Deschutes River, 2055.

Transmission and Distribution

PGE owns and/or has contractual rights associated with transmission lines that deliver electricity from its Oregon generation facilities to its distribution system in its service territory and also to the Western Interconnection. As of December 31, 2012, PGE owned an electric transmission system consisting of approximately 700 circuit miles of 500-kV line and 400 circuit miles of 230-kV line. The Company also has approximately 24,000 circuit miles of primary and secondary distribution lines that deliver electricity to its customers.

The Company also has an ownership interest in the following transmission facilities:

- Approximately 14% of the Montana Intertie from the Colstrip plant in Montana to BPA's transmission system; and
- Approximately 19% of the California-Oregon AC Intertie, a 4,800 MW transmission facility between John Day, in northern Oregon, and Malin, in southern Oregon near the California border. The California-Oregon AC Intertie is used primarily for the transmission of interstate purchases and sales of electricity among utilities, including PGE.

In addition, the Company has contractual rights to the following transmission capacity:

- Approximately 3,100 MW of firm BPA transmission from remote resources and markets on BPA's system to PGE's service territory in Oregon; and
- 200 MW of firm BPA transmission from mid-Columbia projects in Washington to the northern end of the California-Oregon AC Intertie, near John Day, Oregon, and 100 MW to the northern end of the Pacific DC Intertie, near Celilo, Oregon.

ITEM 3. LEGAL PROCEEDINGS.

Citizens' Utility Board of Oregon v. Public Utility Commission of Oregon and Utility Reform Project and Colleen O'Neill v. Public Utility Commission of Oregon, Public Utility Commission of Oregon Docket Nos. DR 10, UE 88, and UM 989, Marion County Oregon Circuit Court, Case No. 94C-10417, the Court of Appeals of the State of Oregon, the Oregon Supreme Court, Case No. SC S45653.

PGE, in its 1993 general rate filing, sought OPUC approval to recover through rates future decommissioning costs and full recovery of, and a rate of return on, its Trojan investment. PGE's request was challenged, but in August 1993, the OPUC issued a Declaratory Ruling in PGE's favor. The Citizens' Utility Board (CUB) appealed the decision to the Oregon Court of Appeals.

In PGE's 1995 general rate case, the OPUC issued an order (1995 Order) granting PGE full recovery of Trojan decommissioning costs and 87% of its remaining undepreciated investment in the plant. The Utility Reform Project (URP) filed an appeal of the 1995 Order to the Marion County Circuit Court. The CUB also filed an appeal to the Marion County Circuit Court challenging the portion of the 1995 Order that authorized PGE to recover a return on its remaining undepreciated investment in Trojan.

In April 1996, the Marion County Circuit Court issued a decision that found that the OPUC could not authorize PGE to collect a return on its undepreciated investment in Trojan. The 1996 decision was appealed to the Oregon Court of Appeals.

In June 1998, the Oregon Court of Appeals ruled that the OPUC did not have the authority to allow PGE to recover a rate of return on its undepreciated investment in Trojan. The court remanded the matter to the OPUC for reconsideration of its 1995 Order in light of the court's decision.

In September 2000, PGE, CUB, and the OPUC Staff settled proceedings related to PGE's recovery of its investment in the Trojan plant (Settlement). The URP did not participate in the Settlement and filed a complaint with the OPUC, challenging PGE's application for approval of the accounting and ratemaking elements of the Settlement.

In March 2002, the OPUC issued an order (Settlement Order) denying all of the URP's challenges and approving PGE's application for the accounting and ratemaking elements of the Settlement. The URP appealed the Settlement Order to the Marion County Circuit Court. Following various appeals and proceedings, the Oregon Court of Appeals issued an opinion in October 2007 that reversed the Settlement Order and remanded the Settlement Order to the OPUC for reconsideration.

As a result of its reconsideration of the Settlement Order, the OPUC issued an order in September 2008 that required PGE to refund $33.1 million to customers. The Company completed the distribution of the refund to customers, plus accrued interest, as required.

In October 2008, the URP and the Class Action Plaintiffs (described in the Dreyer proceeding below) separately appealed the September 2008 OPUC order to the Oregon Court of Appeals. On February 6, 2013, the Oregon Court of Appeals issued an opinion that upheld the September 2008 OPUC order.

Dreyer, Gearhart and Kafoury Bros., LLC v. Portland General Electric Company, Marion County Circuit Court, Case No. 03C 10639; and Morgan v. Portland General Electric Company, Marion County Circuit Court, Case No. 03C 10640.

In January 2003, two class action suits were filed in Marion County Circuit Court against PGE. The Dreyer case seeks to represent current PGE customers that were customers during the period from April 1, 1995 to October 1, 2000 (Current Class) and the Morgan case seeks to represent PGE customers that were customers during the period from April 1, 1995 to October 1, 2000, but who are no longer customers (Former Class, together with the Current Class, the Class Action Plaintiffs). The suits seek damages of $190 million plus interest for the Current Class and $70 million plus interest for the Former Class, from the inclusion of a return on investment of Trojan in the rates PGE charged its customers.

In April 2004, the Class Action Plaintiffs filed a Motion for Partial Summary Judgment and in July 2004, PGE also moved for Summary Judgment in its favor on all of the Class Action Plaintiffs' claims. In December 2004, the Judge granted the Class Action Plaintiffs' motion for Class Certification and Partial Summary Judgment and denied PGE's motion for Summary Judgment. In March 2005, PGE filed two Petitions with the Oregon Supreme Court asking the Court to take jurisdiction and command the trial Judge to dismiss the complaints, or to show cause why they should not be dismissed, and seeking to overturn the Class Certification.

In August 2006, the Oregon Supreme Court issued a ruling on PGE's Petitions abating these class action proceedings until the OPUC responded with respect to the certain issues that had been remanded to the OPUC by the Marion County Circuit Court in the proceeding described above.

In October 2006, the Marion County Circuit Court issued an Order of Abatement in response to the ruling of the Oregon Supreme Court, abating the class actions for one year.

In October 2007, the Class Action Plaintiffs filed a Motion with the Marion County Circuit Court to lift the abatement. In February 2009, the Circuit Court judge denied the Motion to lift the abatement.

Puget Sound Energy, Inc. v. All Jurisdictional Sellers of Energy and/or Capacity at Wholesale Into Electric Energy and/or Capacity Markets in the Pacific Northwest, Including Parties to the Western System Power Pool Agreement, Federal Energy Regulatory Commission, Docket Nos. EL01-10-000, et seq., and Ninth Circuit Court of Appeals, Case No. 03-74139 (collectively, Pacific Northwest Refund proceeding).

In July 2001, the FERC called for a preliminary evidentiary 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. During that period, PGE both sold and purchased electricity in the Pacific Northwest. In June 2003, the FERC issued an order terminating the proceeding and denying the claims for refunds. Parties appealed various aspects of these FERC orders to the U.S. Ninth Circuit Court of Appeals (Ninth Circuit).

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

In October 2011, the FERC issued an Order on Remand establishing an evidentiary hearing to determine whether any seller had engaged in unlawful market activity in the Pacific Northwest spot markets during the December 25, 2000 through June 20, 2001 period by violating specific contracts or tariffs, and, if so, whether a direct connection existed between the alleged unlawful conduct and the rate charged under the applicable contract. The FERC held that the *Mobile-Sierra* public interest standard governs challenges to the bilateral contracts at issue in this proceeding, and the strong presumption under *Mobile-Sierra* that the rates charged under each contract are just and reasonable would have to be specifically overcome before a refund could be ordered. The FERC directed the presiding judge, if necessary, to determine a refund methodology and to calculate refunds, but held that a market-wide remedy was not appropriate, given the bilateral contract nature of the Pacific Northwest spot markets. Certain parties claiming refunds filed requests for rehearing of the Order on Remand, contesting, among other things, the applicable refund period reflected in the Order, the use of the *Mobile-Sierra* standard, any restraints in the Order on the type of evidence that could be introduced in the hearing, and the lack of market-wide remedy. The rehearing requests remain pending.

In December 2012, the FERC issued an order granting an interlocutory appeal of the trial judge's ruling on the scope of the remand proceeding. In this order, the FERC held that its Order on Remand was not intended to alter the general state of the law regarding the *Mobile-Sierra* presumption. The FERC also held that the *Mobile-Sierra* presumption could be overcome either by (i) a showing that a respondent had violated a contract or tariff and that the violation had a direct connection to the rate charged under the applicable contract or (ii) a showing that the contract rate at issue imposed an excessive burden or seriously harmed the public interest.

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. Pursuant to the settlement proceedings, the Company received notice of two claims and reached agreements to settle both claims for an immaterial amount. The FERC approved both settlements during 2012.

In May 2007, the FERC approved a settlement between PGE and certain parties in the California refund case in Docket No. EL00-95, et seq. This resolved the claims between PGE and the California parties named in the settlement as to transactions in the Pacific Northwest during the settlement period, January 1, 2000 through June 20, 2001. The settlement with the California parties did not resolve potential claims from other market participants relating to transactions in the Pacific Northwest.

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

ITEM 4. MINE SAFETY DISCLOSURES.

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

PGE's common stock is traded on the New York Stock Exchange (NYSE) under the ticker symbol "POR". As of February 15, 2013, there were 1,040 holders of record of PGE's common stock and the closing sales price of PGE's common stock on that date was $28.98 per share. The following table sets forth, for the periods indicated, the highest and lowest sales prices of PGE's common stock as reported on the NYSE.

	High	Low	Dividends Declared Per Share
2012			
Fourth Quarter	$ 28.08	$ 24.86	$ 0.270
Third Quarter	27.92	26.57	0.270
Second Quarter	26.94	24.25	0.270
First Quarter	25.62	24.29	0.265
2011			
Fourth Quarter	$ 25.54	$ 22.27	$ 0.265
Third Quarter	26.00	21.29	0.265
Second Quarter	26.05	23.30	0.265
First Quarter	24.00	21.64	0.260

While PGE expects to pay comparable quarterly dividends on its common stock in the future, the declaration of any dividends is at the discretion of the Company's Board of Directors. The amount of any dividend declaration depends upon factors that the Board of Directors deems relevant and may include, but are not limited to, PGE's results of operations and financial condition, future capital expenditures and investments, and applicable regulatory and contractual restrictions.

ITEM 6. SELECTED FINANCIAL DATA.

The following consolidated selected financial data should be read in conjunction with Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations" and Item 8.—"Financial Statements and Supplementary Data."

	Years Ended December 31,				
	2012	2011	2010	2009	2008
	(In millions, except per share amounts)				
Statement of Income Data:					
Revenues, net	$ 1,805	$ 1,813	$ 1,783	$ 1,804	$ 1,745
Gross margin	60%	58%	54%	48%	50%
Income from operations	$ 302	$ 309	$ 267	$ 208	$ 217
Net income	140	147	121	89	87
Net income attributable to Portland General Electric Company	141	147	125	95	87
Earnings per share—basic and diluted	1.87	1.95	1.66	1.31	1.39
Dividends declared per common share	1.075	1.055	1.035	1.010	0.970
Statement of Cash Flows Data:					
Capital expenditures	303	300	450	696	383

	As of December 31,				
	2012	2011	2010	2009	2008
	(Dollars in millions)				
Balance Sheet Data:					
Total assets	$ 5,670	$ 5,733	$ 5,491	$ 5,172	$ 4,889
Total long-term debt	1,636	1,735	1,808	1,744	1,306
Total Portland General Electric Company shareholders' equity	1,728	1,663	1,592	1,542	1,354
Common equity ratio	51.1%	48.6%	46.7%	46.9%	47.3%

ITEM 7. 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 and results of operations, business prospects, future loads, the outcome of litigation and regulatory proceedings, future capital expenditures, market conditions, future events or performance and other matters. Words or phrases such as "anticipates," "believes," "estimates," "expects," "intends," "plans," "predicts," "projects," "will likely result," "will continue," "should," or similar expressions are intended to identify such forward-looking statements.

Forward-looking statements are not guarantees of future performance and involve risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed. PGE's expectations, beliefs and projections are expressed in good faith and are believed by 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 proceedings, audits, investigations and actions, including those of the FERC and OPUC with respect to allowed rates of return, financings, electricity pricing and price structures, acquisition and disposal of facilities and other assets, construction and operation of plant facilities, transmission of electricity, recovery of power costs and capital investments, and current or prospective wholesale and retail competition;
- economic conditions that result in decreased demand for electricity, reduced revenue from sales of excess energy during periods of low wholesale market prices, impaired financial stability of vendors and service providers and elevated levels of uncollectible customer accounts;
- the outcome of legal and regulatory proceedings and issues including, but not limited to, the matters described in Note 18, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data" of this Annual Report on Form 10-K;
- unseasonable or extreme weather and other natural phenomena, which could affect customer demand for power and PGE's ability and cost to procure adequate power and fuel supplies to serve its customers, and could increase the Company's costs to maintain its generating facilities and transmission and distribution systems;
- operational factors affecting PGE's power 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;
- the failure to complete capital projects on schedule and within budget or the abandonment of capital projects, which could result in the Company's inability to recover project costs;
- 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, 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 emissions controls or significant emissions fees or taxes, particularly with respect to coal-fired generation facilities, in order to mitigate carbon dioxide, mercury and other gas emissions;
- changes in wholesale prices for fuels, including natural gas, coal and oil, and the impact of such changes on the Company's power costs, and changes in the availability and price of wholesale power;
- changes in residential, commercial, and industrial customer growth, and in demographic patterns, in PGE's service territory;
- the effectiveness of PGE's risk management policies and procedures and the creditworthiness of customers and counterparties;
- declines in the fair value of equity securities held for the defined benefit pension plans and other benefit plans, which could result in increased funding requirements for such plans;
- changes in, and compliance with, environmental and endangered species laws and policies;
- the effects of climate change, including changes in the environment 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;
- cyber security attacks, data security breaches, or other malicious acts that cause damage to the Company's generation and transmission facilities or information technology systems, or result in the release of confidential customer and proprietary information;
- employee workforce factors, including a significant number of employees approaching retirement, potential strikes, work stoppages, and transitions in senior management;
- political, economic, and financial market conditions;
- natural disasters and other risks, such as 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

Operating Activities—PGE is a vertically integrated electric utility engaged in the generation, transmission, distribution, and retail sale of electricity in the state of Oregon, as well as the wholesale purchase and 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 during the year due to the impacts of seasonal weather conditions on demand for electricity. Changes in retail prices for electricity and in customer usage patterns (which can be affected by the economy) also have an effect on revenues, while the availability and price of power and fuel can affect income from operations. PGE is a winter-peaking utility that typically experiences its highest retail energy demand during the winter heating season, with a slightly lower peak in the summer that generally results from air conditioning demand.

Customers and Demand—The majority of the Company's customers are located within the Portland and Salem, Oregon metropolitan areas. The December 2012 seasonally adjusted unemployment rate for the Portland area was 7.4%, while the state of Oregon was 8.4%, compared with the national average of 7.8%. The state of Oregon forecasts that the average Oregon unemployment rate will remain slightly above the national average at 8.1% for 2013.

Retail energy deliveries, as shown in the table below, decreased 0.8% in 2012 from the 2011 level reflecting the effect of cooler weather during the heating season in 2011 while more normal seasonal weather conditions prevailed during 2012. This weather impact is most evident with decreased deliveries to residential customers, despite the growth in the number of customers served. Energy efficiency and conservation efforts by retail customers continue to influence total deliveries, although the financial effects of such efforts are intended to be mitigated by the decoupling mechanism.

The following table indicates the average number of retail customers and deliveries, by customer class, during the past two years:

	2012		2011		Increase/ (Decrease) in Energy Deliveries
	Average Number of Customers	**Energy Deliveries ***	**Average Number of Customers**	**Energy Deliveries ***	
Residential	723,440	7,505	719,977	7,733	(2.9)%
Commercial	103,766	7,402	102,940	7,419	(0.2)
Industrial	261	4,283	255	4,193	2.1
Total	827,467	19,190	823,172	19,345	(0.8)%

* In thousands of MWh.

Adjusted for the effects of weather, total retail energy deliveries in 2012 increased 0.6% compared to 2011. PGE projects that retail energy deliveries for 2013 will increase in the range of 0.5% to 1.0% from 2012 weather adjusted levels, after allowing for energy efficiency and conservation efforts.

Power Operations—PGE utilizes a combination of its own generating resources and wholesale market transactions to meet the energy needs of its retail customers. Based on numerous factors, including plant availability, customer demand, river flows, wind conditions, and current wholesale prices, the Company continuously makes economic dispatch decisions in an effort to obtain reasonably-priced power for its retail customers. As a result, the amount of power generated and purchased in the wholesale market to meet the Company's retail load requirement can vary from period to period.

Plant availability is impacted by planned maintenance and forced outages, during which the respective plant is unavailable to provide power. PGE's thermal generating plants require varying levels of annual maintenance, which is generally performed during the second quarter of the year. More extensive planned service maintenance was performed in 2011, compared to 2012 and 2010. Availability of the plants PGE operates approximated 94%, 93%, and 95% for the years ended December 31, 2012, 2011, and 2010, respectively, with the availability of Colstrip, which PGE does not operate, approximating 93%, 84%, and 95%, respectively.

During the year ended December 31, 2012, the Company's generating plants provided approximately 50% of its retail load requirement, compared to 48% in 2011 and 64% in 2010. The lower relative volume of power generated to meet the Company's retail load requirement during 2012 and 2011 was primarily due to the economic displacement of thermal generation by energy received from hydro resources and lower-cost purchased power.

Energy received from PGE-owned hydroelectric plants and under contracts from mid-Columbia hydroelectric projects decreased 24% in 2012 compared to 2011, primarily due to the expiration of a contract at the end of 2011 representing approximately 156 MW of capacity. These resources provided approximately 19% of the Company's retail load requirement for 2012, compared with 25% for 2011 and 23% for 2010. Energy received from these sources exceeded projections (or "normal") included in the Company's Annual Power Cost Update Tariff (AUT) by approximately 11% during 2012 and 13% during 2011, compared to falling short of such projections by approximately 8% during 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. Based on recent forecasts of regional hydro conditions in 2013, energy from hydro resources is expected to be below normal for 2013.

Energy expected to be received from wind generating resources is projected annually in the AUT and is based on wind studies completed in connection with the permitting process of the wind farm. Any excess in wind generation from that projected in the AUT generally displaces power from higher cost sources, while any shortfall is generally replaced with power from higher cost sources. Energy received from wind generating resources fell short of that projected in PGE's AUT by 20% in 2012, 13% in 2011 and 27% in 2010.

Pursuant to the Company's 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," which ranges from $15 million below to $30 million above baseline NVPC. To the extent actual NVPC is above or below the deadband, the PCAM provides for 90% of the variance to be collected from or refunded to customers, respectively, subject to a regulated earnings test. The following is a summary of the impacts of the PCAM for 2012, 2011 and 2010.

- For 2012, actual NVPC was $17 million below baseline NVPC, and $2 million above the lower deadband threshold, resulting in a potential refund due to customers. However, based on results of the regulated earnings test, no estimated refund to customers was recorded as of December 31, 2012.
- For 2011, actual NVPC was $34 million below baseline NVPC, which is $19 million above the lower deadband threshold, resulting in a potential refund to customers. As of December 31, 2011, PGE recorded an estimated refund to customers of approximately $10 million, which was reduced from the potential refund based on the application of the regulated earnings test. During 2012, the estimated refund to customers was further reduced to $6 million after the application of an updated regulated earnings test.
- For 2010, actual NVPC was approximately $12 million below baseline NVPC, but within the established deadband range; accordingly, no refund to customers was recorded as of December 31, 2010.

Any estimated collection from customers pursuant to the PCAM is recorded in Purchased power and fuel in the Company's statements of income in the period of accrual, while any refund to customers is recorded in Revenues.

For further information concerning the PCAM see *Power Costs* under "*State of Oregon Regulation*" in the Regulation and Rates section of Item 1.—"Business."

General Rate Case—On February 15, 2013, PGE filed with the OPUC a 2014 General Rate Case, which is based on a 2014 test year. PGE requested a $105 million increase in annual revenues, representing an approximate 6% overall increase in customer prices. The requested increase includes improvements to existing power plants and wind forecasting, new Clackamas River fish-sorting facilities, a disaster-preparedness center, technology investments, employee benefit costs and compliance with new federal regulations. In addition, PGE is proposing a capital structure of 50% debt and 50% equity, a return on equity of 10%, a cost of capital of 7.86%, and an average rate base of approximately $3.1 billion.

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

Capital Requirements and Financing—PGE's capital requirements of $303 million in 2012 primarily related to ongoing capital expenditures for the upgrade, replacement, and expansion of transmission, distribution and generation infrastructure, as well as technology enhancements and expenditures related to hydro licensing. During 2012, cash from operations of $494 million funded the Company's capital requirements and the redemption of $100 million of long-term debt.

Capital expenditures in 2013 are expected to approximate $514 million, which includes $161 million related to the new natural gas-fired capacity resource, Port Westward Unit 2, and $8 million related to the Cascade Crossing transmission project described below. This estimate excludes additional costs, described below, that may be required in connection with the outcome of the Company's RFPs for energy and renewable resources:

Power Resources—In accordance with PGE's IRP and pursuant to the OPUC's competitive bidding guidelines, the Company issued two RFPs during 2012 for additional generation resources - one for capacity and energy (baseload) resources and one for renewable resources.

The RFP for capacity and energy resources is seeking, in addition to capacity and flexible peaking resources, approximately 300 MW to 500 MW of baseload energy resources. PGE has evaluated the energy resource bids received, and has developed a short list of bids for negotiation, with final resource selection expected by mid-2013. The baseload energy resources are expected to be available in the 2014 to 2017 timeframe.

The RFP for renewable resources is seeking approximately 100 MWa of renewable resources, which would be expected to be available to meet PGE's 2015 requirements under Oregon's renewable energy standard. The Company is evaluating the renewable resources bids received, and expects a final short list in early March 2013, with final resource selection by mid-2013.

An independent evaluator selected by the OPUC is helping conduct the RFPs and reviewing bids to ensure an objective and impartial process.

Transmission Capacity—Pursuant to the Company's IRP, PGE has been in the process of developing new transmission capacity from Boardman, Oregon to Salem, Oregon, under a project known as Cascade Crossing Transmission Project, or "Cascade Crossing." This project was originally proposed as a 215-mile, 500 kV transmission project to help meet future electricity demand. As PGE has worked with BPA in the formulation of the project and potential partnerships, the scope of the project has evolved. In January 2013, the Company entered into a Memorandum of Understanding (MOU) with BPA to pursue modifications to PGE's originally proposed project. Under this modified proposal, the transmission line would terminate at a new substation called Pine Grove, near Maupin, Oregon (approximately midway between Boardman and Salem), eliminating construction of approximately 101 miles of the originally proposed transmission line. This modification would avoid most impacts to the Confederated Tribes of Warm Springs Reservation, the

Mt. Hood and Willamette national forests, and private forest and agricultural land in Marion and Linn Counties, and would reduce land acquisition, construction and environmental impacts, as well as resulting mitigation costs.

In addition to construction of the new transmission line, PGE would build the new Pine Grove substation, install series capacitors on existing BPA transmission lines and make other enhancements to the regional grid that would increase transmission capacity. In return, PGE would receive certain transmission capacity rights from BPA, with the details of such rights subject to further negotiation. The MOU also provides for the parties to negotiate an exchange whereby PGE would obtain from BPA ownership of additional transmission capacity in exchange for ownership and/or rights to certain PGE assets. Subject to the outcome of negotiations, the modified proposal would provide PGE a total of up to 2,600 MWs of transmission capacity that could be staged to come on-line in phases as needed,

Construction of the new transmission line from Boardman to the Pine Grove substation could start as early as 2017, with an estimated construction period of at least two years. As the parties continue negotiation of the terms and conditions of the modified proposal, the estimated costs and timeline of the project will be clarified. However, PGE expects the cost of the full project scope, as modified, to be at least $800 million.

For additional information concerning PGE's IRP and the projects discussed above, see "*Future Energy Resource Strategy*" in the Power Supply section of Item 1.—"Business" and "*Capital Requirements*" in the Liquidity and Capital Resources section in this Item 7.

For 2013, PGE expects to fund estimated capital requirements and contractual maturities of $100 million of long-term debt with cash from operations, short-term debt, or long-term financings. Cash from operations is expected to approximate $468 million for 2013. The Company expects that the timing and amount of future issuances of debt and equity securities will depend primarily on the outcome of the Company's RFPs for energy and renewable resources, as well as the timing and scope of Cascade Crossing. For further information, see the Liquidity and Debt and Equity Financings sections of this Item 7.

Legal, Regulatory and Environmental Matters—PGE is a party to certain proceedings, the ultimate outcome of which could 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:

- 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 Refund proceeding; and
- An investigation of environmental matters at Portland Harbor.

For additional information regarding the above and other matters, see Note 18, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

The following discussion highlights certain regulatory items, which have impacted the Company's revenues, results of operations, or cash flows for 2012, or have affected customer prices, as authorized by the OPUC. In some cases, the Company 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:

Boardman Operating Life Adjustment—In PGE's 2011 General Rate Case, the OPUC 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 Boardman over a shortened operating life. 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. The tariff also 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 files annually an estimate of power costs for the following year. In the event a general rate case is filed in any given year, forecasted power costs would be included in such filing. In November 2011, the OPUC issued an order on the 2012 AUT resulting in an estimated decrease in customer prices as a result of expected lower power costs. The new prices became effective January 1, 2012 and were expected to result in a decline of approximately $22 million in annual revenues compared to 2011. Actual net variable power costs for 2012 were $17 million below what was expected in the AUT.

The 2013 AUT filing, which forecast power costs for 2013 to be lower than 2012, was approved by the OPUC and became effective January 1, 2013, with an expected reduction in annual revenues of $36 million.

In July 2012, the Company submitted to the OPUC the results of its PCAM for 2011 based on an updated regulated earnings test, which resulted in a refund to customers of approximately $6 million. In October 2012, the OPUC issued an order approving the refund, with the impact to customer prices effective January 1, 2013. For further information, see "*Power Operations*" in the Operating Activities section of this Overview, above.

Renewable Resource Costs—Pursuant to a renewable adjustment clause (RAC) mechanism, 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 to become effective January 1st of the following year. As part of the RAC, the OPUC has authorized the deferral of eligible costs not yet included in customer prices until the January 1st effective date.

In March 2012, PGE submitted, and the OPUC subsequently approved, a filing for the installation of a small solar facility that requested a nominal credit to customer prices for a one-year period that began January 1, 2013, resulting from the gain on the sale and lease-back transaction directly related to the project.

Decoupling Mechanism—The decoupling mechanism, which is currently authorized through 2013, is intended to provide for recovery of margin lost as a result of a reduction in electricity sales attributable to energy efficiency and conservation efforts by residential and certain commercial customers. The mechanism provides for collection from (or refund to) customers if weather adjusted use per customer is less (or more) than that projected in the Company's most recent general rate case. Collection or refund is expected to occur over one-year periods, which begin June 1 of the following year. For the year ended December 31, 2012, the Company recorded an estimated refund of $1 million, which resulted primarily from slightly higher weather adjusted use per customer than that projected in the 2011 General Rate Case.

Capital deferral—In the 2011 General Rate Case, the OPUC authorized the Company to defer the costs associated with four capital projects that were not completed at the time the 2011 General Rate Case was approved. A regulatory asset of $15 million was recorded in 2012, for potential recovery in customer prices, subject to an earnings test, with an offsetting credit to Depreciation and amortization expense. The Company expects to submit a filing to the OPUC by mid-2013 for recovery of the deferral, with a resulting tariff effective January 1, 2014.

Results of Operations

The following tables provide financial and operational information to be considered in conjunction with management's discussion and analysis of results of operations.

The consolidated statements of income for the years presented (dollars in millions):

	Years Ended December 31,					
	2012		2011		2010	
	Amount	As % of Rev	Amount	As % of Rev	Amount	As % of Rev
Revenues, net	$ 1,805	100%	$ 1,813	100%	$ 1,783	100%
Purchased power and fuel	726	40	760	42	829	46
Gross margin	1,079	60	1,053	58	954	54
Operating expenses:						
Production and distribution	211	12	201	11	174	10
Administrative and other	216	12	218	12	186	11
Depreciation and amortization	248	14	227	13	238	13
Taxes other than income taxes	102	5	98	5	89	5
Total operating expenses	777	43	744	41	687	39
Income from operations	302	17	309	17	267	15
Other income:						
Allowance for equity funds used during construction	6	—	5	—	13	1
Miscellaneous income, net	4	—	1	—	4	—
Other income, net	10	—	6	—	17	1
Interest expense	108	6	110	6	110	6
Income before income taxes	204	11	205	11	174	10
Income taxes	64	3	58	3	53	3
Net income	140	8	147	8	121	7
Less: net loss attributable to noncontrolling interests	(1)	—	—	—	(4)	—
Net income attributable to Portland General Electric Company	$ 141	8%	$ 147	8%	$ 125	7%

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

	Years Ended December 31,								
	2012			2011			2010		
Revenues[1] (dollars in millions):									
Retail:									
Residential	$	860	48%	$	877	48%	$	803	45%
Commercial		633	34		635	35		601	34
Industrial		226	13		226	13		221	12
Subtotal		1,719	95		1,738	96		1,625	91
Other accrued (deferred) revenues, net		4	—		(16)	(1)		39	2
Total retail revenues		1,723	95		1,722	95		1,664	93
Wholesale revenues		49	3		60	3		87	5
Other operating revenues		33	2		31	2		32	2
Total revenues	$	1,805	100%	$	1,813	100%	$	1,783	100%
Energy deliveries[2] (MWh in thousands):									
Retail:									
Residential		7,505	35%		7,733	36%		7,452	35%
Commercial		7,402	35		7,419	35		7,277	34
Industrial		4,283	20		4,193	19		4,004	19
Total retail energy deliveries		19,190	90		19,345	90		18,733	88
Wholesale energy deliveries		2,249	10		2,142	10		2,580	12
Total energy deliveries		21,439	100%		21,487	100%		21,313	100%
Average number of retail customers:									
Residential		723,440	87%		719,977	87%		717,719	88%
Commercial		103,766	13		102,940	13		102,282	12
Industrial		261	—		255	—		265	—
Total		827,467	100%		823,172	100%		820,266	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.

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

	Years Ended December 31,					
	2012		2011		2010	
Sources of energy (MWh in thousands):						
Generation:						
Thermal:						
Coal	3,610	17%	4,125	19%	4,984	23%
Natural gas	2,882	14	2,138	10	4,460	21
Total thermal	6,492	31	6,263	29	9,444	44
Hydro	1,943	9	1,933	9	1,830	9
Wind	1,125	5	1,216	6	833	4
Total generation	9,560	45	9,412	44	12,107	57
Purchased power:						
Term	7,382	35	6,252	29	3,984	19
Hydro	1,728	8	2,897	13	2,417	11
Wind	319	1	269	1	297	1
Spot	2,285	11	2,763	13	2,618	12
Total purchased power	11,714	55	12,181	56	9,316	43
Total system load	21,274	100%	21,593	100%	21,423	100%
Less: wholesale sales	(2,249)		(2,142)		(2,580)	
Retail load requirement	19,025		19,451		18,843	

Net income attributable to Portland General Electric Company for the year ended December 31, 2012 was $141 million, or $1.87 per diluted share, compared to $147 million, or $1.95 per diluted share, for the year ended December 31, 2011. The $6 million, or 4%, decrease in net income was primarily driven by the 3% decrease in retail energy deliveries to residential customers, primarily resulting from warmer weather during the heating season, which was partially offset by a 3% decrease in average variable power cost. Decreased average variable power cost was driven by lower wholesale power and natural gas prices. Actual NVPC was $17 million below the baseline NVPC established in the AUT for 2012, compared to $34 million below the baseline in 2011. In addition, a higher effective income tax rate and increased pension expense contributed to the decrease in net income. Offsetting these decreases, was the deferral of $15 million of costs related to four capital projects during 2012.

Net income attributable to Portland General Electric Company for the year ended December 31, 2011 was $147 million, or $1.95 per diluted share, compared to $125 million, or $1.66 per diluted share, for the year ended December 31, 2010. The $22 million, or 18%, increase in net income was primarily due to the combined effects of a 3% increase in total retail energy deliveries, a 4% increase in customer retail prices, and a 9% decrease in average variable power cost. 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 lower cost hydro and wind resources. As a result of decreased NVPC, actual NVPC was $34 million below baseline NVPC in 2011, compared to $12 million in 2010. Offsetting these increases to net income were higher employee-related costs.

2012 Compared to 2011

Revenues decreased $8 million in 2012 compared with 2011 as a result of the net effect of the items discussed below.

Total retail revenues were comparable with the prior year due primarily to the net effect of the following items:

- An $18 million increase as a result of credits provided to customers in 2011 (offset in Depreciation and amortization), with no comparable refund in 2012. The customer credits were the result of tax credits the Company had accumulated over several years in relation to the Independent Spent Fuel Storage Installation located at the former Trojan site;
- A $14 million increase related to the PCAM, as an estimated refund to customers in the amount of $10 million was recorded in 2011 compared with a $4 million reduction in the estimated PCAM refund for the 2011 year recorded in 2012. No estimated refund or collection was recorded under the PCAM related to the 2012 year. For further discussion of the PCAM, see "Purchased power and fuel expense," below; and
- A $17 million increase resulting from supplemental tariffs and several small regulatory items, which are primarily offset in other line items in the statements of income and thus have no effect on income. The largest contributors amounted to $5 million for the recovery of costs under the solar Feed-In Tariff and $3 million for the recovery of expenses related to the Trojan refund; offset by
- A $34 million decrease related to the volume of retail energy sold and delivered. Residential volumes were down 3%, primarily driven by warmer temperatures during the heating season in 2012. Deliveries to industrial customers were up 2% due largely to increased demand from the high technology sector; and
- A $15 million decrease related to changes in the average retail price, resulting primarily from tariff changes effective January 1, 2012 as authorized by the OPUC including lower anticipated power costs included in the AUT partially offset by a $7 million net annual increase related to the tariff for recovery of Boardman over a shortened operating life. Incremental revenues under the Boardman tariff for the full year 2012 were $14 million compared with $7 million for the last six months of 2011.

Heating degree-days in 2012 were 2% less than the 15-year average provided by the National Weather Service, as measured at Portland International Airport, and decreased 10% compared with 2011, which had 10% more heating degree-days than the 15-year average. The following table indicates the number of actual heating and cooling degree-days for the periods presented, along with the 15-year averages:

	Heating Degree-Days		Cooling Degree-Days	
	2012	2011	2012	2011
1st Quarter	1,967	1,974	—	—
2nd Quarter	709	946	40	16
3rd Quarter	58	51	395	346
4th Quarter	1,435	1,679	1	—
Full Year	4,169	4,650	436	362
15-year Full Year average	4,235	4,219	456	464

On a weather adjusted basis, retail energy deliveries in 2012 increased 0.6% compared to 2011. Deliveries to residential, commercial, and industrial customers increased by 0.4%, 0.2%, and 1.7%, respectively. PGE projects that retail energy deliveries for 2013 will increase in the range of 0.5% to 1.0% from 2012 weather adjusted levels, after allowing for energy efficiency and conservation efforts.

Wholesale revenues result from sales of electricity to utilities and power marketers that are made in the Company's efforts to secure reasonably priced power for its retail customers, manage risk, and administer its current long-term wholesale contracts. Such sales can vary significantly from year to year as a result of economic conditions, power and fuel prices, hydro and wind availability, and customer demand.

In 2012, wholesale revenues decreased $11 million, or 18%, from 2011 levels as a result of the net effect of the following:

- A $14 million decrease related to a 22% decline in the average wholesale price the Company received, driven by lower electricity market prices due to the relatively low price of natural gas and a surplus of hydro generation in the region; partially offset by
- A $3 million increase due to a 5% increase in wholesale energy sales volume.

Purchased power and fuel expense includes the cost of power purchased and fuel used to generate electricity to meet PGE's retail load requirements, as well as the cost of settled electric and natural gas financial contracts. In 2012, Purchased power and fuel expense decreased $34 million, or 4%, from 2011, with $19 million related to a 3% decrease in average variable power cost and $11 million related to a 1% decrease in total system load. The average variable power cost was $34.25 per MWh in 2012 compared to $35.15 per MWh in 2011. Actual NVPC was $17 million below baseline NVPC established in the AUT for 2012, compared with $34 million below baseline NVPC in 2011.

The mix of the decrease in Purchased power and fuel expense largely consisted of:

- A $49 million decrease in the cost of purchased power, consisting of $30 million related to a 6% decrease in average cost and $19 million related to a 4% decrease in purchases. The decrease in average cost was primarily driven by lower wholesale power prices resulting from favorable hydro conditions and low natural gas prices; partially offset by
- A $19 million increase in the cost of generation, primarily due to an increase in the proportion of power provided by the Company's natural gas-fired generating plants, meeting 15% of PGE's retail load requirement in 2012 compared to 11% in 2011. Energy from natural gas-fired generation increased 35% and the average cost of such generation decreased 16% on lower natural gas prices. The average cost of power generated increased 5% in 2012 compared to 2011.

Energy from PGE-owned wind generating resources (Biglow Canyon) decreased 7% from 2011, and represented 6% of the Company's retail load requirement in 2012 and in 2011. The decrease from prior year was due to unfavorable wind conditions, with energy received from Biglow Canyon falling short of projections included in the Company's AUT by approximately 20% in 2012 compared to 13% in 2011.

Hydroelectric energy, from PGE-owned hydroelectric projects and from mid-Columbia projects combined, decreased 24% during 2012 from 2011, which was primarily the result of the expiration of a contract related to a mid-Columbia project that represented approximately 156 MW of capacity. Favorable hydro conditions in both 2012 and 2011 resulted in total hydroelectric energy received for each respective year exceeding that projected in the Company's AUT by approximately 11% for 2012 and 13% for 2011. Based on recent forecasts of regional hydro conditions in 2013, energy from hydro resources is expected to be below normal levels.

The following table indicates the forecast of the April-to-September 2013 runoff (issued February 18, 2013) compared to the actual runoffs for 2012 and 2011 (as a percentage of normal, as measured over the 30-year period from 1971 through 2000):

	Runoff as a Percent of Normal *		
Location	**2013 Forecast**	**2012 Actual**	**2011 Actual**
Columbia River at The Dalles, Oregon	89%	126%	135%
Mid-Columbia River at Grand Coulee, Washington	90	129	123
Clackamas River at Estacada, Oregon	98	133	135
Deschutes River at Moody, Oregon	92	118	120

* 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.

Gross margin, which represents the difference between Revenues 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.

As a percent of Revenues, Gross margin was 60% in 2012 compared to 58% in 2011. The increase in Gross margin was largely due to certain regulatory items that reduced gross margin in 2011. During 2011, PGE provided customers certain tax credits in the amount of $18 million and recorded an estimated refund to customers of $10 million related to the PCAM, both of these regulatory items reduced gross margin for 2011.

Production and distribution expense increased $10 million, or 5%, in 2012 compared to 2011, primarily due to the following:

- A $4 million increase due to higher maintenance costs of the Company's generating plants and distribution system;
- A $3 million increase due to an insurance recovery related to the Selective Water Withdrawal project recorded in 2011; and
- A $3 million increase due to higher delivery system labor costs.

Administrative and other expense decreased $2 million, or 1%, in 2012 compared to 2011, primarily due to the net effect of the following:

- A $6 million decrease due to expenses related to information technology upgrades in 2011;
- A $3 million decrease related to higher write-offs of uncollectible customer accounts in 2011;
- A $2 million decrease in compensation expense primarily due to lower incentive compensation in 2012; partially offset by
- A $7 million increase in employee pension expenses resulting from a lower discount rate and lower return on pension trust assets; and
- A $3 million increase due to the amortization of deferred expenses related to the Trojan refund (offset in Revenues).

Depreciation and amortization expense increased $21 million, or 9%, in 2012 compared to 2011, due largely to the net effect of the following:

- An $18 million increase related to the amortization of customer refunds for the ISFSI tax credits in 2011 (offset in Revenues);
- A $13 million increase in depreciation expense related to a shorter operating life for the Boardman plant (effective July 2011 and offset in Revenues), and other capital additions including emissions control retrofits at the Boardman plant;
- A $5 million increase in amortization related to the Solar Feed-In Tariff (offset in Revenues); partially offset by
- A $15 million decrease related to the 2012 deferral of costs related to four capital projects as approved in the 2011 General Rate Case.

Taxes other than income taxes increased $4 million, or 4%, in 2012 compared to 2011, primarily due to higher property taxes resulting from increased property values and tax rates. Also contributing to the increase were higher franchise fees.

Other income, net was $10 million in 2012 compared to $6 million in 2011. The increase is primarily due to higher income from the non-qualified benefit plan trust.

Interest expense decreased $2 million, or 2% in 2012, as compared to 2011, primarily due to lower interest resulting from a lower average outstanding balance of long-term debt.

Income taxes increased $6 million, or 10%, in 2012, compared to 2011, with effective tax rates of 31.4% and 28.3% for 2012 and 2011, respectively. The increase in the effective tax rate is primarily due to the change in apportionment of state income taxes, which resulted in an increase to deferred taxes. The change in apportionment was caused by lower wholesale sales in Washington, which has no corporate income tax, resulting in more taxable income being apportioned to Oregon.

2011 Compared to 2010

Revenues increased $30 million, or 2%, in 2011 compared to 2010 as a result of the net effect of the items discussed below.

Total retail revenues increased $58 million, or 3%, due primarily to the following items:

- A $62 million increase related to the volume of retail energy sold. Residential volumes were up 4%, primarily driven by cooler temperatures in the heating seasons. In addition, commercial and industrial deliveries were up 3% due largely to increased demand from the paper sector;
- A $61 million increase related to changes in average retail price that resulted primarily from the 3.9% overall increase effective January 1, 2011 authorized by the OPUC in the Company's 2011 General Rate Case and an increase effective July 1, 2011 related to the recovery of Boardman over a shortened operating life; partially offset by
- An $18 million decrease as a result of the ISFSI tax credits refund recorded in 2011 (offset in Depreciation and amortization), with no comparable refund in 2010;
- An $18 million decrease related to the deferral of revenue requirements for Biglow Canyon in 2010, which was included in Other accrued revenues. In 2011, the recovery of Biglow Canyon is included in the average retail price discussed above as a result of the 2011 General Rate Case;
- A $10 million decrease related to the decoupling mechanism, which is included in Other accrued revenues. In 2011, a $2 million refund to customers was recorded, which resulted primarily from slightly higher weather adjusted use per customer than that approved in the 2011 General Rate Case. Among other things,

the 2011 General Rate Case reset the baseline used for the decoupling mechanism. An $8 million collection from customers was recorded in 2010, resulting from lower weather adjusted use per customer than that approved in the 2009 General Rate Case;

- A $10 million decrease related to an estimated refund to customers, pursuant to the PCAM, recorded in 2011 and included in Other accrued revenues, with no amount recorded in 2010. For further discussion of the PCAM, see "Purchased power and fuel expense," below;
- A $7 million decrease related to the regulatory treatment of income taxes (Senate Bill 408) primarily due to an adjustment recorded in 2010 that pertained to the 2009 liability, which was included in Other accrued revenues. Senate Bill 408 was repealed in 2011 and no longer applies to tax years after 2009; and
- A $5 million decrease due to the 2010 reversal of a deferral for customer refunds pursuant to an OPUC order related to the 2005 Oregon Corporate Tax Kicker, which was included in Other accrued revenues.

Heating degree-days in 2011 were 10% greater than the 15-year average and increased 11% compared to 2010, while cooling degree-days increased 15% from 2010. 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 and illustrates that weather effects increased the demand for electricity in 2011 over 2010:

	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
4th Quarter	1,679	1,580	—	—
Full Year	4,650	4,187	362	314
15-year Full Year average	4,219	4,192	464	473

On a weather adjusted basis, retail energy deliveries in 2011 increased 1.4% compared to 2010, with 1% attributable to the paper production sector. Deliveries to residential, commercial, and industrial customers increased by 0.2%, 0.4%, and 5.3%, respectively.

Wholesale revenues in 2011 decreased $27 million, or 31%, from 2010 as a result of the following:

- A $14 million decrease due to a 17% decline in wholesale energy sales volume; and
- A $13 million decrease related to a 17% decline in the average wholesale price the Company received, driven by lower electricity market prices due to abundant hydro in the region.

Purchased power and fuel expense decreased $69 million, or 8%, in 2011 from 2010, with $75 million related to a 9% decrease in average variable power cost, partially offset by $7 million related to a 1% increase in total system load. The average variable power cost was $35.15 per MWh in 2011 and $38.68 per MWh in 2010.

The mix of the decrease in Purchased power and fuel expense consisted of:

- A $71 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 2011, a significant amount of thermal generation was economically displaced by lower cost purchased power and increased energy received from lower cost hydro and wind generating resources, relative to 2010. The average cost of power generated increased 1% in 2011 compared to 2010; and
- A $2 million increase in the cost of purchased power, consisting of $151 million related to a 31% increase in purchases, substantially offset by $149 million related to a 23% decrease in average cost. The decrease in

average cost was primarily driven by lower wholesale power prices resulting from favorable hydro conditions.

Energy received from PGE-owned wind generating resources (Biglow Canyon) increased 46% from 2010, and represented 6% of the Company's retail load requirement in 2011 compared to 4% in 2010. These increases were due to the August 2010 completion of the third and final phase of Biglow Canyon and favorable wind conditions in 2011 relative to 2010. Energy received from wind generating resources fell short of projections included in the Company's AUT by approximately 13% in 2011 and 27% in 2010.

For 2011, energy received from PGE-owned hydroelectric plants and under contracts from mid-Columbia projects exceeded that projected in the Company's 2011 AUT by 13% and 14% compared to 2010. For 2010, energy received from these hydroelectric resources fell short of projections included in the Company's 2010 AUT by approximately 8%.

Actual NVPC was $34 million below baseline NVPC in 2011, compared with $12 million below baseline NVPC in 2010.

Gross margin was 58% in 2011 compared to 54% in 2010. The increase in Gross margin was driven by the 9% decrease in average variable power cost and increases of 3% in retail energy deliveries and 4% 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 $27 million, or 16%, in 2011 compared to 2010, primarily due to the following:

- A $10 million increase due to increased 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;
- A $9 million increase to distribution system expenses primarily related to increased information technology costs and tree trimming activities; and
- An $8 million increase related to higher labor and employee benefit costs.

Administrative and other expense increased $32 million, or 17%, in 2011 compared to 2010, primarily due to the following:

- A $13 million increase primarily due to higher pension and employee benefit expenses, and increased incentive compensation related to an improvement in corporate financial and operating performance for 2011;
- A $5 million increase related to higher information technology costs;
- A $4 million increase in fees related to various legal and environmental proceedings;
- A $3 million increase in the provision and write-off of certain uncollectible customer accounts; and
- A $2 million increase related to higher OPUC regulatory fees resulting from higher prices in 2011 (fully offset in Retail revenues).

Depreciation and amortization expense decreased $11 million, or 5%, in 2011 compared to 2010, due largely to the net effect of the following:

- An $18 million decrease related to the amortization of customers refunds for the ISFSI tax credits (offset in Revenues);
- A $12 million decrease related to increases in estimated useful lives and reductions to estimated removal costs of certain long-lived assets due to an updated depreciation study;

- A $4 million decrease related to the impairment loss recognized in 2010 on photovoltaic solar power facilities, the majority of which was allocated to noncontrolling interests through the Net loss attributable to the noncontrolling interest. For additional information, see Note 16, Variable Interest Entities, in the Notes to Consolidated Financial Statements included in Item 8.—"Financial Statements and Supplementary Data"; partially offset by
- A $21 million increase in depreciation related to the August 2010 completion of the third and final phase of Biglow Canyon wind farm, Boardman shortened operating life, the Smart Meter project, and other capital additions in late 2010 and in 2011; and
- A $2 million increase in amortization related to hydroelectric licenses.

Taxes other than income taxes increased $9 million, or 10%, in 2011 compared to 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 was $6 million in 2011 compared to $17 million in 2010. The decrease was primarily due to the following:

- An $8 million decrease in the allowance for equity funds used during construction, as a result of lower construction work in progress balances during 2011, related primarily to the August 2010 completion of third and final phase of Biglow Canyon wind farm; and
- A $5 million decrease in income from non-qualified benefit plan trust assets, resulting from a minimal loss in the fair value of the plan assets in 2011 compared to a $5 million gain in 2010.

Interest expense in 2011 was comparable to 2010, as a $6 million decrease in the allowance for funds used during construction, primarily driven by the August 2010 completion of the third and final phase of Biglow Canyon wind farm, was offset by lower interest on long-term debt and certain regulatory liabilities.

Income taxes increased $5 million, or 9%, in 2011 compared to 2010, primarily due to higher income before taxes in 2011, partially offset by increased federal wind production tax credits (PTCs) in that year. The effective tax rates (28.3% in 2011 and 30.3% in 2010) differ from the federal statutory rate primarily due to benefits from PTCs and state tax credits. An increase in PTCs, related to increased production from the completed Biglow Canyon wind farm, was partially offset by an increase in the state income tax rate and a reduction in state tax credits.

Net loss attributable to noncontrolling interests represents the noncontrolling interests' portion of the net loss of PGE's less-than-wholly-owned subsidiaries, the majority of which in 2010 consists of impairment losses recognized on the photovoltaic solar power facilities, discussed previously in Depreciation and amortization.

Liquidity and Capital Resources

Discussions, forward-looking statements and projections in this section, and similar statements in other parts of the Form 10-K, are subject to PGE's assumptions regarding the availability and cost of capital. See "Current capital and credit market conditions could adversely affect the Company's access to capital, cost of capital, and ability to execute its strategic plan as currently scheduled." in Item 1A.—"Risk Factors."

Capital Requirements

The following table indicates actual capital expenditures for 2012 and future debt maturities and projected cash requirements for 2013 through 2017 (in millions, excluding AFDC):

	Years Ending December 31,					
	2012	2013	2014	2015	2016	2017
Ongoing capital expenditures	$ 263	$ 322	$ 285	$ 253	$ 262	$ 245
Port Westward Unit 2	1	161	107	33	—	—
Hydro licensing and construction	22	23	28	28	1	—
Cascade Crossing	24	8	—	—	—	—
Total capital expenditures	$ 310 (1)	$ 514	$ 420	$ 314	$ 263	$ 245
Long-term debt maturities	$ 100	$ 100	$ —	$ 70	$ 67	$ 58

(1) Amounts shown include removal costs, which are included in other net operating activities in the consolidated statements of cash flows.

Ongoing capital expenditures—Consists of upgrades to and replacement of transmission, distribution, and generation infrastructure as well as new customer connections. Included in the amounts presented is approximately $13 million in expected capital expenditures for emissions controls at Boardman in 2013.

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, amounted to $5 million in 2012. Included in Ongoing capital expenditures in the table above are approximately $3 million of Preliminary engineering the Company expects that it will spend in 2013.

Port Westward Unit 2—In January 2013, PGE's Port Westward Unit 2 (PW2) flexible generating resource was selected as the successful bid for the capacity resource in the Company's RFP for energy and capacity resources. PW2 is a 220 MW natural gas-fired plant that will be located near PGE's Port Westward and Beaver natural gas-fired plants near Clatskanie, Oregon. Total cost of PW2 is estimated between $300 million and $310 million, excluding AFDC, and the facility is expected to be online in 2015.

Hydro licensing and construction—PGE's hydroelectric projects are operated pursuant to FERC licenses issued under the Federal Power Act. The licenses for the hydroelectric projects expire as follows: Clackamas River, 2055; Willamette River, 2035; and Deschutes River, 2055. Capital spending requirements reflected in the table above relate primarily to modifications to the Company's various hydro facilities to enhance fish passage and survival, as required by conditions contained in the operating licenses.

Integrated resource plan—Pursuant to the energy and capacity RFP issued in 2012 in accordance with the Company's IRP, PGE is in negotiations with the top bidder from the short list of winning projects for energy resources, which include power purchase agreements and PGE-ownership options. The successful bidder for the energy resources component of this RFP is expected to be selected by mid-2013. A second RFP for approximately 100 MWa of renewable resources was issued in 2012, for which the Company expects the successful bidders to be selected by mid-2013. Selection of, and negotiations with, the successful bidders for the energy and renewable resources will clarify timing and total cost of these projects.

In addition, the Company continues to work with stakeholders in the development of, and the formation of potential partnerships for Cascade Crossing, to provide additional transmission capacity from northeastern Oregon to PGE's service territory. As of December 31, 2012, approximately $46 million is included in construction work-in-progress related to this project. As the parties continue negotiations of the terms and conditions of the modified proposal, the estimated costs and timeline of the project will be clarified.

Due to the uncertainty of these IRP projects, the Capital Requirements table presented at the beginning of this section does not include estimates for any amounts related to these projects beyond 2013.

For further information on the Company's IRP, including the projects subject to the RFP process or Cascade Crossing, see "*Future Energy Resource Strategy*" in the Power Supply section and the Transmission and Distribution section contained in Item 1.—"Business" and "Capital Requirements and Financing" in the Overview section of this Item 7.

Liquidity

PGE's access to short-term debt markets, including revolving credit from banks, helps provide necessary liquidity to support the Company's 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):

	Years Ended December 31,		
	2012	2011	2010
Cash and cash equivalents, beginning of year	$ 6	$ 4	$ 31
Net cash provided by (used in):			
Operating activities	494	453	391
Investing activities	(294)	(299)	(430)
Financing activities	(194)	(152)	12
Net change in cash and cash equivalents	6	2	(27)
Cash and cash equivalents, end of year	$ 12	$ 6	$ 4

2012 Compared to 2011

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, including depreciation and amortization, included in net income during a given period. The $41 million increase in cash provided by operating activities in 2012 compared to 2011 was largely due to the impact of a combined contribution of $42 million to the pension plan and the voluntary employees' beneficiary association trusts (VEBAs) in 2011 and a decrease in margin deposit requirements, partially offset by a decrease in net income after the consideration of non-cash items. The VEBAs fund the benefits of the Company's non-contributory postretirement health and life insurance plans.

Cash provided by operations includes the recovery in customer prices non-cash charges for depreciation and amortization. The Company estimates that such charges will approximate $244 million in 2013. Combined with all other sources, cash provided by operations is estimated to be approximately $468 million in 2013. This estimate anticipates no change in margin deposits held by brokers as of December 31, 2012, which is based on both the timing of contract settlements and projected energy prices. The remaining $224 million in estimated cash flows from operations in 2013 is expected from normal operating activities.

Cash Flows from Investing Activities—Cash flows used in investing activities consist primarily of capital expenditures related to new construction and improvements to PGE's distribution, transmission, and generation facilities. The $5 million decrease in net cash used in investing activities in 2012 compared to 2011 was primarily due to proceeds received in the amount of $10 million for the sale of a solar power facility during the first quarter of 2012, partially offset by a 1% increase in capital expenditures.

The Company plans approximately $514 million of capital expenditures in 2013 related to upgrades to and replacement of transmission, distribution and generation infrastructure, including $161 million related to the construction of Port Westward Unit 2, a new natural gas-fired generating resource. PGE plans to fund the 2013 capital expenditures with the cash expected to be generated from operations during 2013, as discussed above, as well as with short-term debt and long-term financings. For additional information, see "*Capital Requirements*" in the Liquidity and Capital Resources section of this Item 7.

Cash Flows from Financing Activities—Financing activities provide supplemental cash for both day-to-day operations and capital requirements as needed. During 2012, net cash used in financing activities consisted of the repayment of long-term debt of $100 million, the payment of dividends of $81 million and net maturities of commercial paper of $13 million. During 2011, net cash used in financing activities primarily consisted of the payment of dividends of $79 million and the repayment of long-term debt of $80 million, including the premium paid, partially offset by net issuances of commercial paper of $11 million.

2011 Compared to 2010

Cash Flows from Operating Activities—The $62 million increase in cash provided by operating activities in 2011 compared to 2010 was largely due to an increase in net income after the consideration of non-cash items, as well as a decrease in margin deposit requirements pursuant to certain power and natural gas purchase and sale agreements. Such increases were partially offset by a $44 million decrease in the income tax refunds received in 2011 compared to 2010 and a $16 million contribution to the VEBAs in 2011. The VEBAs fund the benefits of the Company's noncontributory postretirement health and life insurance plans.

Cash Flows from Investing Activities—The $131 million decrease in cash used in investing activities in 2011 compared to 2010 was due to lower capital expenditures of $150 million due to decreased construction costs related to the completion of Biglow Canyon Phase III in August 2010, as well as the effect of a $19 million distribution from the Nuclear decommissioning trust to PGE in 2010.

Cash Flows from Financing Activities—During 2011, net cash used in financing activities primarily consisted of the payment of dividends of $79 million and the repayment of of long-term debt of $80 million, including the premium paid, partially offset by net issuances of commercial paper of $11 million. During 2010, net cash provided by financing activities consisted primarily of proceeds received from the issuance or remarketing of long-term debt of $249 million, net issuances of commercial paper of $19 million and noncontrolling interests' capital contributions of $10 million, partially offset by the repayment of long-term debt of $186 million and the payment of dividends of $78 million.

Dividends on Common Stock

The following table indicates common stock dividends declared in 2012:

Declaration Date	Record Date	Payment Date	Declared Per Common Share
February 22, 2012	March 26, 2012	April 16, 2012	$ 0.265
May 23, 2012	June 25, 2012	July 16, 2012	0.270
August 2, 2012	September 25, 2012	October 15, 2012	0.270
November 7, 2012	December 26, 2012	January 15, 2013	0.270

While the Company expects to pay comparable quarterly dividends on its common stock in the future, 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 and may include, but are not limited to, PGE's results of operations and financial condition, future capital expenditures and investments, and applicable regulatory and contractual restrictions.

On February 20, 2013, the Board of Directors declared a dividend of $0.27 per share of common stock to stockholders of record on March 25, 2013, payable on or before April 15, 2013.

Credit Ratings and Debt Covenants

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

	Moody's	S&P
First Mortgage Bonds	A3	A-
Senior unsecured debt	Baa2	BBB
Commercial paper	Prime-2	A-2
Outlook	Positive	Stable

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

As of December 31, 2012, PGE had posted approximately $91 million of collateral with these counterparties, consisting of $46 million in cash and $45 million in letters of credit, $18 million of which is related to master netting agreements. Based on the Company's energy portfolio, estimates of energy market prices, and the level of collateral outstanding as of December 31, 2012, the approximate amount of additional collateral that could be requested upon a single agency downgrade to below investment grade is approximately $83 million and decreases to approximately $27 million by December 31, 2013. The amount of additional collateral that could be requested upon a dual agency downgrade to below investment grade is approximately $253 million and decreases to approximately $92 million by December 31, 2013.

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

The issuance of First Mortgage Bonds requires that PGE meet earnings coverage and security provisions set forth in the Indenture of Mortgage and Deed of Trust securing the bonds. PGE estimates that on December 31, 2012, under the most restrictive issuance test in the Indenture of Mortgage and Deed of Trust, the Company could have issued up to approximately $703 million of additional First Mortgage Bonds. Any issuances of First Mortgage Bonds would be subject to market conditions and amounts could be further limited by regulatory authorizations or by covenants and tests contained in other financing agreements. PGE also has the ability to release property from the lien of the Indenture of Mortgage and Deed of Trust under certain circumstances, including bond credits, deposits of cash, or certain sales, exchanges or other dispositions of property.

PGE's credit facilities contain customary covenants and credit provisions, including a requirement that limits consolidated indebtedness, as defined in the credit agreements, to 65% of total capitalization (debt ratio). As of December 31, 2012, the Company's debt ratio, as calculated under the credit agreements, was 48.9%.

Debt and Equity Financings

PGE's ability to secure sufficient long-term capital at a reasonable cost is determined by its financial performance and outlook, capital expenditure requirements, alternatives available to investors, and other factors. The Company's ability to obtain and renew such financing depends on its credit ratings, as well as on credit markets, both generally and for electric utilities in particular. Management believes that the availability of credit facilities, the expected ability to issue long-term debt and equity securities, and cash expected to be generated from operations provide sufficient liquidity to meet the Company's anticipated capital and operating requirements. However, the Company's ability to issue long-term debt and equity could be adversely affected by changes in capital market conditions. For 2013, PGE expects to fund estimated capital requirements and contractual maturities of $100 million of long-term debt with cash from operations, short-term debt, or long-term financings. The Company expects that the timing and amount of future issuances of debt and equity securities in the next 5 years will depend primarily on the outcome of the Company's RFPs for energy and renewable resources under its IRP, as well as the timing and scope of Cascade Crossing.

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

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

These credit facilities supplement operating cash flows and provide a primary source of liquidity. Pursuant to the terms of the agreements, the credit facilities may be used for general corporate purposes, as a backup for commercial paper borrowings, and the issuance of standby letters of credit. As of December 31, 2012, PGE had no borrowings outstanding under the credit facilities, with $17 million of commercial paper outstanding and $67 million of letters of credit issued. As of December 31, 2012, the aggregate unused available credit under the credit facilities was $616 million.

Long-term Debt. During 2012, $100 million of First Mortgage Bonds matured and were redeemed. As of December 31, 2012, total long-term debt outstanding was $1,636 million, with $100 million scheduled to mature in 2013, consisting of $50 million due on each of April 1 and August 1. PGE owns $21 million of its Pollution Control Revenue Bonds, which may be remarketed at a later date, at the Company's option, through 2033.

Capital Structure. PGE's financial objectives include the balancing of debt and equity to maintain a low weighted average cost of capital while retaining sufficient flexibility to meet the Company's financial obligations. The Company attempts to maintain a common equity ratio (common equity to total consolidated capitalization, including current debt maturities) of approximately 50%. Achievement of this objective while sustaining sufficient cash flow is necessary to maintain acceptable credit ratings and allow access to long-term capital at attractive interest rates. PGE's common equity ratios were 51.1% and 48.6% as of December 31, 2012 and 2011, respectively.

Contractual Obligations and Commercial Commitments

The following indicates PGE's contractual obligations as of December 31, 2012 (in millions):

	2013	2014	2015	2016	2017	There-after	Total
Long-term debt	$ 100	$ —	$ 70	$ 67	$ 58	$1,341	$1,636
Interest on long-term debt (1)	92	89	87	83	81	1,025	1,457
Capital and other purchase commitments	81	10	11	9	2	72	185
Purchased power and fuel:							
Electricity purchases	154	83	82	64	36	440	859
Capacity contracts	21	21	20	19	—	—	81
Public Utility Districts	8	8	8	7	5	25	61
Natural gas	55	26	21	12	10	6	130
Coal and transportation	22	9	—	—	—	—	31
Pension plan contributions	—	15	32	44	44	64	199
Operating leases	9	9	9	10	11	186	234
Total	$ 542	$ 270	$ 340	$ 315	$ 247	$3,159	$4,873

(1) Future interest on long-term debt is calculated based on the assumption that all debt remains outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect as of December 31, 2012.

Other Financial Obligations

PGE has entered into long-term power purchase contracts with certain public utility districts in the state of Washington under which it has acquired a percentage of the output (Allocation) of three hydroelectric projects (the Priest Rapids, Wanapum and Wells hydroelectric projects). The Company is required to pay its proportionate share of the operating and debt service costs of the projects whether or not they are operable. The contracts further provide that, should any other purchaser of output default on payments as a result of bankruptcy or insolvency, PGE would be allocated a pro rata share of both the output and the operating and debt service costs of the defaulting purchaser. For the Wells project, PGE would be allocated up to a cumulative maximum of 25% of the defaulting purchaser's percentage Allocation. For the Priest Rapids and Wanapum projects, PGE would be allocated up to a cumulative maximum that would not adversely affect the tax exempt status of any outstanding debt.

Off-Balance Sheet Arrangements

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

Critical Accounting Policies

The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires that management apply accounting policies and make estimates and assumptions that affect amounts reported in the statements. The following accounting policies represent those that management believes are particularly important to the consolidated financial statements and that require the use of estimates, assumptions, and judgments to determine matters that are inherently uncertain.

Regulatory Accounting

As a rate-regulated enterprise, PGE is required to comply with certain regulatory accounting requirements, which include the recognition of regulatory assets and liabilities on the Company's consolidated balance sheets.

Regulatory assets represent probable future revenue associated with certain incurred costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited or refunded to customers through the ratemaking process. Regulatory accounting is appropriate as long as prices are established or subject to approval by independent third-party regulators; prices are designed to recover the specific enterprise's cost of service; and in view of demand for service, it is reasonable to assume that prices set at levels that will recover costs can be charged to and collected from customers. Amortization of regulatory assets and liabilities is reflected in the statement of income over the period in which they are included in customer prices.

If future recovery of regulatory assets ceases to be probable, PGE would be required to write them off. Further, if PGE determines that all or a portion of its utility operations no longer meet the criteria for continued application of regulatory accounting, the Company would be required to write off those regulatory assets and liabilities related to operations that no longer meet requirements for regulatory accounting. Discontinued application of regulatory accounting would have a material impact on the Company's results of operations and financial position.

Asset Retirement Obligations

PGE recognizes asset retirement obligations (AROs) for legal obligations related to dismantlement and restoration costs associated with the future retirement of tangible long-lived assets. Upon initial recognition of AROs that are measurable, the probability-weighted future cash flows for the associated retirement costs, discounted using a credit-adjusted risk-free rate, are recognized as both a liability and as an increase in the capitalized carrying amount of the related long-lived assets. Due to the long lead time involved, a market-risk premium cannot be determined for inclusion in future cash flows. In estimating the liability, management must utilize significant judgment and assumptions in determining whether a legal obligation exists to remove assets. Other estimates may be related to lease provisions, ownership agreements, licensing issues, cost estimates, inflation, and certain legal requirements. Changes that may arise over time with regard to these assumptions and determinations can change future amounts recorded for AROs.

Capitalized asset retirement costs related to electric utility plant are depreciated over the estimated life of the related asset and included in Depreciation and amortization expense in the consolidated statements of income. Accretion of the ARO liability is classified as an operating expense in the consolidated statements of income. Accumulated asset retirement removal costs that do not qualify as AROs have been reclassified from accumulated depreciation to regulatory liabilities in the consolidated balance sheets.

Revenue Recognition

Retail customers are billed monthly for electricity use based on meter readings taken throughout the month. At the end of each month, PGE estimates the revenue earned from the last meter read date through the last day of the month, which has not yet been billed to customers. Such amount, which is classified as Unbilled revenues in the Company's consolidated balance sheets, is calculated based on each month's actual net retail system load, the number of days from the last meter read date through the last day of the month, and current customer prices.

Contingencies

PGE has various unresolved legal and regulatory matters about which there is inherent uncertainty, with the ultimate outcome contingent upon several factors. Such contingencies are evaluated using the best information available. A loss contingency is accrued, and disclosed if material, when it is probable that an asset has been impaired or a liability incurred and the amount of the loss can be reasonably estimated. If a range of probable loss is established, the minimum amount in the range is accrued, unless some other amount within the range appears to be a better estimate. If the probable loss cannot be reasonably estimated, no accrual is recorded, but the loss contingency is disclosed to the effect that it cannot be reasonably estimated. Material loss contingencies are disclosed when it is reasonably possible that an asset has been impaired or a liability incurred. Established accruals reflect management's assessment of inherent risks, credit worthiness, and complexities involved in the process. There can be no assurance as to the ultimate outcome of any particular contingency.

Price Risk Management

PGE engages in price risk management activities to manage exposure to commodity and foreign currency market fluctuations and to manage volatility in net power costs for its retail customers. The Company utilizes derivative instruments, which may include forward, futures, swap, and option contracts for electricity, natural gas, oil, and foreign currency. These derivative instruments are recorded at fair value, or "marked-to-market," in PGE's consolidated financial statements.

Fair value adjustments consist of reevaluating the fair value of derivative contracts at the end of each reporting period for the remaining term of the contract and recording any change in fair value in Net income for the period. Fair value is the present value of the difference between the contracted price and the forward market price multiplied by the total quantity of the contract. For option contracts, a theoretical value is calculated using Black-Scholes models that utilize price volatility, price correlation, time to expiration, interest rate and forward commodity price curves. The fair value of these options is the difference between the premium paid or received and the theoretical value at the fair value measurement date.

Determining the fair value of these financial instruments requires the use of prices at which a buyer or seller could currently contract to purchase or sell a commodity at a future date (termed "forward prices"). Forward price "curves" are used to determine the current fair market value of a commodity to be delivered in the future. PGE's forward price curves are created by utilizing actively quoted market indicators received from electronic and telephone brokers, industry publications, and other sources. Forward price curves can change with market conditions and can be materially affected by unpredictable factors such as weather and the economy. PGE's forward price curves are validated using broker quotes and market data from a regulated exchange and differences for any single location, delivery date and commodity are less than 5%.

Pension Plan

Primary assumptions used in the actuarial valuation of the plan include the discount rate, the expected return on plan assets, mortality rates, and wage escalation. These assumptions are evaluated by PGE, reviewed annually with the plan actuaries and trust investment consultants, and updated in light of market changes, trends, and future expectations. Significant differences between assumptions and actual experience can have a material impact on the valuation of the pension benefit plan obligation and net periodic pension cost.

PGE's pension discount rate is determined based on a portfolio of high-quality bonds that match the duration of the plan cash flows. The expected rate of return on plan assets is based on projected long-term return on assets in the plan investment portfolio. PGE capitalizes a portion of pension expense based on the proportion of labor costs capitalized.

Changes in actuarial assumptions can also have a material effect on net periodic pension expense. A 0.25% reduction in the expected long-term rate of return on plan assets, or reduction in the discount rate, would have the effect of increasing the 2012 net periodic pension expense by approximately $2 million.

Discount rates applied to the pension liability have continued to decline due to general macroeconomic and credit market conditions. The Federal Reserve Board's continued low interest rate policy and the general preference in the financial markets for the safety of high-quality bonds has continued to drive the rates on high-quality bonds down throughout 2012, which lowers the discount rate used to measure the pension liability.

Fair Value Measurements

In accordance with accounting and reporting requirements, PGE applies fair value measurements to its financial assets and liabilities. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The Company's financial assets and liabilities consist of derivative instruments, certain assets held by the Nuclear decommissioning, Pension plan and Non-qualified benefit plan trusts, and long-term debt. In valuing these items, the Company uses inputs and assumptions that market participants would use to determine their fair value, utilizing valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The determination of fair value can require subjective and complex judgment and the Company's assessment of the inputs and the significance of a particular input to fair value measurement may affect the valuation of the instruments and their placement within the fair value hierarchy reported in its financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

PGE is exposed to various forms of market risk, consisting primarily of fluctuations in commodity prices, foreign currency exchange rates, and interest rates, as well as credit risk. Any variations in the Company's market risk or credit risk may affect its future financial position, results of operations or cash flows, as discussed below.

Risk Management Committee

PGE has a Risk Management Committee (RMC) which is responsible for providing oversight of the adequacy and effectiveness of corporate policies, guidelines, and procedures for market and credit risk management related to the Company's energy portfolio management activities. The RMC consists of officers and Company representatives with responsibility for risk management, finance and accounting, legal, rates and regulatory affairs, power operations, and generation operations. The RMC reviews and approves adoption of policies and procedures, and monitors compliance with policies, procedures, and limits on a regular basis through reports and meetings. The RMC also reviews and recommends risk limits that are subject to approval by PGE's Board of Directors.

Commodity Price Risk

PGE is exposed to commodity price risk as its primary business is to provide electricity to its retail customers. The Company engages in price risk management activities to manage exposure to volatility in net power costs for its retail customers. The Company uses power purchase contracts to supplement its thermal, hydroelectric, and wind generation and to respond to fluctuations in the demand for electricity and variability in generating plant operations. The Company also enters into contracts for the purchase of fuel for the Company's natural gas- and coal-fired generating plants. These contracts for the purchase of power and fuel expose the Company to market risk. The Company uses instruments such as forward contracts, which may involve physical delivery of an energy commodity; financial swap and futures agreements, which may require payments to, or receipt of payments from, counterparties based on the differential between a fixed and variable price for the commodity; and option contracts to mitigate risk that arises from market fluctuations of commodity prices. PGE does not engage in trading activities for non-retail purposes.

The following table presents energy commodity derivative fair values as a net liability as of December 31, 2012 that are expected to settle in each respective year (in millions):

	2013	2014	2015	Total
Commodity contracts:				
Electricity	$ 43	$ 28	$ 10	$ 81
Natural gas	80	27	6	113
	$ 123	$ 55	$ 16	$ 194

PGE reports energy commodity derivative fair values as a net asset or liability, which combines purchases and sales expected to settle in the years noted above. As a short utility, energy commodity fair values exposed to commodity price risk are primarily related to purchase contracts, which are slightly offset by sales.

PGE's energy portfolio activities are subject to regulation, with related costs included in retail prices approved by the OPUC. The timing differences between the recognition of gains and losses on certain derivative instruments and their realization and subsequent recovery in prices are deferred as regulatory assets and regulatory liabilities to reflect the effects of regulation, significantly mitigating commodity price risk for the Company. As contracts are settled, these deferrals reverse and are recognized as Purchased power and fuel in the statements of income and included in the PCAM. PGE remains subject to cash flow risk in the form of collateral requirements based on the value of open positions and regulatory risk if recovery is disallowed by the OPUC. PGE attempts to mitigate both types of risks through prudent energy procurement practices.

Foreign Currency Exchange Rate Risk

PGE is exposed to foreign currency risk associated with natural gas forward and swap contracts denominated in Canadian dollars in its energy portfolio. Foreign currency risk is the risk of changes in value of pending financial obligations in foreign currencies that could occur prior to the settlement of the obligation due to a change in the value of that foreign currency in relation to the U.S. dollar. PGE monitors its exposure to fluctuations in the Canadian exchange rate with an appropriate hedging strategy.

As of December 31, 2012, a 10% change in the value of the Canadian dollar would result in an immaterial change in exposure for transactions that will settle over the next twelve months.

Interest Rate Risk

To meet short-term cash requirements, PGE has established a program under which it may from time to time issue commercial paper for terms of up to 270 days; such issuances are supported by the Company's unsecured revolving credit facilities. Although any borrowings under the commercial paper program subject the Company to fluctuations in interest rates, reflecting current market conditions, individual instruments carry a fixed rate during their respective terms. As of December 31, 2012, PGE had no borrowings outstanding under its revolving credit facilities and $17 million of commercial paper outstanding.

PGE currently has no financial instruments to mitigate risk related to changes in short-term interest rates, including those on commercial paper; however, it may consider such instruments in the future as considered necessary.

As of December 31, 2012, the total fair value and carrying amounts by maturity date of PGE's long-term debt are as follows (in millions):

	Total Fair Value	Carrying Amounts by Maturity Date						
		Total	2013	2014	2015	2016	2017	There-after
First Mortgage Bonds	$ 1,811	$ 1,515	$ 100	$ —	$ 70	$ 67	$ 58	$ 1,220
Pollution Control Revenue Bonds	138	121	—	—	—	—	—	121
Total	$ 1,949	$ 1,636	$ 100	$ —	$ 70	$ 67	$ 58	$ 1,341

As of December 31, 2012, PGE had no long-term variable rate debt outstanding; accordingly, the Company's outstanding long-term debt is not subject to interest rate risk exposures.

Credit Risk

PGE is exposed to credit risk in its commodity price risk management activities related to potential nonperformance by counterparties. PGE manages the risk of counterparty default according to its credit policies by performing financial credit reviews, setting limits and monitoring exposures, and requiring collateral (in the form of cash, letters of credit, and guarantees) when needed. The Company also uses standardized enabling agreements and, in certain cases, master netting agreements, which allow for the netting of positive and negative exposures under multiple agreements with counterparties. Despite such mitigation efforts, defaults by counterparties may periodically occur. Based upon periodic review and evaluation, allowances are recorded to reflect credit risk related to wholesale accounts receivable.

The large number and diversified base of residential, commercial, and industrial customers, combined with the Company's ability to discontinue service, contribute to reduce credit risk with respect to trade accounts receivable from retail sales. Estimated provisions for uncollectible accounts receivable related to retail sales are provided for such risk.

As of December 31, 2012, PGE's credit risk exposure is $3 million for commodity activities with externally-rated investment grade counterparties and matures in 2013. The credit risk is included in accounts receivable and price risk management assets, offset by related accounts payable and price risk management liabilities.

Investment grade includes those counterparties with a minimum credit rating on senior unsecured debt of Baa3 (as assigned by Moody's) or BBB- (as assigned by S&P), and also those counterparties whose obligations are guaranteed or secured by an investment grade entity. The credit exposure includes activity for electricity and natural gas forward, swap, and option contracts. Posted collateral may be in the form of cash or letters of credit and may represent prepayment or credit exposure assurance.

Omitted from the market risk exposures discussed above are long-term power purchase contracts with certain public utility districts in the state of Washington and with the City of Portland, Oregon. These contracts provide PGE with a percentage share of hydro facility output in exchange for an equivalent percentage share of operating and debt service costs. These contracts expire at varying dates through 2052. For additional information, see "*Public Utility Districts*" in Note 15, Commitments and Guarantees, in the Notes to Consolidated Financial Statements in Item 8. —"Financial Statements and Supplementary Data." Management believes that circumstances that could result in the nonperformance by these counterparties are remote.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

The following financial statements and report are included in Item 8:

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of
Portland General Electric Company
Portland, Oregon

We have audited the accompanying consolidated balance sheets of Portland General Electric Company and subsidiaries (the "Company") as of December 31, 2012 and 2011, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2012. We also have audited the Company's internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Portland General Electric Company and subsidiaries as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 21, 2013

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

	Years Ended December 31,		
	2012	2011	2010
Revenues, net	$ 1,805	$ 1,813	$ 1,783
Operating expenses:			
Purchased power and fuel	726	760	829
Production and distribution	211	201	174
Administrative and other	216	218	186
Depreciation and amortization	248	227	238
Taxes other than income taxes	102	98	89
Total operating expenses	1,503	1,504	1,516
Income from operations	302	309	267
Other income:			
Allowance for equity funds used during construction	6	5	13
Miscellaneous income, net	4	1	4
Other income, net	10	6	17
Interest expense	108	110	110
Income before income taxes	204	205	174
Income taxes	64	58	53
Net income	140	147	121
Less: net loss attributable to noncontrolling interests	(1)	—	(4)
Net income attributable to Portland General Electric Company	$ 141	$ 147	$ 125
Weighted-average shares outstanding (in thousands):			
Basic	75,498	75,333	75,275
Diluted	75,647	75,350	75,291
Earnings per share—basic and diluted	$ 1.87	$ 1.95	$ 1.66
Dividends declared per common share	$ 1.075	$ 1.055	$ 1.035

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)

	Years Ended December 31,		
	2012	2011	2010
Net income	$ 140	$ 147	$ 121
Other comprehensive income (loss)—Change in compensation retirement benefits liability and amortization, net of taxes of $1 in 2011 and 2010	—	(1)	1
Comprehensive income	140	146	122
Less: comprehensive loss attributable to the noncontrolling interests	(1)	—	(4)
Comprehensive income attributable to Portland General Electric Company	$ 141	$ 146	$ 126

See accompanying notes to consolidated financial statements.

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

	As of December 31,	
	2012	2011
ASSETS		
Current assets:		
Cash and cash equivalents	$ 12	$ 6
Accounts receivable, net	152	144
Unbilled revenues	97	101
Inventories, at average cost:		
Materials and supplies	38	37
Fuel	40	34
Margin deposits	46	80
Regulatory assets—current	144	216
Other current assets	93	98
Total current assets	622	716
Electric utility plant:		
Production	2,899	2,854
Transmission	412	393
Distribution	2,816	2,704
General	327	314
Intangible	357	331
Construction work in progress	140	120
Total electric utility plant	6,951	6,716
Accumulated depreciation and amortization	(2,559)	(2,431)
Electric utility plant, net	4,392	4,285
Regulatory assets—noncurrent	524	594
Nuclear decommissioning trust	38	37
Non-qualified benefit plan trust	32	36
Other noncurrent assets	62	65
Total assets	$ 5,670	$ 5,733

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS, continued
(In millions, except share amounts)

	As of December 31,	
	2012	2011
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 98	$ 111
Liabilities from price risk management activities—current	127	216
Short-term debt	17	30
Current portion of long-term debt	100	100
Accrued expenses and other current liabilities	179	157
Total current liabilities	521	614
Long-term debt, net of current portion	1,536	1,635
Regulatory liabilities—noncurrent	765	720
Deferred income taxes	588	529
Unfunded status of pension and postretirement plans	247	195
Non-qualified benefit plan liabilities	102	101
Asset retirement obligations	94	87
Liabilities from price risk management activities—noncurrent	73	172
Other noncurrent liabilities	14	14
Total liabilities	3,940	4,067
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	—	—
Common stock, no par value, 160,000,000 shares authorized; 75,556,272 and 75,362,956 shares issued and outstanding as of December 31, 2012 and 2011, respectively	841	836
Accumulated other comprehensive loss	(6)	(6)
Retained earnings	893	833
Total Portland General Electric Company shareholders' equity	1,728	1,663
Noncontrolling interests' equity	2	3
Total equity	1,730	1,666
Total liabilities and equity	$ 5,670	$ 5,733

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY
(In millions, except share amounts)

	Portland General Electric Company Shareholders' Equity				
	Common Stock		Accumulated Other Comprehensive Loss	Retained Earnings	Noncontrolling Interests' Equity
	Shares	Amount			
Balance as of December 31, 2009	75,210,580	$ 829	$ (6)	$ 719	$ 1
Shares issued pursuant to equity-based plans	105,839	1	—	—	—
Noncontrolling interests' capital contributions	—	—	—	—	10
Stock-based compensation	—	1	—	—	—
Dividends declared	—	—	—	(78)	—
Net income (loss)	—	—	—	125	(4)
Other comprehensive income	—	—	1	—	—
Balance as of December 31, 2010	75,316,419	831	(5)	766	7
Shares issued pursuant to equity-based plans	46,537	1	—	—	—
Noncontrolling interests' capital distributions	—	—	—	—	(4)
Stock-based compensation	—	4	—	—	—
Dividends declared	—	—	—	(80)	—
Net income	—	—	—	147	—
Other comprehensive loss	—	—	(1)	—	—
Balance as of December 31, 2011	75,362,956	836	(6)	833	3
Shares issued pursuant to equity-based plans	193,316	1	—	—	—
Stock-based compensation	—	4	—	—	—
Dividends declared	—	—	—	(81)	—
Net income (loss)	—	—	—	141	(1)
Balance as of December 31, 2012	75,556,272	$ 841	$ (6)	$ 893	$ 2

See accompanying notes to consolidated financial statements.

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

	Years Ended December 31,		
	2012	2011	2010
Cash flows from operating activities:			
Net income	$ 140	$ 147	$ 121
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	248	227	238
Deferred income taxes	47	56	67
Renewable adjustment clause deferrals	1	22	(12)
Pension and other postretirement benefits	27	15	11
Regulatory deferral of settled derivative instruments	(9)	12	26
Power cost deferrals, net of amortization	(4)	10	(1)
(Decrease) increase in net liabilities from price risk management activities	(175)	9	118
Regulatory deferrals—price risk management activities	172	(6)	(118)
Allowance for equity funds used during construction	(6)	(5)	(13)
Decoupling mechanism deferrals, net of amortization	2	3	(10)
Unrealized losses (gains) on non-qualified benefit plan trust assets.	3	—	(5)
Other non-cash income and expenses, net	16	16	3
Changes in working capital:			
(Increase) decrease in receivables and unbilled revenues	(4)	(15)	24
Decrease (increase) in margin deposits	34	3	(27)
Income tax refund received	8	9	53
Increase in income taxes receivable	—	—	(22)
Increase (decrease) in payables and accrued liabilities	1	5	(11)
Other working capital items, net	1	(7)	—
Contribution to pension plan	—	(26)	(30)
Contribution to voluntary employees' benefit association trust	(2)	(16)	(1)
Other, net	(6)	(6)	(20)
Net cash provided by operating activities	494	453	391
Cash flows from investing activities:			
Capital expenditures	(303)	(300)	(450)
Purchases of nuclear decommissioning trust securities	(26)	(50)	(46)
Sales of nuclear decommissioning trust securities	23	46	50
Distribution from nuclear decommissioning trust	—	—	19
Proceeds from sale of solar power facility	10	—	—
Other, net	2	5	(3)
Net cash used in investing activities	(294)	(299)	(430)

See accompanying notes to consolidated financial statements.

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

	Years Ended December 31, 2012	2011	2010
Cash flows from financing activities:			
Proceeds from issuance of long-term debt	$ —	$ —	$ 249
Payments on long-term debt	(100)	(73)	(186)
(Maturities) issuances of commercial paper, net	(13)	11	19
Borrowings on short-term debt	—	—	11
Payments on short-term debt	—	—	(11)
Dividends paid	(81)	(79)	(78)
Premium paid on repayment of long-term debt	—	(7)	—
Debt issuance costs	—	—	(2)
Noncontrolling interests' capital (distributions) contributions	—	(4)	10
Net cash (used in) provided by financing activities	(194)	(152)	12
Change in cash and cash equivalents	6	2	(27)
Cash and cash equivalents, beginning of year	6	4	31
Cash and cash equivalents, end of year	$ 12	$ 6	$ 4
Supplemental disclosures of cash flow information:			
Cash paid for interest, net of amounts capitalized	$ 97	$ 103	$ 98
Cash paid for income taxes	13	3	—
Non-cash investing and financing activities:			
Accrued capital additions	19	19	12
Accrued dividends payable	21	21	20
Preliminary engineering transferred to Construction work in progress from Other noncurrent assets	—	7	—

See accompanying notes to consolidated financial statements.

NOTE 1: BASIS OF PRESENTATION

Nature of Operations

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 marketers. 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 is located in Portland, Oregon and its service area is located entirely within Oregon. PGE's service area includes 52 incorporated cities, of which Portland and Salem are the largest, within a state-approved service area allocation of approximately 4,000 square miles. As of December 31, 2012, PGE served 828,354 retail customers with a service area population of approximately 1.7 million, comprising approximately 44% of the state's population.

As of December 31, 2012, PGE had 2,603 employees, with 809 employees covered under two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 775 and 34 employees and expire in February 2015 and August 2014, respectively.

PGE is subject to the jurisdiction of the Public Utility Commission of Oregon (OPUC) with respect to retail prices, utility services, accounting policies and practices, issuances of securities, and certain other matters. Retail prices are based on the Company's cost to serve customers, including an opportunity to earn a reasonable rate of return, as determined by the OPUC. The Company is also subject to regulation by the Federal Energy Regulatory Commission (FERC) in matters related to wholesale energy transactions, transmission services, reliability standards, natural gas pipelines, hydroelectric project licensing, accounting policies and practices, short-term debt issuances, and certain other matters.

Consolidation Principles

The consolidated financial statements include the accounts of PGE and its wholly-owned subsidiaries and those variable interest entities (VIEs) where PGE has determined it is the primary beneficiary. The Company's ownership share of direct expenses and costs related to jointly-owned generating plants are also included in its consolidated financial statements. Intercompany balances and transactions have been eliminated.

For entities that are determined to meet the definition of a VIE and where the Company has determined it is the primary beneficiary, the VIE is consolidated and a noncontrolling interest is recognized for any third party interests. This has resulted in the Company consolidating entities in which it has less than a 50% equity interest. For further information, see Note 16, Variable Interest Entities.

Use of Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America (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 could differ materially from those estimates.

Reclassifications

To conform with the 2012 presentation, PGE has separately presented Deferred income tax assets from Other current assets and Asset retirement obligations (AROs) from Other noncurrent liabilities, as well as reclassified $6 million of Regulatory liabilities—current to Accrued expenses and other current liabilities in the 2011 consolidated balance sheet. In addition, PGE has separately presented Pension and other postretirement benefits of $15 million and $11 million from, and collapsed Senate Bill 408 amortization of $7 million in 2011 and $13 million in 2010 into, Other non-cash income and expenses, net in the operating activities section of the statements of cash flows for the years ended December 31, 2011 and 2010, respectively.

NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cash and Cash Equivalents

Highly liquid investments with maturities of three months or less at the date of acquisition are classified as cash equivalents, of which PGE had none as of December 31, 2012 and 2011.

Accounts Receivable

Accounts receivable are recorded at invoiced amounts and do not bear interest when recorded. Late payment fees on balances in arrears are first assessed 16 business days after the due date. An inactive account balance is charged-off in the period in which the receivable is deemed uncollectible, but no sooner than 45 business days after the final due date.

Estimated provisions for uncollectible accounts receivable related to retail sales, charged to Administrative and other expense, are recorded in the same period as the related revenues, with an offsetting credit to the allowance for uncollectible accounts. Such estimates are based on management's assessment of the probability of collection of customer accounts, aging of accounts receivable, bad debt write-offs, actual customer billings, and other factors.

Provisions related to wholesale accounts receivable and unsettled positions, charged to Purchased power and fuel expense, are based on a periodic review and evaluation that includes counterparty non-performance risk and contractual rights of offset when applicable. Actual amounts written off are charged to the allowance for uncollectible accounts.

Price Risk Management

PGE engages in price risk management activities, utilizing financial instruments such as forward, swap, and option contracts for electricity, natural gas, oil and foreign currency. These instruments are measured at fair value and recorded on the consolidated balance sheets as assets or liabilities from price risk management activities, unless they qualify for the normal purchases and normal sales exception. Changes in fair value are recognized in the statement of income, offset by the effects of regulatory accounting.

Certain electricity forward contracts that were entered into in anticipation of serving the Company's regulated retail load meet the requirements for treatment under the normal purchases and normal sales exception. Other activities consist of certain electricity forwards, options and swaps, certain natural gas forwards, options, and swaps, and forward contracts for acquiring Canadian dollars. Such activities are utilized as economic hedges to protect against variability in expected future cash flows due to associated price risk and to manage exposure to volatility in net power costs for the Company's retail customers.

In accordance with ratemaking and cost recovery processes authorized by the OPUC, PGE recognizes a regulatory asset or liability to defer unrealized losses or gains, respectively, on derivative instruments until settlement. At the time of settlement, PGE recognizes a realized gain or loss on the derivative instrument. Contracts that qualify for the normal purchases and normal sales exception are not required to be recorded at fair value.

Physical electricity sale and purchase transactions are recorded in Revenues and Purchased power and fuel expense upon settlement, respectively, while financial transactions are recorded on a net basis in Purchased power and fuel expense upon settlement.

Pursuant to transactions entered into in connection with PGE's price risk management activities, the Company may be required to provide collateral with certain counterparties. The collateral requirements are based on the contract terms and commodity prices and can vary period to period. Cash deposits provided as collateral are classified as Margin deposits in the accompanying consolidated balance sheets and were $46 million and $80 million as of December 31, 2012 and 2011, respectively. Letters of credit provided as collateral are not recorded on the Company's consolidated balance sheet and were $45 million and $104 million as of December 31, 2012 and 2011, respectively.

Inventories

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

Electric Utility Plant

Capitalization Policy

Electric utility plant is capitalized at its original cost. Costs include direct labor, materials and supplies, and contractor costs, as well as indirect costs such as engineering, supervision, employee benefits, and an allowance for funds used during construction (AFDC). Plant replacements are capitalized, with minor items charged to expense as incurred. Periodic major maintenance inspections and overhauls at the Company's generating plants are charged to expense as incurred, subject to regulatory accounting as applicable. Costs to purchase or develop software applications for internal use only are capitalized and amortized over the estimated useful life of the software. Costs of obtaining a FERC license for the Company's hydroelectric projects are capitalized and amortized over the related license period.

During the period of construction, costs expected to be included in the final value of the constructed asset, and depreciated once the asset is complete and placed in service, are classified as Construction work in progress in Electric utility plant on the consolidated balance sheets. If the project becomes probable of being abandoned, such costs are expensed in the period such determination is made. If any costs are expensed, the Company may seek recovery of such costs in customer prices, although there can be no guarantee such recovery would be granted.

PGE records AFDC, which is intended to represent the Company's cost of funds used for construction purposes and is based on the rate granted in the latest general rate case for equity funds and the cost of actual borrowings for debt funds. AFDC is capitalized as part of the cost of plant and credited to the consolidated statements of income. The average rate used by PGE was 7.5% in 2012, 7.8% in 2011 and 7.6% in 2010. AFDC from borrowed funds was $4 million in 2012, $3 million in 2011, and $9 million in 2010 and is reflected as a reduction to Interest expense. AFDC from equity funds was $6 million in 2012, $5 million in 2011, and $13 million in 2010 and is reflected as a component of Other income, net.

Costs which are disallowed for recovery in customer prices are charged to expense at the time such disallowance is probable.

Depreciation and Amortization

Depreciation is computed using the straight-line method, based upon original cost, and includes an estimate for cost of removal and expected salvage. Depreciation expense as a percent of the related average depreciable plant in service was 3.8% in 2012, 3.7% in 2011, and 3.9% in 2010. Estimated asset retirement removal costs included in depreciation expense were $55 million for the year ended December 31, 2012, with $49 million in 2011 and $47 million in 2010.

Periodic studies are conducted to update depreciation parameters (i.e. retirement dispersion patterns, average service lives, and net salvage rates), including estimates of AROs and asset retirement removal costs. The studies are conducted every five years and are filed with the OPUC for approval and inclusion in a future rate proceeding. In September 2010, PGE received an order from the OPUC authorizing new depreciation rates to be effective January 2011.

Thermal production plants are depreciated using a life-span methodology which ensures that plant investment is recovered by the estimated retirement dates, which range from 2020 to 2050. Depreciation is provided on the Company's other classes of plant in service over their estimated average service lives, which are as follows (in years):

Production, excluding thermal:	
Hydro	87
Wind	27
Transmission	53
Distribution	40
General	13

The original cost of depreciable property units, net of any related salvage value, is charged to accumulated depreciation when property is retired and removed from service. Cost of removal expenditures are recorded against AROs or to accumulated asset retirement removal costs, included in Regulatory liabilities, for assets without AROs.

In June 2011, PGE received an order from the OPUC authorizing an increase in customer prices effective July 1, 2011 for depreciation expense and decommissioning costs related to the Company's commitment to cease coal-fired operations at Boardman at the end of 2020.

Intangible plant consists primarily of computer software development costs, which are amortized over either five or ten years, and hydro licensing costs, which are amortized over the applicable license term, which range from 30 to 50 years. Accumulated amortization was $151 million and $153 million as of December 31, 2012 and 2011, respectively, with amortization expense of $22 million in 2012, $19 million in 2011, and $17 million in 2010. Future estimated amortization expense as of December 31, 2012 is as follows: $20 million in 2013; $18 million in 2014; $16 million in 2015; $14 million in 2016; and $11 million in 2017.

Marketable Securities

All of PGE's investments in marketable securities, included in the Non-qualified benefit plan trust and Nuclear decommissioning trust on the consolidated balance sheets, are classified as trading. Trading securities are stated at fair value based on quoted market prices. Realized and unrealized gains and losses on the Non-qualified benefit plan trust assets are included in Other income, net. Realized and unrealized gains and losses on the Nuclear decommissioning trust fund assets are recorded as regulatory liabilities or assets, respectively, for future ratemaking. The cost of securities sold is based on the average cost method.

Regulatory Accounting

Regulatory Assets and Liabilities

As a rate-regulated enterprise, the Company applies regulatory accounting, resulting in regulatory assets or regulatory liabilities. Regulatory assets represent (i) probable future revenue associated with certain actual or estimated costs that are expected to be recovered from customers through the ratemaking process, or (ii) probable future collections from customers resulting from revenue accrued for completed alternative revenue programs, provided certain criteria are met. Regulatory liabilities represent probable future reductions in revenue associated with amounts that are expected to be credited to customers through the ratemaking process. Regulatory accounting is appropriate as long as prices are established by or subject to approval by independent third-party regulators; prices are designed to recover the specific enterprise's cost of service; and in view of demand for service, it is reasonable to assume that prices set at levels that will recover costs can be charged to and collected from customers. Once the regulatory asset or liability is reflected in prices, the respective regulatory asset or liability is amortized to the appropriate line item in the statement of income over the period in which it is included in prices.

Circumstances that could result in the discontinuance of regulatory accounting include (i) increased competition that restricts the Company's ability to establish prices to recover specific costs, and (ii) a significant change in the manner in which prices are set by regulators from cost-based regulation to another form of regulation. PGE periodically reviews the criteria of regulatory accounting to ensure that its continued application is appropriate. Based on a current evaluation of the various factors and conditions, management believes that recovery of the Company's regulatory assets is probable.

For additional information concerning the Company's regulatory assets and liabilities, see Note 6, Regulatory Assets and Liabilities.

Power Cost Adjustment Mechanism

PGE is subject to a power cost adjustment mechanism (PCAM) as approved by the OPUC. Pursuant to the PCAM, the Company can adjust future customer prices to reflect a portion of the difference between each year's forecasted net variable power costs (NVPC) included in customer prices (baseline NVPC) and actual NVPC. PGE is subject to a portion of the business risk or benefit associated with the difference between actual NVPC and baseline NVPC by application of an asymmetrical "deadband," which ranges from $15 million below to $30 million above baseline NVPC. If the difference between actual NVPC, as determined pursuant to the PCAM, and baseline NVPC falls within the established deadband range, PGE absorbs the incremental cost or benefit, with any difference falling outside the lower and upper thresholds of the deadband range being shared 90/10 between customers and the Company, respectively. Any customer refund or collection is also subject to a regulated earnings test. A refund occurs to the extent that it results in PGE's actual regulated return on equity (ROE) for that year being no less than 1% above the Company's authorized ROE. A collection occurs to the extent that it results in PGE's actual regulated ROE for that year being no greater than 1% below the Company's authorized ROE. PGE's authorized ROE was 10% for 2012, 2011 and 2010. A final determination of any customer refund or collection is made in the following year by the OPUC through a public filing and review.

PGE estimates and records amounts related to the PCAM on a quarterly basis during the year. If the projected difference between baseline and actual NVPC for the year exceeds the higher end of the established deadband, and if forecasted earnings exceed the level required by the regulated earnings test, a regulatory liability is recorded for any future amount payable to retail customers, with offsetting amounts recorded to Purchased power and fuel expense. If the difference is below the lower end of the established deadband, a regulatory asset is recorded for any future amount due from retail customers, with offsetting amounts recorded to Revenues.

For 2012, actual NVPC was below baseline NVPC by $17 million, and exceeded the lower deadband threshold of $15 million. However, based on results of the regulated earnings test, no estimated refund to customers was recorded as of December 31, 2012. A final determination regarding the 2012 PCAM results will be made by the OPUC through a public filing and review in 2013.

For 2011, actual NVPC was below baseline NVPC by $34 million, and exceeded the lower deadband threshold of $15 million. PGE recorded an estimated refund to customers of $10 million, reduced from the $17 million potential refund to customers as a result of the regulated earnings test. A final determination regarding the 2011 PCAM results was made by the OPUC through a public filing and review in 2012, which, based upon the application of an updated regulated earnings test, resulted in a revised refund to customers of $6 million to be returned to customers over a one-year period beginning January 1, 2013.

For 2010, actual NVPC was below baseline NVPC by $12 million, which is within the established deadband range. Accordingly, no customer refund was recorded as of December 31, 2010. A final determination regarding the 2010 PCAM results was made by the OPUC through a public filing and review in 2011, which confirmed that no customer refund was warranted for 2010.

Asset Retirement Obligations

An ARO is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. PGE recognizes those legal obligations related to dismantlement and restoration costs associated with the future retirement of tangible long-lived assets. Due to the long lead time involved until decommissioning activities occur, the Company uses present value techniques because quoted market prices and a market-risk premium are not available. The present value of estimated future removal expenditures is capitalized as an ARO on the consolidated balance sheets and revised periodically, with actual expenditures charged to the ARO as incurred.

The estimated capitalized costs of AROs are depreciated over the estimated life of the related asset, which is included in Depreciation and amortization in the consolidated statements of income.

Contingencies

Contingencies are evaluated using the best information available at the time the consolidated financial statements are prepared. Loss contingencies are accrued, and disclosed if material, when it is probable that an asset has been impaired or a liability incurred as of the financial statement date and the amount of the loss can be reasonably estimated. If a reasonable estimate of probable loss cannot be determined, a range of loss may be established, in which case the minimum amount in the range is accrued, unless some other amount within the range appears to be a better estimate. Legal costs incurred in connection with loss contingencies are expensed as incurred.

A loss contingency will also be disclosed when it is reasonably possible that an asset has been impaired or a liability incurred if the estimate or range of potential loss is material. If a probable or reasonably possible loss cannot be reasonably estimated, disclosure of the loss contingency includes a statement to that effect and the reasons.

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

Gain contingencies are recognized when realized and are disclosed when material.

Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss (AOCL) presented on the consolidated balance sheets is comprised of the difference between the non-qualified benefit plans' obligations recognized in net income and the unfunded position.

Revenue Recognition

Revenues are recognized as electricity is delivered to customers and include amounts for any services provided. The prices charged to customers are subject to federal (FERC), and state (OPUC) regulation. Franchise taxes, which are collected from customers and remitted to taxing authorities, are recorded on a gross basis in PGE's consolidated statements of income. Amounts collected from customers are included in Revenues, net and amounts due to taxing authorities are included in Taxes other than income taxes and totaled $42 million in 2012, $41 million in 2011, and $39 million in 2010.

Retail revenue is billed monthly based on meter readings taken throughout the month. Unbilled revenue represents the revenue earned from the last meter read date through the last day of the month, which has not been billed as of the last day of the month. Unbilled revenue is calculated based on each month's actual net retail system load, the number of days from the last meter read date through the last day of the month, and current retail customer prices.

As a rate-regulated utility, there are situations in which PGE accrues revenue to be billed to customers in future periods or defers the recognition of certain revenues to the period in which the related costs are incurred or approved by the OPUC for amortization. For additional information, see "*Regulatory Assets and Liabilities*" in this Note 2.

Stock-Based Compensation

The measurement and recognition of compensation expense for all share-based payment awards, including restricted stock units, is based on the estimated fair value of the awards. The fair value of the portion of the award that is ultimately expected to vest is recognized as expense over the requisite service period. PGE attributes the value of stock-based compensation to expense on a straight-line basis.

Income Taxes

Income taxes are accounted for under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between financial statement carrying amounts and tax bases of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in current and future periods that includes the enactment date. Any valuation allowance is established to reduce deferred tax assets to the "more likely than not" amount expected to be realized in future tax returns.

As a rate-regulated enterprise, changes in deferred tax assets and liabilities that are related to certain property are required to be passed on to customers through future prices and are charged or credited directly to a regulatory asset or regulatory liability. These amounts were recognized as net regulatory assets of $80 million and $87 million as of December 31, 2012 and 2011, respectively, and will be included in prices when the temporary differences reverse.

Unrecognized tax benefits represent management's expected treatment of a tax position taken in a filed tax return, or planned to be taken in a future tax return, that has not been reflected in measuring income tax expense for financial reporting purposes. Until such positions are no longer considered uncertain, PGE would not recognize the tax benefits resulting from such positions and would report the tax effect as a liability in the Company's consolidated balance sheet.

PGE records any interest and penalties related to income tax deficiencies in Interest expense and Other income, net, respectively, in the consolidated statements of income.

Recent Accounting Pronouncements

Accounting Standards Update (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) changed the wording used to describe principles and requirements to align with International Financial Reporting Standards as issued by the International Accounting Standards Board, and were 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 adopted the amendments contained in ASU 2011-04 on January 1, 2012, which did not have an impact on the Company's consolidated financial position, consolidated results of operations, or consolidated cash flows.

ASU 2011-11, *Balance Sheet (Topic 210) - Disclosures about Offsetting Assets and Liabilities* (ASU 2011-11) requires an entity to disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. The amendments in ASU 2011-11 are to be applied for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. Disclosures required by ASU 2011-11 shall be provided retrospectively for all comparative periods presented. PGE will adopt the amendments contained in ASU 2011-11 on January 1, 2013, which is not expected to have an impact on the Company's consolidated financial position, consolidated results of operations, or consolidated cash flows.

NOTE 3: BALANCE SHEET COMPONENTS

Accounts Receivable, Net

Accounts receivable is net of an allowance for uncollectible accounts of $5 million and $6 million as of December 31, 2012 and 2011, respectively. The following is the activity in the allowance for uncollectible accounts (in millions):

	Years Ended December 31,		
	2012	2011	2010
Balance as of beginning of year	$ 6	$ 5	$ 5
Increase in provision	6	11	7
Amounts written off, less recoveries	(7)	(10)	(7)
Balance as of end of year	$ 5	$ 6	$ 5

Trust Accounts

PGE maintains two trust accounts as follows:

Nuclear decommissioning trust—Reflects assets held in trust to cover general decommissioning costs and operation of the Independent Spent Fuel Storage Installation (ISFSI) and represent amounts collected from customers less qualified expenditures plus any realized and unrealized gains and losses on the investments held therein.

Non-qualified benefit plan trust—Reflects assets held in trust to cover the obligations of PGE's non-qualified benefit plans and represents contributions made by the Company less qualified expenditures plus any realized and unrealized gains and losses on the investment held therein.

The trusts are comprised of the following investments as of December 31 (in millions):

	Nuclear Decommissioning Trust		Non-Qualified Benefit Plan Trust	
	2012	2011	2012	2011
Cash equivalents	$ 15	$ 14	$ 2	$ —
Marketable securities, at fair value:				
Equity securities	—	—	5	10
Debt securities	23	23	2	3
Insurance contracts, at cash surrender value	—	—	23	23
	$ 38	$ 37	$ 32	$ 36

For information concerning the fair value measurement of those assets recorded at fair value held in the trusts, see Note 4, Fair Value of Financial Instruments.

Other Current Assets and Accrued Expenses and Other Current Liabilities

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

	As of December 31,	
	2012	2011
Other current assets:		
Current deferred income tax asset	$ 51	$ 33
Assets from price risk management activities	4	19
Income taxes receivable	1	12
Other	37	34
	$ 93	$ 98
Accrued expenses and other current liabilities:		
Accrued employee compensation and benefits	$ 46	$ 44
Accrued interest payable	23	24
Dividends payable	21	21
Regulatory liabilities—current	12	6
Other	77	62
	$ 179	$ 157

Other Noncurrent Assets

The Company incurs preliminary engineering costs related to potential future capital projects, which are capitalized in Other noncurrent assets in the consolidated balance sheets. Preliminary engineering costs consist of expenditures for preliminary surveys, plans, and investigations made for the purpose of determining the feasibility of utility projects being considered. Once the project is approved for construction, such costs are reclassified to Construction work in progress within Electric utility plant. If the project is abandoned, such costs are expensed to Production and distribution expense in the period such determination is made. If any preliminary engineering costs are expensed, the Company may seek recovery of such costs in customer prices, although there can be no guarantee such recovery would be granted. As of December 31, 2012 and 2011, PGE has recorded preliminary engineering costs of $14 million and $10 million, respectively. For the years ended December 31, 2012, 2011, and 2010, no material preliminary engineering costs were expensed.

NOTE 4: FAIR VALUE OF FINANCIAL INSTRUMENTS

PGE determines the fair value of financial instruments, both assets and liabilities recognized and not recognized in the Company's consolidated balance sheets, for which it is practicable to estimate fair value as of December 31, 2012 and 2011, and then classifies these financial assets and liabilities based on a fair value hierarchy. The fair value hierarchy is used to prioritize the inputs to the valuation techniques used to measure fair value. These three 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.

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

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

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy.

PGE recognizes transfers between levels in the fair value hierarchy as of the end of the reporting period for all of its financial instruments. Changes to market liquidity conditions, the availability of observable inputs, or changes in the economic structure of a security marketplace may require transfer of the securities between levels. There were no significant transfers between levels during each of the years ended December 31, 2012, 2011 and 2010, except those net transfers out of Level 3 to Level 2 presented in this note.

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

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

(1) Activities are subject to regulation, with certain gains and losses deferred pursuant to regulatory accounting and included in regulatory assets or regulatory liabilities as appropriate.
(2) Excludes insurance policies of $23 million, which are recorded at cash surrender value.
(3) For further information, see Note 5, Price Risk Management.

	As of December 31, 2011			
	Level 1	Level 2	Level 3	Total
Assets:				
Nuclear decommissioning trust (1):				
Money market funds	$ —	$ 14	$ —	$ 14
Debt securities:				
Domestic government	3	9	—	12
Corporate credit	—	11	—	11
Non-qualified benefit plan trust (2):				
Equity securities:				
Domestic	7	2	—	9
International	1	—	—	1
Debt securities - domestic government	3	—	—	3
Assets from price risk management activities (1) (3):				
Electricity	—	2	—	2
Natural gas	—	17	—	17
	$ 14	$ 55	$ —	$ 69
Liabilities - Liabilities from price risk management activities (1) (3):				
Electricity	$ —	$ 108	$ 29	$ 137
Natural gas	—	201	50	251
	$ —	$ 309	$ 79	$ 388

(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 5, Price Risk Management.

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

Money market funds—PGE invests in money market funds that seek to maintain a stable net asset value. These funds invest in high-quality, short-term, diversified money market instruments, short-term treasury bills, federal agency securities, certificates of deposits, and commercial paper. Money market funds are classified as Level 2 in the fair value hierarchy as the securities are traded in active markets of similar securities but are not directly valued using quoted market prices.

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

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

Equity securities—Equity mutual fund and common stock securities are primarily classified as Level 1 in the fair value hierarchy due to the availability of quoted prices for identical assets in an active market as of the reporting date. Principal markets for equity prices include published exchanges such as NASDAQ and the New York Stock Exchange (NYSE). Certain mutual fund assets included in commingled trusts or separately managed accounts are classified as Level 2 in the fair value hierarchy as pricing inputs are directly or indirectly observable in the marketplace.

Assets and liabilities from price risk management activities are recorded at fair value in PGE's consolidated balance sheets and consist of derivative instruments entered into by the Company to manage its exposure to commodity price risk and foreign currency exchange rate risk, and reduce volatility in net power costs for the Company's retail customers. For additional information regarding these assets and liabilities, see Note 5, Price Risk Management.

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

Assets and liabilities from price risk management activities classified as Level 3 consist of instruments for which fair value is derived using one or more significant inputs that are not observable for the entire term of the instrument. These instruments consist of longer term over-the-counter swap derivatives. Commodity option contracts whose fair value is derived using standardized valuation techniques, such as Black-Scholes, are also classified as Level 3. Inputs into the valuation of commodity option contracts include forward commodity prices, forward interest rates, and historic volatility and correlation factors.

The Company values its Level 3 assets and liabilities from price risk management activities using a discounted cash flow valuation technique in which quoted forward prices for the respective commodity are significant unobservable inputs. Quantitative information regarding the significant, unobservable inputs used in the measurement of Level 3 assets and liabilities from price risk management activities as of December 31, 2012 is presented below:

	Fair Value	Range and Weighted Average Price per Unit			
		Low	High	Weighted Average	Unit
Assets from price risk management activities:	(in millions)				
Natural gas financial swaps	$ 2	$ 3.74	$ 5.21	$ 4.36	Dth
Liabilities from price risk management activities:					
Electricity financial swaps and commodity futures	10	7.12	51.72	41.14	MWh
Natural gas financial swaps	8	3.67	5.21	4.20	Dth

Long-term forward prices for commodity derivatives employ the mid-point of the market's bid-ask spread and are derived using observed transactions in active markets, as well as historical experience as a participant in those markets.

The Company's Risk Management department, which reports to the Chief Financial Officer, prepares valuations for all derivative transactions. This process includes management of the mark-to-market process, which ultimately determines the fair value measurement for assets and liabilities from price risk management activities. On a daily basis, mark-to-market valuations for derivatives are calculated using the Company's system of record. Inputs used in performing daily mark-to-market calculations are uploaded into the system of record after review for reasonableness against expectations and subsequent to validation against broker quotes and market data from a regulated exchange. In addition, the overall change in mark-to-market is evaluated based on pricing input expectations. Any discrepancies identified during this process may result in adjustment of an input.

PGE's Level 3 assets and liabilities from price risk management activities are sensitive to market price changes in the respective underlying commodities. The significance of the impact is dependent upon the magnitude of the price change and the Company's position as either the buyer or seller of the contract. As the buyer of a commodity financial swap, an increase in the underlying commodity price would result in a favorable change to the fair value measurement. Conversely, a decrease in the underlying commodity price would result in an unfavorable change to the fair value measurement. As the seller of a commodity financial swap, the fair value measurements are sensitive to price changes in a manner opposite to the buy side relationship discussed above.

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):

	Years Ended December 31,	
	2012	2011
Net liabilities from price risk management activities as of beginning of year	$ 79	$ 120
Net realized and unrealized losses	15 (1)	86
Purchases	(1)	3
Issuances	(1)	—
Settlements	—	(1)
Net transfers out of Level 3 to Level 2	(76)	(129)
Net liabilities from price risk management activities as of end of year	$ 16	$ 79
Level 3 net unrealized losses that have been fully offset by the effect of regulatory accounting	$ 14	$ 88

(1) Includes $1 million of realized losses, net.

The comparable information contained in the preceding table was as follows for the year ended December 31, 2010 (in millions):

Net liabilities from price risk management activities as of beginning of year	$ 154
Net realized and unrealized losses (1)	65
Purchases, issuances, and settlements, net	27
Net transfers out of Level 3 to Level 2	(126)
Net liabilities from price risk management activities as of end of year	$ 120
Level 3 net unrealized losses that have been fully offset by the effect of regulatory accounting	$ 95

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

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.

Long-term debt is recorded at amortized cost in PGE's consolidated balance sheets. The fair value of long-term debt is classified as a Level 2 fair value measurement and is estimated based on the quoted market prices for the same or similar issues or on the current rates offered to PGE for debt of similar remaining maturities. As of

December 31, 2012, the estimated aggregate fair value of PGE's long-term debt was $1,949 million, compared to its $1,636 million carrying amount. As of December 31, 2011, the estimated aggregate fair value of PGE's long-term debt was $2,091 million, compared to its $1,735 million carrying amount.

For fair value information concerning the Company's pension plan assets, see Note 10, Employee Benefits.

NOTE 5: 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 fuel and power purchases and sales resulting from economic dispatch decisions for its own 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, performance, or cash flow.

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

PGE has elected to report gross on the consolidated balance sheets the positive and negative exposures resulting from derivative instruments entered into with counterparties where a master netting arrangement exists. As of December 31, 2012 and 2011, the Company had $18 million and $26 million, respectively, in collateral posted with these counterparties, consisting entirely of letters of credit.

PGE's net volumes related to its Assets and Liabilities from price risk management activities resulting from its derivative transactions, which are expected to deliver or settle at various dates through 2016, were as follows (in millions):

	As of December 31,					
	2012			2011		
Commodity contracts:						
Electricity		11	MWh		13	MWh
Natural gas		86	Decatherms		79	Decatherms
Foreign currency exchange	$	7	Canadian	$	6	Canadian

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

	As of December 31,	
	2012	2011
Current assets:		
Commodity contracts:		
Electricity	$ 1	$ 2
Natural gas	3	17
Total current derivative assets	4 (1)	19 (1)
Noncurrent assets:		
Commodity contracts:		
Natural gas	2 (2)	—
Total derivative assets not designated as hedging instruments	$ 6	$ 19
Total derivative assets	$ 6	$ 19
Current liabilities:		
Commodity contracts:		
Electricity	$ 44	$ 66
Natural gas	83	150
Total current derivative liabilities	127	216
Noncurrent liabilities:		
Commodity contracts:		
Electricity	38	71
Natural gas	35	101
Total noncurrent derivative liabilities	73	172
Total derivative liabilities not designated as hedging instruments	$ 200	$ 388
Total derivative liabilities	$ 200	$ 388

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

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

	Years Ended December 31,		
	2012	2011	2010
Commodity contracts:			
Electricity	$ 56	$ 117	$ 127
Natural Gas	19	98	192

Net unrealized losses and certain net realized losses presented in the table above are offset within the statement of income by the effects of regulatory accounting. Of the net loss recognized in net income for the years ended December 31, 2012, 2011, and 2010, $42 million, $192 million, and $258 million, respectively, have been offset.

Assuming no changes in market prices and interest rates, the following table indicates the year in which the net unrealized loss recorded as of December 31, 2012 related to PGE's derivative activities would be realized as a result of the settlement of the underlying derivative instrument (in millions):

	2013	2014	2015	Total
Commodity contracts:				
Electricity	$ 43	$ 28	$ 10	$ 81
Natural gas	80	27	6	113
Net unrealized loss	$ 123	$ 55	$ 16	$ 194

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 some other counterparties will 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 December 31, 2012 was $163 million, for which the Company had $45 million in posted collateral, consisting entirely of letters of credit. If the credit-risk-related contingent features underlying these agreements were triggered at December 31, 2012, the cash requirement to either post as collateral or settle the instruments immediately would have been $157 million.

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

	As of December 31,	
	2012	2011
Assets from price risk management activities:		
Counterparty A	21%	19%
Counterparty B	13	2
Counterparty C	11	16
Counterparty D	10	9
Counterparty E	6	13
	61%	59%
Liabilities from price risk management activities:		
Counterparty F	24%	23%
Counterparty G	14	10
Counterparty H	10	6
	48%	39%

For additional information concerning the determination of fair value for the Company's Assets and Liabilities from price risk management activities, see Note 4, Fair Value of Financial Instruments.

NOTE 6: REGULATORY ASSETS AND LIABILITIES

The majority of PGE's regulatory assets and liabilities are reflected in customer prices and are amortized over the period in which they are reflected in customer prices. Items not currently reflected in prices are pending before the regulatory body as discussed below.

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

	Weighted Average Remaining Life [1]	As of December 31, 2012 Current	2012 Noncurrent	2011 Current	2011 Noncurrent
Regulatory assets:					
Price risk management [2]	2 years	$ 123	$ 71	$ 194	$ 172
Pension and other postretirement plans [2]	[3]	—	321	—	295
Deferred income taxes [2]	[4]	—	80	—	87
Deferred broker settlements [2]	1 year	20	1	11	—
Debt issuance costs [2]	7 years	—	22	—	28
Deferred capital projects	[5]	—	16	—	—
Other [6]	Various	1	13	11	12
Total regulatory assets		$ 144	$ 524	$ 216	$ 594
Regulatory liabilities:					
Asset retirement removal costs [7]	[4]	$ —	$ 692	$ —	$ 637
Asset retirement obligations [7]	[4]	—	39	—	36
Power cost adjustment mechanism	1 year	6	—	—	10
Other	Various	6	34	6	37
Total regulatory liabilities		$ 12 [8]	$ 765	$ 6 [8]	$ 720

(1) As of December 31, 2012.
(2) Does not include a return on investment.
(3) Recovery expected over the average service life of employees. For additional information, see Note 2, Summary of Significant Accounting Policies.
(4) Recovery expected over the estimated lives of the assets.
(5) Recovery period not yet determined.
(6) Of the total other unamortized regulatory asset balances, a return is recorded on $15 million and $21 million as of December 31, 2012 and 2011, respectively.
(7) Included in rate base for ratemaking purposes.
(8) Included in Accrued expenses and other current liabilities on the consolidated balance sheets.

As of December 31, 2012, PGE had regulatory assets of $31 million earning a return on investment at the following rates: (i) $18 million at PGE's cost of debt of 6.065%; (ii) $10 million earning a return by inclusion in rate base; and (iii) $3 million at the approved rate for deferred accounts under amortization, ranging from 1.47% to 2.24%, depending on the year of approval.

Price risk management represents the difference between the net unrealized losses recognized on derivative instruments related to price risk management activities and their realization and subsequent recovery in customer prices. For further information regarding assets and liabilities from price risk management activities, see Note 5, Price Risk Management.

Pension and other postretirement plans represents unrecognized components of the benefit plans' funded status, which are recoverable in customer prices when recognized in net periodic benefit cost. For further information, see Note 10, Employee Benefits.

Deferred income taxes represents income tax benefits resulting from property-related timing differences that previously flowed to customers and will be included in customer prices when the temporary differences reverse. For further information, see Note 11, Income Taxes.

Deferred broker settlements consist of transactions that have been financially settled by clearing brokers prior to the contract delivery date. These gains and losses are deferred for future recovery in customer prices during the corresponding contract settlement month.

Debt issuance costs represents unrecognized debt issuance costs related to debt instruments retired prior to the stipulated maturity date.

Deferred capital projects represents costs related to four capital projects that were deferred for future accounting treatment pursuant to the Company's last general rate case. The recovery of these project costs in future customer prices is subject to a regulated earnings test and approval by the OPUC.

Asset retirement removal costs represent the costs that do not qualify as AROs and are a component of depreciation expense allowed in customer prices. Such costs are recorded as a regulatory liability as they are collected in prices, and are reduced by actual removal costs incurred.

Asset retirement obligations represent the difference in the timing of recognition of (i) the amounts recognized for depreciation expense of the asset retirement costs and accretion of the ARO, and (ii) the amount recovered in customer prices.

Power cost adjustment mechanism represents the estimated refund to customers recorded pursuant to this regulatory mechanism. For further information, see "*Power Cost Adjustment Mechanism*" in the Regulatory Accounting section in Note 2, Summary of Significant Accounting Policies.

NOTE 7: ASSET RETIREMENT OBLIGATIONS

AROs consist of the following (in millions):

	As of December 31,	
	2012	**2011**
Trojan decommissioning activities	$ 42	$ 37
Utility plant	39	38
Non-utility property	13	12
Asset retirement obligations	$ 94	$ 87

Trojan decommissioning activities represents the present value of future decommissioning expenditures for the plant, which ceased operation in 1993. The remaining decommissioning activities primarily consist of the long-term operation and decommissioning of the Independent Spent Fuel Storage Installation (ISFSI), an interim dry storage facility that is licensed by the Nuclear Regulatory Commission. The ISFSI is to house the spent nuclear fuel at the former plant site until an off-site storage facility is available. Decommissioning of the ISFSI and final site restoration activities will begin once shipment of all the spent fuel to a U.S. Department of Energy (USDOE) facility is complete.

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

A trial before the U.S. Court of Federal Claims commenced in the fourth quarter of 2011 and concluded in early 2012. On November 30, 2012, the United States Court of Federal Claims issued a judgment awarding certain damages to the Plaintiffs. The judgment does not state the precise amount of the damages award, but directs the parties to consult and propose by the end of February 2013 a final amount for the Plaintiffs' recovery that is based on certain adjustments specified in the court's ruling. PGE estimates that the total amount of the award, as calculated pursuant to the judgment, will range from approximately $65 million to $75 million. Any award amount would be allocated among the Plaintiffs. The judgment includes damages incurred through 2009. The Plaintiffs may seek damages for subsequent years through a separate legal proceeding.

The USDOE will likely appeal, which will defer any damage payment indefinitely. The Trojan ARO will not be impacted by the outcome of this case as such potential recovery is for past decommissioning costs and the ARO reflects only future decommissioning expenditures. Any proceeds received related to this legal matter would flow to the benefit of customers to offset amounts previously collected from customers in relation to Trojan decommissioning activities.

Utility plant represents AROs that have been recognized for the Company's thermal and wind generation sites, distribution and transmission assets where disposal is governed by environmental regulation, as well as the Bull Run hydro project. Decommissioning work was substantially completed at Bull Run in 2012.

During 2011, an updated decommissioning study for PGE's Boardman coal-fired plant was completed, which included the assumption that Boardman's coal-fired operations cease in 2020 rather than 2040. As a result of the study, PGE increased its ARO related to Boardman by approximately $20 million, with a corresponding increase in the cost basis of the plant, included in Electric utility plant, net on the consolidated balance sheet. Such transaction is non-cash and is excluded from investing activities in the consolidated statement cash flows for the year ended December 31, 2011.

Non-utility property primarily represents ARO's which have been recognized for portions of unregulated properties leased to third parties.

The following is a summary of the changes in the Company's AROs (in millions):

	Years Ended December 31,		
	2012	2011	2010
Balance as of beginning of year	$ 87	$ 64	$ 63
Liabilities incurred	—	1	1
Liabilities settled	(3)	(4)	(3)
Accretion expense	6	4	4
Revisions in estimated cash flows	4	22	(1)
Balance as of end of year	$ 94	$ 87	$ 64

Pursuant to regulation, the amortization of utility plant AROs is included in depreciation expense and in customer prices. Any differences in the timing of recognition of costs for financial reporting and ratemaking purposes are deferred as a regulatory asset or regulatory liability. Recovery of Trojan decommissioning costs is included in

PGE's retail prices, currently at approximately $4 million annually, with an equal amount recorded in Depreciation and amortization expense.

PGE maintains a separate trust account, Nuclear decommissioning trust in the consolidated balance sheet, for funds collected from customers through prices to cover the cost of Trojan decommissioning activities. See "*Trust Accounts*" in Note 3, Balance Sheet Components, for additional information on the Nuclear decommissioning trust.

The Oak Grove hydro facility and transmission and distribution plant located on public right-of-ways and on certain easements meet the requirements of a legal obligation and will require removal when the plant is no longer in service. An ARO liability is not currently measurable as management believes that these assets will be used in utility operations for the foreseeable future. Removal costs are charged to accumulated asset retirement removal costs, which is included in Regulatory liabilities on PGE's consolidated balance sheets.

NOTE 8: REVOLVING CREDIT FACILITIES

PGE has two unsecured revolving credit facilities, with an aggregate borrowing capacity of $700 million, as follows:

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

Pursuant to the terms of the agreements, both credit facilities may be used for general corporate purposes and as backup for commercial paper borrowings, and also permit the issuance of standby letters of credit. PGE may borrow for one, two, three, or six months at a fixed interest rate established at the time of the borrowing, or at a variable interest rate for any period up to the then remaining term of the applicable credit facility. Both credit facilities contain two, one-year extensions subject to approval by the banks, require annual fees based on PGE's unsecured credit ratings, and contain customary covenants and default provisions, including a requirement that limits consolidated indebtedness, as defined in the agreement, to 65.0% of total capitalization. As of December 31, 2012, PGE was in compliance with this covenant with a 48.9% debt 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 FERC, the Company is authorized to issue short-term debt up to $700 million through February 6, 2014. The authorization provides that if utility assets financed by unsecured debt are divested, then a proportionate share of the unsecured debt must also be divested.

As of December 31, 2012, PGE had no borrowings under the credit facilities, with $17 million of commercial paper outstanding, which is classified as Short-term debt in the consolidated balance sheet, and $67 million of letters of credit issued. As of December 31, 2012, the aggregate unused available credit under the credit facilities was $616 million.

Short-term borrowings under these credit facilities and related interest rates were as follows (dollars in millions):

	Years Ended December 31,		
	2012	2011	2010
Average daily amount of short-term debt outstanding	$ 4	$ 2	$ 9
Weighted daily average interest rate *	0.4%	0.4%	0.4%
Maximum amount outstanding during the year	$ 44	$ 44	$ 51

* Excludes the effect of commitment fees, facility fees and other financing fees.

NOTE 9: LONG-TERM DEBT

Long-term debt consists of the following (in millions):

	As of December 31,	
	2012	2011
First Mortgage Bonds, rates range from 3.46% to 9.31%, with a weighted average rate of 5.84% in 2012 and 5.83% in 2011, due at various dates through 2040	$ 1,515	$ 1,615
Pollution Control Revenue Bonds, 5% rate, due 2033	142	142
Pollution Control Revenue Bonds owned by PGE	(21)	(21)
Unamortized debt discount	—	(1)
Total long-term debt	1,636	1,735
Less: current portion of long-term debt	(100)	(100)
Long-term debt, net of current portion	$ 1,536	$ 1,635

First Mortgage Bonds—In accordance with the terms of the debt agreement, PGE repaid during October 2012 the 5.6675% Series of First Mortgage Bonds in the amount of $100 million. The Indenture securing PGE's outstanding First Mortgage Bonds constitutes a direct first mortgage lien on substantially all regulated utility property, other than expressly excepted property.

Pollution Control Revenue Bonds—PGE has the option to remarket $21 million of Pollution Control Revenue Bonds held by the Company through 2033. At the time of any remarketing, PGE can choose a new interest rate period that could be daily, weekly, or a fixed term. The new interest rate would be based on market conditions at the time of remarketing. The Pollution Control Revenue Bonds could be backed by first mortgage bonds or a bank letter of credit depending on market conditions.

As of December 31, 2012, the future minimum principal payments on long-term debt are as follows (in millions):

Years ending December 31:	
2013	$ 100
2014	—
2015	70
2016	67
2017	58
Thereafter	1,341
	$ 1,636

Interest is payable semi-annually on all long-term debt instruments.

NOTE 10: EMPLOYEE BENEFITS

Pension and Other Postretirement Plans

Defined Benefit Pension Plan—PGE sponsors a non-contributory defined benefit pension plan. The plan has been closed to most new employees since January 31, 2009 and to all new employees since January 1, 2012, with no changes in benefits provided to existing participants.

The assets of the pension plan are held in a trust and are comprised of equity and debt instruments, as well as alternative asset investment vehicles, all of which are recorded at fair value. Pension plan calculations include several assumptions which are reviewed annually and are updated as appropriate, with the measurement date of December 31.

PGE made no contributions to the pension plan in 2012, with contributions of $26 million and $30 million in 2011 and 2010, respectively. No contributions to the pension plan are expected in 2013.

Other Postretirement Benefits—PGE has non-contributory postretirement health and life insurance plans, as well as Health Reimbursement Accounts (HRAs) for its employees (collectively "Other Postretirement Benefits" in the following tables). Employees are covered under a Defined Dollar Medical Benefit Plan which limits PGE's obligation pursuant to the postretirement health plan by establishing a maximum benefit per employee with employees paying the additional cost.

The assets of these plans are held in voluntary employees' beneficiary association trusts and are comprised of money market funds, common stocks, common and collective trust funds, partnerships/joint ventures, and registered investment companies, all of which are recorded at fair value. Postretirement health and life insurance benefit plan calculations include several assumptions which are reviewed annually with PGE's consulting actuaries and trust investment consultants and updated as appropriate, with measurement dates of December 31.

Contributions to the HRAs provide for claims by retirees for qualified medical costs. For bargaining employees, the participants' accounts are credited with 58% of the value of the employee's accumulated sick time as of April 30, 2004, a stated amount per compensable hour worked, plus 100% of their earned time off accumulated at the time of retirement. For active non-bargaining employees, the Company grants a fixed dollar amount that will become available for qualified medical expenses upon their retirement.

Non-Qualified Benefit Plans—The Non-Qualified Benefit Plans (NQBP) in the following tables include obligations for a Supplemental Executive Retirement Plan, and a directors pension plan, both of which were closed to new participants in 1997. The NQBP also include pension make-up benefits for employees that participate in the unfunded Management Deferred Compensation Plan (MDCP). Investments in a non-qualified benefit plan trust, consisting of trust-owned life insurance policies and marketable securities, provide funding for the future requirements of these plans. These trust assets are included in the accompanying tables for informational purposes only and are not considered segregated and restricted under current accounting standards. The investments in marketable securities, consisting of money market, bond, and equity mutual funds, are classified as trading and recorded at fair value. The measurement date for the non-qualified benefit plans is December 31.

Other NQBP—In addition to the non-qualified benefit plans discussed above, PGE provides certain employees and outside directors with deferred compensation plans, whereby participants may defer a portion of their earned compensation. These unfunded plans include the MDCP and the Outside Directors' Deferred Compensation Plan. The Company also provides two retired employees with death benefits through a split dollar life insurance policy which pays a fixed amount to the beneficiary and for which the Company has a security interest for the amount of premiums paid. PGE holds investments in a non-qualified benefit plan trust which are intended to be a funding source for these plans.

Trust assets and plan liabilities related to the NQBP included in PGE's consolidated balance sheets are as follows as of December 31 (in millions):

	2012			2011		
	NQBP	Other NQBP	Total	NQBP	Other NQBP	Total
Non-qualified benefit plan trust	$ 15	$ 17	$ 32	$ 17	$ 19	$ 36
Non-qualified benefit plan liabilities *	25	77	102	25	76	101

* For the NQBP, excludes the current portion of $2 million in 2012 and 2011, which is classified in Other current liabilities in the consolidated balance sheets.

See "*Trust Accounts*" in Note 3, Balance Sheet Components, for information on the Non-qualified benefit plan trust.

Investment Policy and Asset Allocation—The Board of Directors of PGE appoints an Investment Committee, which is comprised of officers of the Company. In addition, the Board also establishes the Company's asset allocation. The Investment Committee is then responsible for implementation and oversight of the asset allocation. The Company's investment policy for its pension and other postretirement plans is to balance risk and return through a diversified portfolio of equity securities, fixed income securities and other alternative investments. The commitments to each class are controlled by an asset deployment and cash management strategy that takes profits from asset classes whose allocations have shifted above their target ranges to fund benefit payments and investments in asset classes whose allocations have shifted below their target ranges.

The asset allocations for the plans, and the target allocation, are as follows:

	As of December 31,			
	2012		2011	
	Actual	Target *	Actual	Target *
Defined Benefit Pension Plan:				
Equity securities	68%	67%	68%	67%
Debt securities	32	33	32	33
Total	100%	100%	100%	100%
Other Postretirement Benefit Plans:				
Equity securities	63%	72%	61%	72%
Debt securities	37	28	39	28
Total	100%	100%	100%	100%
Non-Qualified Benefits Plans:				
Equity securities	17%	17%	30%	23%
Debt securities	6	10	7	14
Insurance contracts	77	73	63	63
Total	100%	100%	100%	100%

* The Target for the Defined Benefit Plan represents the mid-point of the investment target range. Due to the nature of the investment vehicles in both the Other Postretirement Benefit Plans and the Non-Qualified Benefit Plans, these Targets are the weighted average of the mid-point of the respective investment target ranges approved by the Investment Committee. Due to the method used to calculate the weighted average Targets for the Other Postretirement Benefit Plans and Non-Qualified Benefit Plans, reported percentages are affected by the fair market values of the investments within the pools.

The Company's overall investment strategy is to meet the goals and objectives of the individual plans through a wide diversification of asset types, fund strategies, and fund managers. Equity securities primarily include investments across the capitalization ranges and style biases, both domestically and internationally. Fixed income securities include, but are not limited to, corporate bonds of companies from diversified industries, mortgage-backed securities, and U.S. Treasuries. Other types of investments include investments in hedge funds and private equity funds that follow several different strategies.

The fair values of the Company's pension plan assets and other postretirement benefit plan assets by asset category are as follows (in millions):

	As of December 31, 2012			
	Level 1	Level 2	Level 3	Total
Defined Benefit Pension Plan assets:				
Money market funds	$ —	$ 1	$ —	$ 1
Equity securities:				
Domestic	150	15	—	165
International	166	—	—	166
Debt securities:				
Domestic government and corporate credit	—	165	—	165
Corporate credit	8	—	—	8
Private equity funds	—	—	32	32
	$ 324	$ 181	$ 32	$ 537
Other Postretirement Benefit Plans assets:				
Money market funds	$ —	$ 8	$ —	$ 8
Equity securities:				
Domestic	8	1	—	9
International	8	—	—	8
Debt securities—Domestic government	3	—	—	3
	$ 19	$ 9	$ —	$ 28

	As of December 31, 2011			
	Level 1	Level 2	Level 3	Total
Defined Benefit Pension Plan assets:				
Money market funds	$ —	$ 3	$ —	$ 3
Equity securities:				
Domestic	151	12	—	163
International	54	51	—	105
Debt securities:				
Domestic government and corporate credit	—	78	—	78
Corporate credit	76	—	—	76
Private equity funds	—	—	32	32
Alternative investments	—	—	30	30
	$ 281	$ 144	$ 62	$ 487
Other Postretirement Benefit Plans assets:				
Money market funds	$ —	$ 7	$ —	$ 7
Equity securities:				
Domestic	12	1	—	13
International	2	2	—	4
Debt securities—Domestic government	3	—	—	3
	$ 17	$ 10	$ —	$ 27

An overview of the identification of Level 1, 2, and 3 financial instruments is provided in Note 4, Fair Value of Financial Instruments. The following methods are used in valuation of each asset class of investments held in the pension and other postretirement benefit plan trusts.

Money market funds—PGE invests in money market funds that seek to maintain a stable net asset value. These funds invest in high-quality, short-term, diversified money market instruments, short term treasury bills, federal agency securities, certificates of deposit, and commercial paper. Money market funds held in the trusts are classified as Level 2 instruments as they are traded in an active market of similar securities but are not directly valued using quoted prices.

Equity securities—Equity mutual fund and common stock securities are primarily classified as Level 1 securities based on unadjusted prices in an active market. Principal markets for equity prices include published exchanges such as NASDAQ and NYSE. Certain mutual fund assets included in commingled trusts or separately managed accounts are classified as Level 2 securities due to pricing inputs that are not directly or indirectly observable in the marketplace.

Debt securities—PGE invests in highly-liquid United States treasury and corporate credit mutual fund securities to support the investment objectives of the trusts. These securities are classified as Level 1 instruments due to the highly observable nature of pricing in an active market.

Fair values for Level 2 debt securities, including municipal debt and corporate credit securities, mortgage-backed securities and asset-backed securities are determined by evaluating pricing data, such as broker quotes, for similar securities adjusted for observable differences. Significant inputs used in valuation models generally include benchmark yield and issuer spreads. The external credit rating, coupon rate, and maturity of each security are considered in the valuation if applicable.

Private equity funds—PGE invests in a combination of primary and secondary fund-of-funds which hold ownership positions in privately held companies across the major domestic and international private equity sectors, including but not limited to, venture capital, buyout and special situations. Private equity investments are classified as Level 3 securities due to fund valuation methodologies that utilize discounted cash flow, market comparable and limited secondary market pricing to develop estimates of fund valuation. PGE valuation of individual fund performance compares stated fund performance against published benchmarks.

Alternative investments—Investments in a portable alpha strategy are comprised of long positions in S&P 500 futures contracts and a hedge fund-of-funds comprised of diversified group, by sector and market capitalization of long only, short only and/or both long/short equity hedge funds. Valuation of hedge funds included within this vehicle is provided by fund managers using unobservable internally modeled inputs. PGE performs validation procedures of manager performance by comparing stated performance against published benchmarks. Alternative investments are classified as Level 3 due to lack of observable market inputs and relative illiquidity of the fund.

Changes in the fair value of assets held by the pension plan classified as Level 3 in the fair value hierarchy presented in the table above were as follows for the three years ended December 31, 2012 (in millions):

	Private equity funds	Alternative investments	Total Level 3
Balance as of December 31, 2009	$ 17	$ 23	$ 40
Purchases and sales, net	4	2	6
Realized gain on sales	1	—	1
Unrealized gain on assets	1	3	4
Balance as of December 31, 2010	23	28	51
Purchases	7	—	7
Realized loss on sales	(2)	—	(2)
Unrealized gain on assets	4	2	6
Balance as of December 31, 2011	32	30	62
Purchases and sales, net	(1)	(30)	(31)
Realized gain (loss) on sales	(1)	6	5
Unrealized gain (loss) on assets	2	(6)	(4)
Balance as of December 31, 2012	$ 32	$ —	$ 32

The following tables provide certain information with respect to the Company's defined benefit pension plan, other postretirement benefits, and non-qualified benefit plans as of and for the years ended December 31, 2012 and 2011. Information related to the Other NQBP is not included in the following tables (dollars in millions):

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2012	2011	2012	2011	2012	2011
Benefit obligation:						
As of January 1	$ 634	$ 550	$ 75	$ 79	$ 27	$ 25
Service cost	14	12	2	2	—	—
Interest cost	31	29	3	4	1	1
Participants' contributions	—	—	2	2	—	—
Actuarial loss (gain)	77	69	7	(5)	1	3
Contractual termination benefits	—	—	1	—	—	—
Benefit payments	(28)	(26)	(6)	(7)	(2)	(2)
As of December 31	$ 728	$ 634	$ 84	$ 75	$ 27	$ 27
Fair value of plan assets:						
As of January 1	$ 487	$ 473	$ 27	$ 16	$ 17	$ 19
Actual return on plan assets	78	14	3	—	—	—
Company contributions	—	26	2	16	—	—
Participants' contributions	—	—	2	2	—	—
Benefit payments	(28)	(26)	(6)	(7)	(2)	(2)
As of December 31	$ 537	$ 487	$ 28	$ 27	$ 15	$ 17
Unfunded position as of December 31	$ (191)	$ (147)	$ (56)	$ (48)	$ (12)	$ (10)
Accumulated benefit plan obligation as of December 31	$ 640	$ 566	N/A	N/A	$ 27	$ 27
Classification in consolidated balance sheet:						
Noncurrent asset	$ —	$ —	$ —	$ —	$ 15	$ 17
Current liability	—	—	—	—	(2)	(2)
Noncurrent liability	(191)	(147)	(56)	(48)	(25)	(25)
Net liability	$ (191)	$ (147)	$ (56)	$ (48)	$ (12)	$ (10)

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2012	2011	2012	2011	2012	2011
Amounts included in comprehensive income:						
Net actuarial loss (gain)	$ 40	$ 97	$ 5	$ (4)	$ 2	$ 2
Amortization of net actuarial loss	(17)	(8)	(1)	(1)	(1)	(1)
Amortization of prior service cost	—	(1)	(1)	(1)	—	—
	$ 23	$ 88	$ 3	$ (6)	$ 1	$ 1
Amounts included in AOCL*:						
Net actuarial loss	$ 298	$ 275	$ 18	$ 15	$ 11	$ 10
Prior service cost	1	1	4	4	—	—
	$ 299	$ 276	$ 22	$ 19	$ 11	$ 10
Assumptions used:						
Discount rate for benefit obligation	4.24%	5.00%	2.77% - 4.13%	3.76% - 4.90%	4.24%	5.00%
Discount rate for benefit cost	5.00%	5.47%	3.76% - 4.90%	4.02% - 5.40%	5.00%	5.47%
Weighted average rate of compensation increase for benefit obligation	3.65%	3.71%	4.58%	4.58%	N/A	N/A
Weighted average rate of compensation increase for benefit cost	3.71%	3.80%	4.58%	4.83%	N/A	N/A
Long-term rate of return on plan assets for benefit obligation	8.25%	8.25%	6.50%	7.09%	N/A	N/A
Long-term rate of return on plan assets for benefit cost	8.25%	8.50%	7.09%	6.44%	N/A	N/A

* Amounts included in AOCL related to the Company's defined benefit pension plan and other postretirement benefits are transferred to Regulatory assets due to the future recoverability from retail customers. Accordingly, as of the balance sheet date, such amounts are included in Regulatory assets.

Net periodic benefit cost consists of the following for the years ended December 31 (in millions):

	Defined Benefit Pension Plan			Other Postretirement Benefits			Non-Qualified Benefit Plans		
	2012	2011	2010	2012	2011	2010	2012	2011	2010
Service cost	$ 14	$ 12	$ 11	$ 2	$ 2	$ 2	$ —	$ —	$ —
Interest cost on benefit obligation	31	29	28	3	4	4	1	1	1
Expected return on plan assets	(41)	(42)	(39)	(1)	(1)	(1)	—	—	—
Amortization of prior service cost	—	1	1	1	1	1	—	—	—
Amortization of net actuarial loss	17	8	3	1	1	1	1	1	1
Net periodic benefit cost	$ 21	$ 8	$ 4	$ 6	$ 7	$ 7	$ 2	$ 2	$ 2

PGE estimates that $27 million will be amortized from AOCL into net periodic benefit cost in 2013, consisting of a net actuarial loss of $24 million for pension benefits, $1 million for non-qualified benefits and $1 million for other postretirement benefits, and prior service cost of $1 million for other postretirement benefits.

The following table summarizes the benefits expected to be paid to participants in each of the next five years and in the aggregate for the five years thereafter (in millions):

	Payments Due					
	2013	2014	2015	2016	2017	2018 - 2022
Defined benefit pension plan	$ 32	$ 33	$ 35	$ 37	$ 38	$ 215
Other postretirement benefits	5	5	5	5	5	26
Non-qualified benefit plans	2	2	2	2	2	10
Total	$ 39	$ 40	$ 42	$ 44	$ 45	$ 251

All of the plans develop expected long-term rates of return for the major asset classes using long-term historical returns, with adjustments based on current levels and forecasts of inflation, interest rates, and economic growth. Also included are incremental rates of return provided by investment managers whose returns are expected to be greater than the markets in which they invest.

For measurement purposes, the assumed health care cost trend rates, which can affect amounts reported for the health care plans, were as follows:

- For 2012, 8% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2013, and assumed to decrease 0.5% per year thereafter, reaching 5% in 2019;
- For 2011, 8% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2012 through 2013, and assumed to decrease 0.5% per year thereafter, reaching 5% in 2019; and
- For 2010, 8% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2011 through 2013, and assumed to decrease 0.5% per year thereafter, reaching 5% in 2019.

A one percentage point increase or decrease in the above health care cost assumption would have no material impact on total service or interest cost, or on the postretirement benefit obligation.

401(k) Retirement Savings Plan

PGE sponsors a 401(k) Plan that covers substantially all employees. For eligible employees who are covered by PGE's defined benefit pension plan, the Company matches employee contributions up to 6% of the employee's base pay. For eligible employees who are not covered by PGE's defined benefit pension plan, the Company contributes 5% of the employee's base salary, whether or not the employee contributes to the 401(k) Plan, and also matches employee contributions up to 5% of the employee's base pay.

For bargaining employees, who are subject to the International Brotherhood of Electrical Workers Local 125 agreements, the Company contributes 1% of the employee's base salary, whether or not the employee contributes to the 401(k) Plan.

All contributions are invested in accordance with employees' elections, limited to investment options available under the 401(k) Plan. PGE made contributions to employee accounts of $16 million in each of 2012 and 2011, and $15 million in 2010.

NOTE 11: INCOME TAXES

Income tax expense (benefit) consists of the following (in millions):

	Years Ended December 31,		
	2012	2011	2010
Current:			
Federal	$ 16	$ 2	$ (20)
State and local	1	—	—
	17	2	(20)
Deferred:			
Federal	30	43	61
State and local	17	13	12
	47	56	73
Income tax expense	$ 64	$ 58	$ 53

The significant differences between the U.S. federal statutory rate and PGE's effective tax rate for financial reporting purposes are as follows:

	Years Ended December 31,		
	2012	2011	2010
Federal statutory tax rate	35.0%	35.0%	35.0%
Federal tax credits	(11.8)	(12.7)	(10.4)
State and local taxes, net of federal tax benefit	3.5	2.6	4.4
Adjustment to deferred taxes for change in blended composite state tax rate	2.6	—	—
Flow through depreciation and cost basis differences	2.4	2.1	0.1
Other	(0.6)	1.3	1.2
Effective tax rate	31.1%	28.3%	30.3%

Deferred income tax assets and liabilities consist of the following (in millions):

	As of December 31, 2012	As of December 31, 2011
Deferred income tax assets:		
Employee benefits	$ 162	$ 135
Price risk management	77	145
Tax credits, net of valuation allowance	55	56
Regulatory liabilities	20	22
Tax loss carryforwards	—	1
Total deferred income tax assets	314	359
Deferred income tax liabilities:		
Depreciation and amortization	623	572
Regulatory assets	224	274
Other	4	9
Total deferred income tax liabilities	851	855
Deferred income tax liability, net	$ (537)	$ (496)
Classification of net deferred income taxes:		
Current deferred income tax asset [(1)]	$ 51	$ 33
Noncurrent deferred income tax liability	(588)	(529)
	$ (537)	$ (496)

(1) Included in Other current assets in the consolidated balance sheets.

PGE has federal and state tax credit carryforwards of $41 million and $14 million, respectively, which will expire at various dates from 2014 through 2031.

PGE believes that it is more likely than not that its deferred income tax assets as of December 31, 2012 and 2011 will be realized; accordingly, no valuation allowance has been recorded. During the year ended December 31, 2011, the valuation allowance decreased $2 million as a result of the expiration of unused state credits.

As of December 31, 2012 and 2011, PGE had no unrecognized tax benefits. As of December 31, 2010, the amount of the Company's unrecognized tax benefit was $2 million, including interest, resulting from a gross increase in a position taken in a prior period. During the year ended December 31, 2010, the Company recognized $1 million in interest and no penalties. During 2011, the unrecognized tax benefit of $2 million was recognized as a result of filing for a federal tax accounting method change.

PGE files income tax returns in the U.S. federal jurisdiction, the states of Oregon and Montana, and certain local jurisdictions. The Internal Revenue Service (IRS) is in the process of finalizing an examination of PGE's income tax returns for 2006, 2009, and 2010, for which no material findings have been identified. The Company is not currently under examination by state or local tax authorities.

NOTE 12: STOCK PURCHASE PLANS

Employee Stock Purchase Plan

PGE has an employee stock purchase plan (ESPP), under which a total of 625,000 shares of the Company's common stock may be issued. The ESPP permits all eligible employees to purchase shares of PGE common stock through regular payroll deductions, which are limited to 10% of base pay. Each year, employees may purchase up to a maximum of $25,000 in common stock (based on fair value on the purchase date) or 1,500 shares, whichever is less. There are two six-month offering periods each year, January 1 through June 30 and July 1 through December 31, during which eligible employees may purchase shares of PGE common stock at a price equal to 95% of the fair value of the stock on the purchase date, the last day of the offering period. As of December 31, 2012, there were 478,758 shares available for future issuance pursuant to the ESPP.

Dividend Reinvestment and Direct Stock Purchase Plan

On April 1, 2011, PGE's Dividend Reinvestment and Direct Stock Purchase Plan (DRIP) became effective, under which a total of 2,500,000 shares of the Company's common stock may be issued. Under the DRIP, investors may elect to buy shares of the Company's common stock or elect to reinvest cash dividends in additional shares of the Company's common stock. As of December 31, 2012, there were 2,490,267 shares available for future issuance pursuant to the DRIP.

NOTE 13: STOCK-BASED COMPENSATION EXPENSE

Pursuant to the Portland General Electric Company 2006 Stock Incentive Plan (the Plan), the Company may grant a variety of equity-based awards, including restricted stock units with time-based vesting conditions (Restricted Stock Units) and performance-based vesting conditions (Performance Stock Units) to non-employee directors, officers and certain key employees. Service requirements generally must be met for stock units to vest. For each grant, the number of Stock Units is determined by dividing the specified award amount for each grantee by the closing stock price on the date of grant. A total of 4,687,500 shares of common stock were registered for future issuance under the Plan, of which 3,824,141 shares remain available for future issuance as of December 31, 2012.

Restricted Stock Units vest in either equal installments over a one-year period on the last day of each calendar quarter, over a three-year period on each anniversary of the grant date, or at the end of a three-year period following the grant date.

Performance Stock Units vest if performance goals are met at the end of a three-year performance period; such goals include return on equity and regulated asset base growth measures. Vesting of Performance Stock Units is calculated by multiplying the number of units granted by a performance percentage determined by the Compensation and Human Resources Committee of PGE's Board of Directors. The performance percentage is calculated based on the extent to which the performance goals are met. In accordance with the Plan, however, the committee may disregard or offset the effect of extraordinary, unusual or non-recurring items in determining results relative to these goals. Based on the attainment of the performance goals, the awards can range from zero to 150% of the grant.

Outstanding Restricted and Performance Stock Units provide for the payment of one Dividend Equivalent Right (DER) for each stock unit. DERs represent an amount equal to dividends paid to shareholders on a share of PGE's common stock and vest on the same schedule as the stock units. The DERs are settled in cash (for grants to non-employee directors) or shares of PGE common stock valued either at the closing stock price on the vesting date (for Performance Stock Unit grants) or dividend payment date (for all other grants). The cash from the settlement of the DERs for non-employee directors may be deferred under the terms of the Portland General Electric Company 2006 Outside Directors' Deferred Compensation Plan.

Restricted and Performance Stock Unit activity is summarized in the following table:

	Units	Weighted Average Grant Date Fair Value
Outstanding as of December 31, 2009	422,263	$ 19.82
Granted	191,469	19.18
Forfeited	(45,081)	23.45
Vested	(103,223)	25.78
Outstanding as of December 31, 2010	465,428	17.88
Granted	152,657	23.84
Forfeited	(106,979)	22.35
Vested	(19,702)	23.34
Outstanding as of December 31, 2011	491,404	18.54
Granted	186,495	24.72
Forfeited	(22,947)	18.95
Vested	(214,390)	15.67
Outstanding as of December 31, 2012	440,562	22.54

The number of vested Restricted and Performance Stock Units presented above exceed the number of shares issued for the vesting of restricted and performance stock units on the consolidated statements of equity because, upon vesting, the Company withholds a portion of the vested shares for the payment of income taxes on behalf of the employees. The total value of Restricted and Performance Stock Units vested during the years ended December 31, 2012, 2011, and 2010 was $3 million, $1 million and $3 million, respectively. The weighted average fair value is measured based on the closing price of PGE common stock on the date of grant. PGE recorded $4 million of stock-based compensation expense for the years ended December 31, 2012 and 2011, respectively, and $2 million in 2010, which is included in Administrative and other expense in the consolidated statements of income. Such amounts differ from those reported in the consolidated statements of equity for Stock-based compensation due primarily to the impact from the income tax payments made on behalf of employees. The net impact to equity from the income tax payments, partially offset by the issuance of DERs, resulted in a charge to equity of $1 million in 2012, and less than $1 million in each of 2011 and 2010, which is not included in Administrative and other expenses in the consolidated statements of income.

As of December 31, 2012, unrecognized stock-based compensation expense was $4 million, of which approximately $3 million and $1 million is expected to be expensed in 2013 and 2014, respectively. Stock-based compensation expense was calculated assuming the attainment of performance goals that would allow the vesting of 111.6%, 115.0%, and 114.8% of awarded Performance Stock Units for 2012, 2011, and 2010, respectively, with an estimated 5% forfeiture rate. No stock-based compensation costs have been capitalized and the Plan had no material impact on cash flows for the years ended December 31, 2012, 2011, or 2010.

NOTE 14: EARNINGS PER SHARE

Basic earnings per share is computed based on the weighted average number of common shares outstanding during the year. Diluted earnings per share is computed using the weighted average number of common shares outstanding and the effect of dilutive potential common shares outstanding during the year using the treasury stock method. Dilutive potential common shares consist of Restricted Stock Units, employee stock purchase plan shares and those Performance Stock Units and related DERs associated with the three-year performance period ended December 31, 2012, as such performance criteria was attained. Unvested Performance Stock Units and related DERs are not included in the computation of dilutive securities because vesting of these instruments is dependent upon the attainment of required criteria over three-year performance periods. For additional information on Performance Stock Units and DERs, see Note 13, Stock-Based Compensation Expense.

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

	Years Ended December 31,		
	2012	**2011**	**2010**
Numerator (in millions):			
Net income attributable to Portland General Electric Company common shareholders	$ 141	$ 147	$ 125
Denominator (in thousands):			
Weighted average common shares outstanding—basic	75,498	75,333	75,275
Dilutive effect of unvested restricted stock units and employee stock purchase plan shares	149	17	16
Weighted average common shares outstanding—diluted	75,647	75,350	75,291
Earnings per share—basic and diluted	**$ 1.87**	**$ 1.95**	**$ 1.66**

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 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.

NOTE 15: COMMITMENTS AND GUARANTEES

Commitments

As of December 31, 2012, PGE's future minimum payments pursuant to purchase obligations for the following five years and thereafter are as follows (in millions):

	Payments Due						
	2013	2014	2015	2016	2017	Thereafter	Total
Capital and other purchase commitments	$ 81	$ 10	$ 11	$ 9	$ 2	$ 72	$ 185
Purchased power and fuel:							
Electricity purchases	154	83	82	64	36	440	859
Capacity contracts	21	21	20	19	—	—	81
Public Utility Districts	8	8	8	7	5	25	61
Natural gas	55	26	21	12	10	6	130
Coal and transportation	22	9	—	—	—	—	31
Operating leases	9	9	9	10	11	186	234
Total	$ 350	$ 166	$ 151	$ 121	$ 64	$ 729	$ 1,581

Capital and other purchase commitments—Certain commitments have been made for capital and other purchases for 2013 and beyond. Such commitments include those related to hydro licenses, upgrades to production, distribution and transmission facilities, decommissioning activities, information systems, and system maintenance work. Termination of these agreements could result in cancellation charges.

Electricity purchases and Capacity contracts—PGE has power purchase contracts with counterparties, which expire at varying dates through 2037, and power capacity contracts through 2016. As of December 31, 2012, PGE has power sale contracts with counterparties of approximately $7 million in 2013 and $2 million in 2014.

Public Utility Districts—PGE has long-term power purchase contracts with certain public utility districts in the state of Washington and with the City of Portland, Oregon. The Company is required to pay its proportionate share of the operating and debt service costs of the hydroelectric projects whether or not they are operable. The future minimum payments for the Public Utility Districts in the preceding table reflect the principal payment only and do not include interest, operation, or maintenance expenses. Selected information regarding these projects is summarized as follows (dollars in millions):

	Revenue Bonds as of December 31, 2012	PGE Share		Contract Expiration	PGE Cost, including Debt Service		
		Output	Capacity (in MW)		2012	2011	2010
Priest Rapids and Wanapum	$ 928	9.0%	181	2052	$ 14	$ 14	$ 10
Wells	238	19.4	159	2018	10	10	7
Portland Hydro	9	100.0	36	2017	4	4	4

Under contracts with the public utility districts, PGE has acquired a percentage of the output (Allocation) of Priest Rapids and Wanapum and Wells. The contracts provide that, should any other purchaser of output default on payments as a result of bankruptcy or insolvency, PGE would be allocated a pro rata share of the output and operating and debt service costs of the defaulting purchaser. For Wells, PGE would be allocated up to a cumulative maximum of 25% of the defaulting purchaser's percentage Allocation. For Priest Rapids and Wanapum, PGE would be allocated up to a cumulative maximum that would not adversely affect the tax exempt status of any outstanding debt.

Natural gas—PGE has agreements for the purchase and transportation of natural gas from domestic and Canadian sources for its natural gas-fired generating facilities. The Company also has a natural gas storage agreement, which expires in April 2017, for the purpose of fueling the Company's Port Westward and Beaver generating plants.

Coal and transportation—PGE has coal and related rail transportation agreements with take-or-pay provisions related to Boardman, which expire at various dates through 2014.

Operating leases—PGE has various operating leases associated with its headquarters and certain of its production, transmission, and support facilities. The majority of the future minimum operating lease payments presented in the table above consist of (i) the corporate headquarters lease, which expires in 2018, but includes renewal period options through 2043, and (ii) the Port of St. Helens land lease, where PGE's Beaver and Port Westward generating plants operate, which expires in 2096. Rent expense was $10 million in 2012 and $9 million in 2011 and 2010.

The future minimum operating lease payments presented is net of sublease income of: $3 million in 2013, 2014 and 2015; $2 million in 2016; and $1 million in 2017. Sublease income was $3 million in each of 2012, 2011, and 2010.

Guarantees

PGE entered into a sale transaction in 1985 in which it sold an undivided 15% interest in Boardman and a 10.714% undivided interest in the Pacific Northwest Intertie (Intertie) transmission line (jointly the Boardman Assets) to an unrelated third party (Purchaser). The Purchaser leased the Boardman Assets to a lessee (Lessee) unrelated to PGE or the Purchaser. Concurrently, PGE assigned to the Lessee certain agreements for the sale of power and transmission services from Boardman and the Intertie (P&T Agreements) to a regulated electric utility (Utility) unrelated to PGE, the Purchaser, or the Lessee. The payments by the Utility under the P&T Agreements exceed the payments to be made by the Lessee to the Purchaser under the lease. In exchange for PGE undertaking certain obligations of the Lessee under the lease, the Lessee reassigned to PGE certain rights, including the excess payments, under the P&T Agreements. However, in the event that the Utility defaults on the payments it owes under the P&T Agreements, PGE may be required to pay the damages owed by the Lessee to the Purchaser under the lease. Assuming no recovery from the Utility and no reduction in damages from mitigating sales or leases related to the Boardman Assets and P&T Agreements, the maximum amount that would be owed by PGE in 2013 is approximately $47 million. Management believes that circumstances that could result in such amount, or any lesser amount, being owed by the Company are remote. The P&T Agreements expire on December 31, 2013, and PGE's obligation to pay damages owed by the Lessee to the Purchaser under the lease will terminate.

PGE enters into financial agreements and power and natural gas purchase and sale agreements that include indemnification provisions relating to certain claims or liabilities that may arise relating to the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnifications cannot be reasonably estimated. PGE periodically evaluates the likelihood of incurring costs under such indemnities based on the Company's historical experience and the evaluation of the specific indemnities. As of December 31, 2012, 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 consolidated balance sheets with respect to these indemnities.

NOTE 16: VARIABLE INTEREST ENTITIES

PGE has determined that it is the primary beneficiary of three VIEs and, therefore, consolidates the VIEs within the Company's 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. The Company is the Managing Member and a financial institution is the Investor Member in each of the Limited Liability Companies (LLCs), holding equity interests of less than 1% and more than 99%, respectively, in each entity. PGE has determined that its interests in these VIEs contain the obligation to absorb the variability of the entities that could potentially be significant to the VIEs, and the Company has the power to direct the activities that most significantly affect the entities' economic performance.

Determining whether PGE is the primary beneficiary of a VIE is complex, subjective and requires the use of judgments and assumptions. Significant judgments and assumptions made by PGE in determining it is the primary beneficiary of these LLCs include the following: (i) PGE has the experience 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.

During 2010, an impairment loss of $4 million was recognized on the photovoltaic solar power facilities held by one of the LLCs and classified in Depreciation and amortization expense in PGE's consolidated statements of income. Based on PGE's intent to ultimately acquire 100% of the LLC and the fact that the capitalized cost of the photovoltaic solar power facilities exceeded the undiscounted cash flows of the respective facilities over its estimated useful lives, an impairment analysis was performed. The impairment loss was equal to the excess of the carrying amounts over the estimated fair value of the photovoltaic solar power facilities. Estimated fair value was determined using the discounted cash flow method, assuming a discount rate (after taxes) of approximately 7%, which is PGE's allowed rate of return, and estimated useful lives of 20 years. The new cost basis of the photovoltaic solar power facilities is amortized over their remaining estimated useful lives. The valuation technique used to measure fair value of the photovoltaic solar power facilities at the impairment date is considered Level 3 in the fair value hierarchy, as described in Note 4, Fair Value of Financial Instruments.

As noted above, PGE has consolidated the VIEs even though it has less than a 1% ownership interest in the LLCs. The participating members are allocated their proportionate share of the LLCs net losses based on the respective members' ownership percent. Accordingly, the majority of the impairment losses are attributable to the noncontrolling interests through the Net losses attributable to noncontrolling interests in PGE's consolidated statements of income for the year ended December 31, 2010.

Included in PGE's consolidated balance sheets as of December 31, 2012 and 2011 are LLC net assets of $6 million consisting of Cash and cash equivalents of $1 million and Electric utility plant, net of $5 million. These assets can only be used to settle the obligations of the consolidated VIEs and their creditors have no recourse to the general credit of PGE.

NOTE 17: JOINTLY-OWNED PLANT

PGE has interests in three jointly-owned generating facilities. Under the joint operating agreements, each participating owner is responsible for financing its share of construction, operating and leasing costs. PGE's proportionate share of direct operating and maintenance expenses of the facilities is included in the corresponding operating and maintenance expense categories in the consolidated statements of income.

As of December 31, 2012, PGE had the following investments in jointly-owned plant (dollars in millions):

	PGE Share	In-service Date	Plant In-service	Accumulated Depreciation*	Construction Work In Progress
Boardman	65.00%	1980	$ 479	$ 308	$ 8
Colstrip	20.00	1986	507	328	3
Pelton/Round Butte	66.67	1958 / 1964	215	48	5
Total			$ 1,201	$ 684	$ 16

* Excludes asset retirement obligations and accumulated asset retirement removal costs.

NOTE 18: CONTINGENCIES

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

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

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

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

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

Trojan Investment Recovery

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

Numerous challenges and appeals were subsequently filed in various state courts on the issue of the OPUC's authority under Oregon law to grant recovery of, and a return on, the Trojan investment. In 1998, the Oregon Court of Appeals upheld the OPUC's order authorizing PGE's recovery of the Trojan investment, but held that the OPUC did not have the authority to allow 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 settlement, which was approved by the OPUC, allowed PGE to remove from its balance sheet the remaining investment in Trojan as of September 30, 2000, along with several largely offsetting regulatory liabilities. After offsetting the investment in Trojan with these credits, the remaining Trojan regulatory asset balance of approximately $5 million (after tax) was expensed. As a result of the settlement, PGE's investment in Trojan was no longer included in prices charged to customers, either through a return of or a return on that investment. The Utility Reform Project (URP) did not participate in the settlement and filed a complaint with the OPUC challenging the settlement agreements. In 2002, the OPUC issued an order (2002 Order) denying all of the URP's challenges. In 2007, following several appeals by various parties, the Oregon Court of Appeals issued an opinion that remanded the 2002 Order to the OPUC for reconsideration.

The OPUC then issued an order in 2008 (2008 Order) that required PGE to provide refunds, including interest from September 30, 2000, to customers who received service from the Company during the period from October 1, 2000 to September 30, 2001. The Company recorded a charge of $33.1 million in 2008 related to the refund and accrued additional interest expense on the liability until refunds to customers were completed in the first quarter of 2010. The URP and the plaintiffs in the class actions described below separately appealed the 2008 Order to the Oregon Court of Appeals. On February 6, 2013, the Oregon Court of Appeals issued an opinion that upheld the 2008 Order.

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

In 2006, the Oregon Supreme Court issued a ruling ordering the abatement of the class action proceedings until the OPUC responded to the 2002 Order (described above). The Oregon Supreme Court concluded that the OPUC has primary jurisdiction to determine what, if any, remedy can be offered to PGE customers, through price reductions or refunds, for any amount of return on the Trojan investment that the Company collected in prices.

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

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

Pacific Northwest Refund Proceeding

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

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

In October 2011, the FERC issued an Order on Remand, establishing an evidentiary hearing to determine whether any seller had engaged in unlawful market activity in the Pacific Northwest spot markets during the December 25, 2000 through June 20, 2001 period by violating specific contracts or tariffs, and, if so, whether a direct connection existed between the alleged unlawful conduct and the rate charged under the applicable contract. The FERC held that the *Mobile-Sierra* public interest standard governs challenges to the bilateral contracts at issue in this proceeding, and the strong presumption under *Mobile-Sierra* that the rates charged under each contract are just and reasonable would have to be specifically overcome before a refund could be ordered. The FERC directed the presiding judge, if necessary, to determine a refund methodology and to calculate refunds, but held that a market-wide remedy was not appropriate, given the bilateral contract nature of the Pacific Northwest spot markets. Certain parties claiming refunds filed requests for rehearing of the Order on Remand, contesting, among other things, the applicable refund period reflected in the Order, the use of the *Mobile-Sierra* standard, any restraints in the Order on the type of evidence that could be introduced in the hearing, and the lack of market-wide remedy. The rehearing requests remain pending.

In December 2012, the FERC issued an order granting an interlocutory appeal of the trial judge's ruling on the scope of the remand proceeding. In this order, the FERC held that its Order on Remand was not intended to alter the general state of the law regarding the *Mobile-Sierra* presumption. The FERC also held that the *Mobile-Sierra* presumption could be overcome either by (i) a showing that a respondent had violated a contract or tariff and that the violation had a direct connection to the rate charged under the applicable contract or (ii) a showing that the contract rate at issue imposed an excessive burden or seriously harmed the public interest.

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. Pursuant to the settlement proceedings, the Company received notice of two claims and reached agreements to settle both claims for an immaterial amount. The FERC approved both settlements during 2012.

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

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

Management believes that this matter could result in a loss to the Company in excess of the settlement amounts referenced above. However, 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. Due to these uncertainties, sufficient information is currently not available to determine PGE's liability, if any, or to estimate a range of reasonably possible loss.

EPA Investigation of Portland Harbor

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

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

In March 2012, the LWG submitted a draft FS to the EPA for review and approval. The draft FS, along with the RI, provide the framework for the EPA to determine a clean-up remedy for Portland Harbor that will be documented in a Record of Decision, which the EPA is expected to issue in 2015.

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

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

DEQ Investigation of Downtown Reach

The Oregon Department of Environmental Quality (DEQ) has executed a memorandum of understanding with the EPA to administer and enforce clean-up activities for portions of the Willamette River that are upriver from the Portland Harbor Superfund site (the "Downtown Reach"). In January of 2010, the DEQ issued an order requiring PGE to perform an investigation of certain portions of the Downtown Reach. PGE completed this investigation in December 2011 and entered into a consent order with the DEQ in July 2012 to conduct a feasibility study of alternatives for remedial action for the portions of the Downtown Reach that were included within the scope of PGE's investigation. It is expected that the feasibility study will be completed by the end of 2013.

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

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 2003, the EPA included the Harbor Oil site on the National Priority List as a federal Superfund site. PGE received a Notice from the EPA in 2005, in which the Company was named as one of fourteen PRPs with respect to Harbor Oil. Subsequently, an AOC was signed by the EPA and six other parties, including PGE, to implement an RI/FS at Harbor Oil. In 2011, the final draft of the RI report was submitted to the EPA.

In March 2012, the EPA approved the RI and stated that it intends to recommend no action on the site, based on the conclusions of the risk assessment conducted under the CERCLA. Following a public notice and comment period, the EPA is expected to issue a final Record of Decision in March 2013.

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

Alleged Violation of Environmental Regulations at Colstrip

On July 30, 2012, PGE received a Notice of Intent to Sue for violations of the Clean Air Act (CAA) at Colstrip Steam Electric Station (Notice) from counsel on behalf of the Sierra Club and the Montana Environmental Information Center (MEIC). The Notice was also addressed to the other Colstrip co-owners, including PPL Montana, LLC - the operator of Colstrip. PGE has a 20% ownership interest in Units 3 and 4 of Colstrip. The Notice alleges certain violations of the CAA, including New Source Review, Title V, and opacity requirements, and states that the Sierra Club and MEIC will: i) request a United States District Court to impose injunctive relief and civil penalties; ii) require a beneficial environmental project in the areas affected by the alleged air pollution; and iii) seek reimbursement of Sierra Club's and MEIC's costs of litigation and attorney's fees.

Since July 2012, the Sierra Club and MEIC have amended their Notice three times. The first amendment, contained in a letter dated August 30, 2012, asserts that the Colstrip owners violated the Title V air quality operating permit during portions of 2008 and 2009. The second amendment, contained in a letter dated September 27, 2012, asserts that the owners have violated the CAA by failing to timely submit a complete air quality operating permit application to the Montana Department of Environmental Quality (MDEQ). The third amendment, received in December 2012, does not materially alter the prior assertions. Due to the uncertainties concerning this matter, PGE cannot predict the outcome or determine whether it is reasonably possible that the claims, if asserted, would have a material impact on the Company.

Challenge to AOC Related to Colstrip Wastewater Facilities

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

In September 2012, Earthjustice filed an affidavit pursuant to Montana's Major Facility Siting Act (MFSA) that sought review of the AOC by Montana's Board of Environmental Review (BER), on behalf of environmental groups Sierra Club, the MEIC, and the National Wildlife Federation. In September 2012, the operator of Colstrip filed an election with the BER to have this proceeding conducted in Montana state district court as contemplated by the MFSA. In October 2012, Earthjustice, on behalf of Sierra Club, the MEIC and the National Wildlife Federation, filed with the Montana state district court a petition for a writ of mandamus and a complaint for declaratory relief alleging that the AOC fails to require the necessary actions under the MFSA and the Montana Water Quality Act with respect to groundwater seepage from the wastewater facilities at Colstrip. PGE cannot at this time predict the outcome of this matter or determine whether it is reasonably possible that it would have a material impact on the Company.

Revenue Bonds

In 2008, PGE repurchased $5.8 million of Pollution Control Revenue Bonds Series 1996 (Bonds) issued through the Port of Morrow, Oregon. 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.

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.

Oregon Tax Court Ruling

On September 17, 2012, the Oregon Tax Court issued a ruling contrary to an Oregon Department of Revenue interpretation and a current Oregon administrative rule, regarding the treatment of wholesale electricity sales. The underlying issue is whether electricity should be treated as tangible or intangible property for state income tax apportionment purposes. The Oregon Department of Revenue has appealed the ruling of the Oregon Tax Court to the Oregon Supreme Court. It is uncertain whether the ruling would apply retroactively to all open tax years, which, for PGE, include 2006 through 2012.

If the ruling is upheld, PGE estimates that its income tax liability could increase by as much as $12 million due to the impact of the increased assessment of prior years' liability and an increase in the tax rate at which deferred tax liabilities would be recognized in future years. Due to the uncertainty concerning the resolution of this matter, PGE cannot predict the outcome. The Company may seek regulatory recovery of any incremental tax, although there can be no assurance that such recovery would be granted.

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.

QUARTERLY FINANCIAL DATA

(Unaudited)

	Quarter Ended			
	March 31	June 30	September 30	December 31
	(In millions, except per share amounts)			
2012				
Revenues, net	$ 479	$ 413	$ 450	$ 463
Income from operations	88	61	82	71
Net income	49	26	37	28
Net income attributable to Portland General Electric Company	49	26	38	28
Earnings per share—basic and diluted (1)	0.65	0.34	0.50	0.38
2011				
Revenues, net	$ 484	$ 411	$ 439	$ 479
Income from operations	115	57	68	69
Net income	69	22	27	29
Net income attributable to Portland General Electric Company	69	22	27	29
Earnings per share—basic and diluted (1)	0.92	0.29	0.36	0.38

(1) Earnings per share are calculated independently for each period presented. Accordingly, the sum of the quarterly earnings per share amounts may not equal the total for the year.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

ITEM 9A. CONTROLS AND PROCEDURES.

(a) Disclosure Controls and Procedures

Management of the Company, under the supervision and with the participation of the Chief Executive Officer and the Chief Financial Officer, has evaluated the effectiveness of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of the end of the period covered by this report pursuant to Rule 13a-15(b) under the Exchange Act. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of such period, the Company's disclosure controls and procedures are effective.

(b) Management's Annual Report on Internal Control over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act). The Company's internal control over financial reporting is a process designed by, or under the supervision of, the Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America.

Management of the Company, under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the Company's internal control over financial reporting as of the end of the period covered by this report pursuant to Rule 13a-15(c) under the Exchange Act. Management's assessment was based on the framework established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management has concluded that, as of December 31, 2012, the Company's internal control over financial reporting is effective.

The Company's internal control over financial reporting, as of December 31, 2012, has been audited by Deloitte & Touche LLP, the independent registered public accounting firm who audits the Company's consolidated financial statements, as stated in their report included in Item 8.—"Financial Statements and Supplementary Data," which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting, as of December 31, 2012.

(c) Changes in Internal Control over Financial Reporting

There have not been any changes in the Company's internal control over financial reporting during the fourth quarter of 2012 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION.

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

The information required by Item 10 is incorporated herein by reference to the relevant information under the captions "Section 16(a) Beneficial Ownership Reporting Compliance," "Corporate Governance," "Proposal 1: Election of Directors," and "Executive Officers" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on May 22, 2013.

ITEM 11. EXECUTIVE COMPENSATION.

The information required by Item 11 is incorporated herein by reference to the relevant information under the captions "Corporate Governance—Non-Employee Director Compensation," "Corporate Governance—Compensation Committee Interlocks and Insider Participation," "Compensation and Human Resources Committee Report," "Compensation Discussion and Analysis," and "Executive Compensation Tables" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on May 22, 2013.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

The information required by Item 12 is incorporated herein by reference to the relevant information under the captions "Security Ownership of Certain Beneficial Owners, Directors and Executive Officers" and "Equity Compensation Plans," in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on May 22, 2013.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

The information required by Item 13 is incorporated herein by reference to the relevant information under the caption "Corporate Governance" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on May 22, 2013.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The information required by Item 14 is incorporated herein by reference to the relevant information under the captions "Principal Accountant Fees and Services" and "Pre-Approval Policy for Independent Auditor Services" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on May 22, 2013.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

(a) Financial Statements and Schedules

The financial statements are set forth under Item 8 of this Annual Report on Form 10-K. Financial statement schedules have been omitted since they are either not required, not applicable, or the information is otherwise included.

(b) Exhibit Listing

Exhibit Number	Description
(3)	**Articles of Incorporation and Bylaws**
3.1*	Second Amended and Restated Articles of Incorporation of Portland General Electric Company (Form 10-Q filed August 3, 2009, Exhibit 3.1).
3.2*	Ninth Amended and Restated Bylaws of Portland General Electric Company (Form 8-K filed October 27, 2011, Exhibit 3.1).
(4)	**Instruments defining the rights of security holders, including indentures**
4.1*	Portland General Electric Company Indenture of Mortgage and Deed of Trust dated July 1, 1945 (Form 8, Amendment No. 1 dated June 14, 1965) (File No. 001-05532-99).
4.2*	Fortieth Supplemental Indenture dated October 1, 1990 (Form 10-K for the year ended December 31, 1990, Exhibit 4) (File No. 001-05532-99).
4.3*	Fifty-sixth Supplemental Indenture dated May 1, 2006 (Form 8-K filed May 25, 2006, Exhibit 4.1) (File No. 001-05532-99).
4.4*	Fifty-seventh Supplemental Indenture dated December 1, 2006 (Form 8-K filed December 22, 2006, Exhibit 4.1) (File No. 001-05532-99).
4.5*	Fifty-eighth Supplemental Indenture dated April 1, 2007 (Form 8-K filed April 12, 2007, Exhibit 4.1) (File No. 001-05532-99).
4.6*	Fifty-ninth Supplemental Indenture dated October 1, 2007 (Form 8-K filed October 5, 2007, Exhibit 4.1) (File No. 001-05532-99).
4.7*	Sixtieth Supplemental Indenture dated April 1, 2008 (Form 8-K filed April 17, 2008, Exhibit 4.1).
4.8*	Sixty-first Supplemental Indenture dated January 15, 2009 (Form 8-K filed January 16, 2009, Exhibit 4.1).
4.9*	Sixty-second Supplemental Indenture dated April 1, 2009 (Form 8-K filed April 16, 2009, Exhibit 4.1).
4.10*	Sixty-third Supplemental Indenture dated November 1, 2009 (Form 8-K filed November 4, 2009, Exhibit 4.1).
(10)	**Material Contracts**
10.1	Credit Agreement dated November 14, 2012, between Portland General Electric Company, Wells Fargo Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A. and U.S. Bank National Association, as Co-Syndication Agents, and a group of lenders.
10.2*	Credit Agreement dated December 8, 2011, between Portland General Electric Company, Bank of America, N.A., as Administrative Agent, Barclays Capital, as Syndication Agent, and a group of lenders (Form 10-K filed February 24, 2012, Exhibit 10.3).
10.3	First Amendment dated April 10, 2012 to Credit Agreement dated December 8, 2011, between Portland General Electric Company, Bank of America, N.A., as Administrative Agent, and a group of lenders.
10.4	Second Amendment dated October 31, 2012 to Credit Agreement dated December 8, 2011, between Portland General Electric Company, Bank of America, N.A., as Administrative Agent, and a group of lenders.
10.5	Third Amendment dated January 7, 2013 to Credit Agreement dated December 8, 2011, between Portland General Electric Company, Bank of America, N.A., as Administrative Agent, and a group of lenders.

Exhibit Number	Description
Exhibits 10.6 through 10.17 were filed in connection with the Company's 1985 Boardman/Intertie Sale:	
10.6*	Long-term Power Sale Agreement dated November 5, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 001-05532-99).
10.7*	Long-term Transmission Service Agreement dated November 5, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 001-05532-99).
10.8*	Participation Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 001-05532-99).
10.9*	Lease Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 001-05532-99).
10.10*	PGE-Lessee Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 001-05532-99).
10.11*	Asset Sales Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 001-05532-99).
10.12*	Bargain and Sale Deed, Bill of Sale, and Grant of Easements and Licenses dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 001-05532-99).
10.13*	Supplemental Bill of Sale dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 001-05532-99).
10.14*	Trust Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 001-05532-99).
10.15*	Tax Indemnification Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 001-05532-99).
10.16*	Trust Indenture, Mortgage and Security Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 001-05532-99).
10.17*	Restated and Amended Trust Indenture, Mortgage and Security Agreement dated February 27, 1986 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 001-05532-99).
10.18*	Portland General Electric Company Severance Pay Plan for Executive Employees dated June 15, 2005 (Form 8-K filed June 20, 2005, Exhibit 10.1) (File No. 001-05532-99). +
10.19*	Portland General Electric Company Outplacement Assistance Plan dated June 15, 2005 (Form 8-K filed June 20, 2005, Exhibit 10.2) (File No. 001-05532-99). +
10.20*	Portland General Electric Company 2005 Management Deferred Compensation Plan dated January 1, 2005 (Form 10-K filed March 11, 2005, Exhibit 10.18) (File No. 001-05532-99). +
10.21*	Portland General Electric Company Management Deferred Compensation Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.1) (File No. 001-05532-99). +
10.22*	Portland General Electric Company Supplemental Executive Retirement Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.2) (File No. 001-05532-99). +
10.23*	Portland General Electric Company Senior Officers' Life Insurance Benefit Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.3) (File No. 001-05532-99). +
10.24*	Portland General Electric Company Umbrella Trust for Management dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.4) (File No. 001-05532-99). +
10.25*	Portland General Electric Company 2006 Stock Incentive Plan, as amended (Form 10-K filed February 27, 2008, Exhibit 10.23). +

Exhibit Number	Description
10.26*	Portland General Electric Company 2006 Annual Cash Incentive Master Plan (Form 8-K filed March 17, 2006, Exhibit 10.1) (File No. 001-05532-99). +
10.27*	Portland General Electric Company 2006 Outside Directors' Deferred Compensation Plan (Form 8-K filed May 17, 2006, Exhibit 10.1) (File No. 001-05532-99). +
10.28*	Portland General Electric Company 2008 Annual Cash Incentive Master Plan for Executive Officers (Form 8-K filed February 26, 2008, Exhibit 10.1). +
10.29*	Form of Portland General Electric Company Agreement Concerning Indemnification and Related Matters (Form 8-K filed December 24, 2009, Exhibit 10.1). +
10.30*	Form of Portland General Electric Company Agreement Concerning Indemnification and Related Matters for Officers and Key Employees (Form 8-K filed February 19, 2010, Exhibit 10.1). +
10.31*	Form of Directors' Restricted Stock Unit Agreement (Form 8-K filed July 14, 2006, Exhibit 10.1) (File No. 001-05532-99). +
10.32*	Form of Officers' and Key Employees' Performance Stock Unit Agreement (Form 10-Q filed May 3, 2012, Exhibit 10.1). +
10.33*	Employment Agreement dated and effective May 6, 2008 between Stephen M. Quennoz and Portland General Electric Company (Form 10-Q filed May 7, 2008, Exhibit 10.3). +
(12)	**Statements Re Computation of Ratios**
12.1	Computation of Ratio of Earnings to Fixed Charges.
(23)	**Consents of Experts and Counsel**
23.1	Consent of Independent Registered Public Accounting Firm Deloitte & Touche LLP.
(31)	**Rule 13a-14(a)/15d-14(a) Certifications**
31.1	Certification of Chief Executive Officer.
31.2	Certification of Chief Financial Officer.
(32)	**Section 1350 Certifications**
32.1	Certifications of Chief Executive Officer and Chief Financial Officer.
(101)	**Interactive Data File**
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.

* Incorporated by reference as indicated.

\+ Indicates a management contract or compensatory plan or arrangement.

Certain instruments defining the rights of holders of other long-term debt of PGE 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. PGE hereby agrees to furnish a copy of any such instrument to the SEC upon request.

Upon written request to Investor Relations, Portland General Electric Company, 121 S.W. Salmon Street, Portland, Oregon 97204, the Company will furnish shareholders with a copy of any Exhibit upon payment of reasonable fees for reproduction costs incurred in furnishing requested Exhibits.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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 on February 21, 2013.

PORTLAND GENERAL ELECTRIC COMPANY

By: /s/ JAMES J. PIRO
James J. Piro
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated on February 21, 2013.

Signature	Title
/s/ JAMES J. PIRO **James J. Piro**	*President, Chief Executive Officer, and Director* (principal executive officer)
/s/ MARIA M. POPE **Maria M. Pope**	*Senior Vice President, Finance, Chief Financial Officer, and Treasurer* (principal financial and accounting officer)
/s/ JOHN W. BALLANTINE **John W. Ballantine**	*Director*
/s/ RODNEY L. BROWN, JR. **Rodney L. Brown, Jr.**	*Director*
/s/ JACK E. DAVIS **Jack E. Davis**	*Director*
/s/ DAVID A. DIETZLER **David A. Dietzler**	*Director*
/s/ KIRBY A. DYESS **Kirby A. Dyess**	*Director*
/s/ MARK B. GANZ **Mark B. Ganz**	*Director*
/s/ CORBIN A. MCNEILL, JR. **Corbin A. McNeill, Jr.**	*Director*
/s/ NEIL J. NELSON **Neil J. Nelson**	*Director*
/s/ M. LEE PELTON **M. Lee Pelton**	*Director*
/s/ ROBERT T. F. REID **Robert T. F. Reid**	*Director*

PORTLAND GENERAL ELECTRIC COMPANY
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(Dollars in thousands)

	Years Ended December 31,				
	2012	2011	2010	2009	2008
Income from continuing operations before income taxes	$ 205,406	$ 204,714	$ 178,158	$ 131,636	$ 121,825
Total fixed charges	122,851	126,766	131,486	129,948	111,589
Total earnings	$ 328,257	$ 331,480	$ 309,644	$ 261,584	$ 233,414
Fixed charges:					
Interest expense	$ 107,992	$ 110,413	$ 110,240	$ 103,389	$ 90,257
Capitalized interest	3,699	3,059	9,097	11,816	6,184
Interest on certain long-term power contracts	6,643	8,764	8,068	10,038	10,010
Estimated interest factor in rental expense	4,517	4,530	4,081	4,705	5,138
Total fixed charges	$ 122,851	$ 126,766	$ 131,486	$ 129,948	$ 111,589
Ratio of earnings to fixed charges	2.67	2.61	2.35	2.01	2.09

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-170686 on Form S-3 and Registration Statement Nos. 333-135726, 333-142694, and 333-158059 on Form S-8 of our report dated February 21, 2013, relating to the consolidated financial statements of Portland General Electric Company and subsidiaries, and the effectiveness of Portland General Electric Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of Portland General Electric Company for the year ended December 31, 2012.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 21, 2013

EXHIBIT 31.1

CERTIFICATION

I, James J. Piro, certify that:

1. I have reviewed this Annual Report on Form 10-K 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 periods presented in this report;
4. The registrant's other certifying officer(s) 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(s) 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: February 21, 2013

/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 Annual Report on Form 10-K 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 periods presented in this report;
4. The registrant's other certifying officer(s) 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(s) 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: February 21, 2013

/s/ MARIA M. POPE

Maria M. Pope

Senior Vice President, Finance, Chief Financial Officer, and Treasurer

EXHIBIT 32.1

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 Annual Report on Form 10-K for the year ended December 31, 2012, as filed with the Securities and Exchange Commission on February 22, 2013 pursuant to Section 13(a) of the Securities Exchange Act of 1934 (the "Report"), fully complies with the requirements of that section.

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

/s/ JAMES J. PIRO
James J. Piro
President and
Chief Executive Officer

Date: February 21, 2013

/s/ MARIA M. POPE
Maria M. Pope
Senior Vice President, Finance,
Chief Financial Officer, and
Treasurer

Date: February 21, 2013

2012 Accomplishments

The year was marked by many accomplishments for Portland General Electric. Here are a few of the highlights.

High customer satisfaction

- Top-quartile ranking for residential customers[1]
- Top-decile ranking for general business customers[1]
- No. 2 nationally for large key customers[2]

94 percent

PGE's generating plant availability

13 megawatts

Amount of renewable solar power in PGE's energy portfolio

Salem Smart Power Project

Completed 8,000 square-foot building to house 5 MWs worth of lithium ion batteries and 20 associated inverter systems as part of the Pacific NW Smart Grid Demonstration Project

$141 million

Net income for the year

99.985 percent[3]

Service reliability for PGE customers

$1.7 million

Amount contributed to the community through PGE's employee giving campaign

River Mill Dam

The new innovative Fish Collector provides a 500 cubic-feet-per-second attraction flow, providing juvenile fish passage below the dam

1

Rank for the number of renewable power customers in the nation

Maximo®, Mobile & Scheduling

Implemented this workforce management and scheduling technology in Generation and Transmission & Distribution to improve productivity and efficiency

1. Market Strategies International survey
2. TQS Research, Inc. 2012 survey
3. Institute of Electrical and Electronics Engineers' average service availability index

Corporate Information

Board of Directors

Corbin A. McNeill, Jr.
Chairman of the Board of Directors,
Portland General Electric;
Retired Chairman and
co-Chief Executive Officer
Exelon Corporation

James J. Piro
President and Chief Executive Officer,
Portland General Electric

John W. Ballantine
Retired Executive Vice President and
Chief Risk Management Officer,
First Chicago NBD Corporation

Rodney L. Brown, Jr.
Managing Partner,
Cascadia Law Group PLLC

Jack E. Davis
Retired Chief Executive Officer,
Arizona Public Service Company

David A. Dietzler
Retired Pacific Northwest Partner in
Charge of Audit Practice,
KPMG LLP

Kirby A. Dyess
Principal,
Austin Capital Management LLC

Mark B. Ganz
President and Chief Executive Officer,
Cambia Health Solutions, Inc.

Neil J. Nelson
President and Chief Executive Officer,
Siltronic Corporation

M. Lee Pelton
President,
Emerson College

Robert T. F. Reid
Retired Chair and Corporate Director,
British Columbia Transmission
Corporation

Corporate Officers

James J. Piro
President and Chief Executive Officer

James F. Lobdell
Senior Vice President, Finance,
Chief Financial Officer and Treasurer

William O. Nicholson
Senior Vice President,
Customer Service, Transmission and
Distribution

Maria M. Pope
Senior Vice President, Power Supply
and Operations, and Resource Strategy

Arleen N. Barnett
Vice President, Administration

O. Bruce Carpenter
Vice President, Distribution

Carol A. Dillin
Vice President, Customer Strategies
and Business Development

J. Jeffrey Dudley
Vice President, General Counsel
and Corporate Compliance Officer

Campbell A. Henderson
Vice President, Information Technology
and Chief Information Officer

Stephen M. Quennoz
Vice President, Nuclear and
Power Supply/Generation

W. David Robertson
Vice President, Public Policy

Kristin Stathis
Vice President,
Customer Service Operations

Investor Information

Corporate Headquarters
Portland General Electric Company
121 SW Salmon Street
Portland, OR 97204
503.464.8000
Investors.PortlandGeneral.com

Transfer Agent
American Stock
Transfer & Trust Company
59 Maiden Lane
Plaza Level
New York, NY 10038
866.621.2788

Independent Auditors
Deloitte & Touche LLP
3900 U.S. Bancorp Tower
111 SW Fifth Avenue
Portland, OR 97204
503.222.1341

Form 10-K
A copy of the company's 2012 annual report on Form 10-K will be furnished, without charge, upon written request made to:

William Valach
Director, Investor Relations
121 SW Salmon Street
1WTC0403
Portland, OR 97204

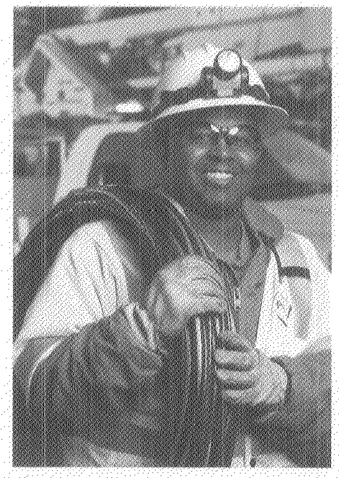
You may also obtain a copy of the Form 10-K by calling Investor Relations at 503.464.8586 or by downloading a copy from the company's website at *Investors.PortlandGeneral.com.*

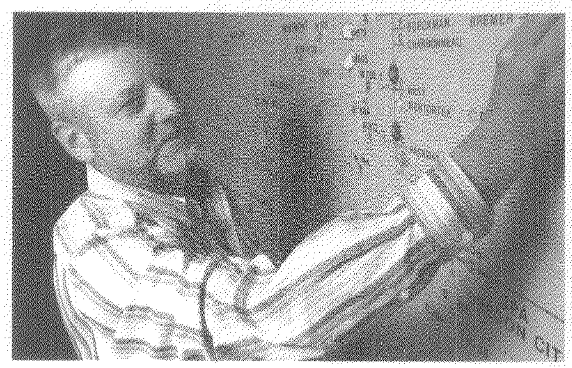
Market Information
Portland General Electric Company common stock trades on the New York Stock Exchange under the ticker symbol POR.

To vote online visit:
Investors.PortlandGeneral.com

Images on cover, from left: *Rob Scott, journeyman lineman; Brian Williams, journeyman lineman; Rhonda Fletcher, driving program safety specialist; Kenneth Brock, Biglow Canyon Wind Farm technician; Bill Woolley, journeyman wireman; Xiaofeng Chen, Boardman coal plant operator; Cristina Flores, customer service representative*

Images on back, from top: *Leadman Repairman Robert Thompson; Doug Honeycutt, Transmission & Distribution dispatcher; Paul Hird, Beaver plant equipment manager*





Portland General Electric

Corporate Headquarters
121 SW Salmon Street | Portland, OR 97204
PortlandGeneral.com