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, 2010

OR

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

For the Transition period from ______ to ______

Commission File Number 1-5532-99

PORTLAND GENERAL ELECTRIC COMPANY

(Exact name of registrant as specified in its charter)

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

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

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 (§ 229.405 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 30, 2010, the aggregate market value of voting common stock held by non-affiliates of the Registrant was $1,377,258,515. For purposes of this calculation, executive officers and directors are considered affiliates.

As of February 18, 2011, there were 75,316,419 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 2011 Annual Meeting of Shareholders to be held on May 11, 2011.

PORTLAND GENERAL ELECTRIC COMPANY
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2010

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DEFINITIONS

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

Abbreviation orAcronym	Definition
AFDC	Allowance for funds used during construction
BART	Best Available Retrofit Technology
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
CUB	Citizens' Utility Board
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
kW	Kilowatt = one thousand watts of electricity
kWh	Kilowatt hours
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
OEQC	Oregon Environmental Quality Commission
OPUC	Public Utility Commission of Oregon
PCAM	Power Cost Adjustment Mechanism
Port Westward	Port Westward natural gas-fired generating plant
REP	Residential Exchange Program
RPS	Renewable Portfolio Standard
S&P	Standard & Poor's Ratings Services
SB 408	Oregon Senate Bill 408 (Oregon Revised Statutes 757.268)
SEC	United States Securities and Exchange Commission
SIP	Oregon Regional Haze State Implementation Plan
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. PGE operates as a cost-based, regulated electric utility, with revenue requirements and customer prices determined based upon the forecast cost to serve retail customers, including an opportunity to earn a reasonable rate of return. The Company's energy 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 manage its net variable power costs (NVPC). 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.

In 1997, Portland General Corporation, the former parent of PGE, merged with Enron Corporation (Enron), with Enron continuing in existence as the surviving corporation and PGE operating as a wholly-owned subsidiary of Enron through April 3, 2006. In December 2001, Enron, along with certain of its subsidiaries (collectively "Debtors"), filed for bankruptcy under Chapter 11 of the federal Bankruptcy Code. PGE was not included in the filing. On April 3, 2006, in accordance with Enron's Chapter 11 plan, PGE's 42.8 million shares of common stock held by Enron were canceled, PGE issued 62.5 million of new shares of common stock, with 27 million shares issued to the Debtors' creditors holding allowed claims and 35.5 million shares issued to a Disputed Claims Reserve, and PGE and Enron entered into a separation agreement. Following issuance of the new PGE common stock, PGE ceased to be a subsidiary of Enron. On June 18, 2007, the Disputed Claims Reserve sold substantially all of its remaining holdings of PGE stock in a public offering.

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 2010 its service area population was 1.7 million, comprising approximately 44% of the state's population. The Company added 4,937 customers during 2010 and served a total of 820,676 retail customers as of December 31, 2010.

As of December 31, 2010, PGE had 2,671 employees, with 872 employees covered under two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 837 and 35 employees and expire on February 28, 2012 and August 1, 2011, 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 www.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 www.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) and the Nuclear Regulatory Commission (NRC).

FERC Regulation

The Company is a "licensee" and a "public utility," 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 standards, natural gas pipelines, hydroelectric projects, accounting policies and practices, short-term debt issuances, and certain other matters. The Energy Policy Act of 2005 (EPAct 2005) granted the FERC statutory authority to implement mandatory reliability standards and also authorized monetary penalties for non-compliance with such standards and other FERC regulations. EPAct 2005 also provides for enhanced oversight of power and transmission markets, including protection against market manipulation.

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. As of December 31, 2010, PGE owned approximately 1,100 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 EPAct 2005, the FERC has adopted mandatory reliability standards for owners, users and operators of the bulk electric 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 to support reliable operation of the bulk electric system.

Pipeline—The Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978 provide 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% ownership interest in the 17-mile interstate pipeline that provides natural gas to its Port Westward and Beaver plants.

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.

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. Pursuant to an order issued by the FERC on January 29, 2010, the Company is authorized to issue up to $750 million of short-term debt through February 6, 2012.

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.

State of Oregon Regulation

PGE is subject to the jurisdiction of the Public Utility Commission of Oregon (OPUC), which is comprised of three members appointed by Oregon's governor to serve non-concurrent four-year terms. Current commissioners are Susan Ackerman, whose term expires March 31, 2012, and John Savage, whose term expires March 31, 2013. Ray Baum, Chairman of the OPUC since March 2010, resigned effective January 16, 2011 to accept a position as senior policy advisor to the chairman of the House Subcommittee on Communications and Technology in Washington D.C.; no successor has yet been named.

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 stock and long-term debt, prescribes accounting policies and practices, and reviews applications to sell utility assets, engage in transactions with affiliated companies, and 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 the state's governor, with staff support provided by the Oregon Department of Energy.

Ratemaking—Under Oregon law, the OPUC is required to ensure that the prices and terms of service are fair, non-discriminatory, and provide regulated companies an opportunity to earn a fair return on their investments. Customer prices are determined through formal ratemaking proceedings that generally include testimony by participating parties, data requests, 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.

- *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. Based upon such factors, revenue requirements and retail customer price changes are proposed. PGE's most recent general rate cases were the 2009 General Rate Case, which became effective on January 1, 2009, and the 2011 General Rate Case, which became effective on January 1, 2011. For additional information, see the Overview section of 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 NVPC, which consists of the cost of power and fuel (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 constraints and requirements. An initial NVPC forecast, submitted to the OPUC by April 1 each year, is updated during the year and finalized in November. 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 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 that included in base prices. The PCAM utilizes an asymmetrical deadband within which PGE absorbs cost variances, with a 90/10 sharing of such variances between customers and the Company outside of the deadband. 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 last authorized ROE. A final determination of any customer refund or collection is made by the OPUC through a public filing and review. The OPUC order in PGE's 2011 General Rate Case provides for a fixed deadband range of $15 million below, to $30 million above, forecasted NVPC, beginning in 2011. For additional information, see the Results of Operations section of 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 currently meets the 2011 requirement of the Act with existing renewable resources. Further, the Company expects that it will meet the 2015 requirements with additional resources included in its most recent Integrated Resource Plan (IRP). It is anticipated that requirements for subsequent years will be met by the acquisition of additional renewable resources, as determined pursuant to the Company's integrated resource planning process. The Act also allows Renewable Energy Credits, resulting from energy generated from qualified renewable resources placed in service after January 1, 1995, to be carried forward, with any excess of what is required to meet the Company's compliance obligation used to fulfill RPS requirements of future years. 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 on April 1 of each year for new renewable resources being 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 of 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.

Regulatory Treatment of Income Taxes—In 2005, Oregon adopted Senate Bill 408 (SB 408). The law attempts to match estimates of income taxes collected in revenues with the amount of income taxes paid to governmental entities by investor-owned electric and natural gas utilities or their consolidated group. The law requires that utilities file a report with the OPUC each year indicating the amount of taxes paid by the utility (with certain adjustments), as well as the amount of taxes authorized to be collected in rates. If the OPUC determines that the difference between taxes collected and taxes paid, as defined by the statute, is greater than $100,000, the utility is required to adjust future rates, with a regulatory asset or liability recorded for the total amount (including accrued interest) to be collected from, or refunded to, retail customers.

Application of the provisions of SB 408 can result in unusual outcomes, commonly termed the "double whammy" effect. As the provisions of the law apply to PGE, if the Company records higher actual operating income than forecast in its latest general rate case, customers are surcharged for the resulting increase in income taxes, further increasing earnings. Conversely, if the Company records lower actual operating income than forecast in its latest rate case, customers receive refunds for the resulting decrease in income taxes, further decreasing earnings.

For additional information, see Note 6, Regulatory Assets and Liabilities, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Retail Customer Choice Program—PGE's commercial and industrial customers have access to other providers (Electricity Service Suppliers, or ESSs) under the retail customer choice program. While such customers can purchase their electricity from an ESS, PGE continues to deliver the energy to the customer. The Company includes such "direct access" customers in its customer counts and includes energy delivered in its total retail energy deliveries. PGE served an average of 216 direct access customer accounts in 2010, compared to 262 in 2009 and 417 in 2008.

In 2010, ESSs supplied PGE customers with a total average load of approximately 124 MWa, representing 10% of PGE's non-residential load and 6% of the Company's total retail load for the year. In January 2011, the three ESSs registered to transact business with PGE supply an average load of approximately 139 MWa, representing 11% of the Company's non-residential load and 6% of total retail load.

In addition to providing customers with the option to be served by an ESS for a term of one year or less, PGE offers an option by which certain large non-residential 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 under a market price option.

Under market price options, PGE served commercial and industrial customers with an average load of approximately 16 MWa in 2010, representing approximately 1% of non-residential load and less than 1% of total retail load. While daily and monthly market price options were available in 2010, only the daily option will be available beginning in 2011.

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 customers that reflect the above- or below-market cost of energy resources owned or purchased by the Company, with such adjustments designed to ensure that costs or benefits of the program do not unfairly shift to those customers that continue to purchase their energy requirements from the Company.

Residential and small commercial customers can purchase electricity from PGE from a portfolio of rate options that includes a basic cost-of-service rate, a time-of-use rate, and renewable resource rates. Approximately 77,000, 82,000, and 71,000 customers were enrolled in renewable energy options as of December 31, 2010, 2009, and 2008, respectively. Approximately 2,100, 2,130, and 2,058 customers were enrolled in time-of-use options as of December 31, 2010, 2009, and 2008, respectively.

Energy Efficiency Funding—Oregon's electricity restructuring law also 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 $48 million was billed to customers for this charge in both 2010 and 2009.

PGE also remits to the ETO amounts collected under an Energy Efficiency Adjustment tariff to fund additional energy efficiency measures. The tariff, which became effective on June 1, 2008, initially included an approximate 1% charge for eligible customers that provided about $14 million annually for measures that enable customers to reduce their energy use. Effective January 1, 2010, the charge was increased to approximately 1.5%, which provides approximately $24 million annually.

Decoupling—The decoupling mechanism, initially authorized by the OPUC in PGE's 2009 General Rate Case, is intended to provide for recovery of reduced revenues resulting from a reduction in electricity sales attributable to energy efficiency and conservation efforts by residential and certain commercial customers. The mechanism provides for customer collection 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 general rate case.

The initial twelve month term of the mechanism, which ended January 31, 2010, resulted in an approximate $2.7 million customer refund, which is being credited to customers over a one-year period that began June 1, 2010. During 2010, the Company recorded an estimated customer collection of $8 million, as weather adjusted use per customer was lower than levels included in the 2009 General Rate Case. Pending review and approval by the OPUC, any resulting collections from customers would be expected over a one-year period beginning June 1, 2011.

As part of the Company's 2011 General Rate Case, the OPUC authorized the continued use of the decoupling mechanism through December 31, 2013, with conversion to an annual calendar basis.

Regulatory Accounting

As a regulated public utility, PGE is subject to generally accepted accounting principles for regulated operations to reflect the effects of rate regulation in its financial statements. These principles provide for the deferral as regulatory assets of certain actual or anticipated 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."

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Customers and Revenues

PGE conducts retail electric operations exclusively in Oregon within a state-approved service area. Retail customers are generally classified within one of the following three categories: i) residential; ii) commercial; or iii) industrial. 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 competes with ESSs to supply the energy needs of commercial and industrial customers. Customers who choose to purchase their energy requirements from an ESS continue to receive transmission and delivery services from PGE. For additional information on customer options, see "*Retail Customer Choice Program*" within the Regulation and Rates section of this Item 1.

The following table summarizes PGE's revenues for the years presented, with dollars in millions:

	Years Ended December 31,					
	2010		2009		2008	
	Amount	**%**	**Amount**	**%**	**Amount**	**%**
Retail:						
Residential	$ 803	45%	$ 856	47%	$ 796	46%
Commercial	601	34	642	36	606	35
Industrial	221	12	166	9	150	8
Subtotal	1,625	91	1,664	92	1,552	89
Other accrued revenues, net	39	2	(7)	—	(44)	(2)
Total retail revenues	1,664	93	1,657	92	1,508	87
Wholesale revenues	87	5	112	6	195	11
Other operating revenues	32	2	35	2	42	2
Revenues, net	$ 1,783	100%	$ 1,804	100%	$ 1,745	100%

The following table provides certain averages for the years presented regarding retail customers who purchase their energy requirements from the Company*:

	Years Ended December 31,		
	2010	2009	2008
Average usage per customer (in kilowatt hours):			
Residential	10,384	11,059	11,080
Commercial	68,040	70,853	72,486
Industrial	12,986,466	9,343,838	11,392,166
Average revenue per customer (in dollars):			
Residential	$ 1,049	$ 1,111	$ 1,066
Commercial	5,769	6,127	5,996
Industrial	859,251	660,839	730,994
Average revenue per kilowatt hour (in cents):			
Residential	10.10¢	10.05¢	9.62¢
Commercial	8.48	8.65	8.27
Industrial	6.62	7.07	6.42

* Excludes customers who purchase their energy from ESSs.

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

Retail Revenues

Retail customers are classified within residential, commercial, and industrial classes, with no single customer representing more than 4% of PGE's total retail revenues or 5% of total retail deliveries. Commercial and industrial customer classes are not dominated by any single industry. While the 20 largest commercial and industrial customers constituted 10% of total retail revenues in 2010, they represented nine different groups, including retail, high technology, paper manufacturing, metal fabrication, health services and governmental agencies. 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. Pricing of service to the residential class is based on the costs PGE incurs to provide electric service.

Residential demand is sensitive to the effects of weather, with demand historically highest during the winter heating season although, 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 eventually lead to a decrease in demand from the Company's residential customers. Residential demand is also impacted by energy efficiency measures; however, the decoupling mechanism substantially mitigates the financial effects of such measures.

During 2010, total residential deliveries decreased 5.7% compared to 2009, with milder weather conditions accounting for nearly half of the decrease. During 2009, total residential deliveries remained comparable to 2008; however, on a weather adjusted basis they declined 2.5%.

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 generally not affected as much by weather as the residential class. In 2010, however, the weather did contribute to the decline in deliveries compared to 2009. 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 decoupling mechanism.

During 2010, as the Oregon economy lost approximately 0.9% of its payroll, the Company's commercial energy deliveries decreased 3.7% compared to 2009 with milder weather, including a very cool summer in 2010, contributing about one-third of the decline. During 2009, as the Oregon economy lost about 6.2% of its payroll, the Company's commercial energy deliveries decreased 3.6% compared to 2008.

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 affected by national and global economic conditions. Weather has little impact on this customer class.

A change in Oregon's economic activity can also lead to a change in energy demand from the Company's industrial customers. In 2010, the Company's industrial energy deliveries rose 3.3% compared to 2009, driven by increased production levels by certain industrial customers in the latter half of 2010. In 2009, total energy deliveries to industrial customers decreased 9.3% compared to 2008 as industrial production declined.

The following table reflects averages over the past three year period by customer class. Retail energy deliveries and retail revenues are expressed as a percentage of the totals:

Customer Class	Average Customers	Energy Deliveries	Revenues
Residential	714,362	40%	51%
Commercial	101,188	39	38
Industrial	266	21	11

Other accrued revenues, net consists of items that are not currently included in customer prices, but are expected to be included in prices in a future period. Such amounts include deferrals recorded under SB 408 and regulatory mechanisms for the renewable adjustment clause, the power cost adjustment, and decoupling. See “State of Oregon Regulation” in the Regulation and Rates section of this Item 1 for further information on these items.

Other accrued revenues also include deferrals recorded pursuant to the Residential Exchange Program (REP). Under the REP, the Bonneville Power Administration (BPA) provides federal hydropower benefits to residential and small farm customers of certain investor-owned electric utilities. PGE receives monthly payments from BPA under the program and passes such payments along to eligible customers in the form of monthly billing credits. In September 2008, the BPA and PGE entered into an agreement that provides for monthly payments through the term of the agreement, which extends to September 2011. PGE received payments totaling $44 million in each of the twelve month periods ended September 30, 2010 and 2009, which were credited to customers. Payments for the twelve month period ending September 30, 2011 are expected to be approximately $49 million, with benefits to be credited to eligible customers. The Company will continue to pursue ongoing benefits for its customers under the REP and, along with other investor-owned utilities in the Pacific Northwest, is currently in settlement negotiations that would provide benefits from October 1, 2011 until the year 2028.

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, manage risk, and administer its current long-term wholesale contracts. The Company’s participation includes purchases and sales of power that result from economic dispatch decisions for its own generation, which contributes to PGE’s ability to secure reasonably priced power for its 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.

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 the sale of excess natural gas and oil, as well as revenues from transmission services, excess transmission capacity resales, pole contact rentals, and certain other electric services provided to customers.

Seasonality

Demand for electricity by PGE’s residential customers is affected by seasonal weather conditions, as discussed above. Heating and cooling degree-days are common measures used to analyze the effect of weather on the demand for electricity. Heating and cooling degree-days, which measure how much the average daily temperature varies from 65 degrees over a period of time, indicate the extent to which customers are likely to use, or have used, electricity for heating or air conditioning. The higher the numbers 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
2010	4,187	314
2009	4,391	627
2008	4,582	474
15-year average for 2010	4,192	473

The table above indicates that during 2010, heating degree-days were down about 5% from the prior year, while in 2009 demand for heating was greater than the 15-year average, but less than what it was in 2008. Demand for electricity for air conditioning was down in 2010 due to the 50% decline in cooling degree-days from 2009, which saw an unusually warm summer, while 2008 was a near average cooling degree year.

PGE’s all-time high net system load peak of 4,073 MW occurred in December 1998. The Company’s all-time “summer peak” of 3,949 MW occurred in July 2009, driven by unusually warm weather, and exceeded the December 2009 “winter peak” of 3,851 MW. The following table shows the Company’s average winter and summer loads for the periods indicated along with the corresponding peak load and month in which it occurred:

		Average Load MW	Month	Peak Load MW
2010	Winter	2,445	November	3,582
	Summer	2,220	August	3,544
2009	Winter	2,658	December	3,851
	Summer	2,267	July	3,949
2008	Winter	2,691	December	4,031
	Summer	2,324	August	3,743

The Company tracks and evaluates both base load growth and peak capacity 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, 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 reserves.

Power Supply

PGE relies upon its generating resources as well as short- and long-term power 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.

PGE's base generating resources consist of five thermal plants, 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 a given plant 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. Availability represents the percentage of the year the plant was available for operations, which reflects the impact of planned, forced and maintenance outages. For a complete listing of these facilities, see Item 2.—"Properties."

The Company also promotes the expansion of renewable energy resources, as well as energy efficiency measures, to meet its energy requirements and enhance customers' ability to manage their energy use more efficiently.

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

	As of December 31,					
	2010		2009		2008	
	Capacity	%	Capacity	%	Capacity	%
Generation:						
Thermal:						
Natural gas	1,157	24%	1,175	26%	1,175	26%
Coal	670	14	670	15	670	15
Total thermal	1,827	38	1,845	41	1,845	41
Hydro	489	10	489	11	489	11
Wind	450	9	275	6	125	3
Total generation	2,766	57	2,609	58	2,459	55
Purchased power:						
Long-term contracts:						
Capacity/exchange	540	11	640	14	654	15
Mid-Columbia hydro	507	10	548	12	545	12
Confederated Tribes hydro	150	3	150	3	150	3
Wind	44	1	35	1	35	1
Other	221	5	233	5	233	5
Total long-term contracts	1,462	30	1,606	35	1,617	36
Short-term contracts	612	13	315	7	379	9
Total purchased power	2,074	43	1,921	42	1,996	45
Total resource capacity	4,840	100%	4,530	100%	4,455	100%

For information regarding actual generating output and purchases for the years ended December 31, 2010, 2009 and 2008, see the Results of Operations section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Generation

That portion of PGE's energy 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. These two coal-fired generating facilities provided approximately 26% of the Company's total retail load requirement in 2010, compared to 20% in 2009 and 27% in 2008. The Company's three natural gas-fired generating facilities, Port Westward, Beaver, and Coyote Springs, provided approximately 24% of its total retail load requirement in 2010, 2009 and 2008. These thermal plants, which have a combined capacity of approximately 1,157 MW, continue to provide reliable power for customers. Plant availability, excluding Colstrip, was 94% in 2010, 84% in 2009 and 89% in 2008, with Colstrip availability 95% in 2010, 68% in 2009 and 97% in 2008.

Hydro The Company's FERC-licensed hydroelectric projects consist of two plants on the Deschutes River near Madras, Oregon, four plants on the Clackamas River and one on the Willamette River. The licenses for these projects expire at various dates from 2035 to 2055. These plants, which have a combined capacity of 489 MW, provided 10% of the Company's total retail load requirement in 2010, 2009 and 2008, with availability of 99% in those years. 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 no sooner than January 2, 2019 and no later than July 1, 2021. The Tribes have a second option to purchase an undivided 0.02% interest in Pelton/Round Butte at its discretion no sooner than December 31, 2036. 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 installed capacity of approximately 450 MW. It was completed and placed in service in three phases between December 2007 and August 2010. In 2010, Biglow Canyon provided 4% of the Company's total retail load requirement, compared to 3% in 2009 and 2% in 2008, with availability at 96% in 2010, 97% in 2009, and 92% in 2008.

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, 2010, there were 27 projects that together can provide approximately 53 MW of diesel-fired capacity at peak times. In addition, there were 15 projects under construction that are expected to provide an additional 34 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, option, and futures contracts to manage its exposure to volatility in natural gas prices.

Coal *Boardman*—PGE has fixed-price purchase agreements that provide coal for Boardman through 2011. 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.

In the first half of 2011, PGE intends to seek requests for proposal for the purchase of coal for 2012 and beyond. The terms of the contract and quality of coal is 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 the Capital Requirements section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Natural Gas *Port Westward and Beaver*—Firm gas supplies for Port Westward and Beaver are purchased up to 60 months in advance, based on anticipated operation of the plants. PGE owns 79% 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.

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 5-day supply of ultra low sulfur diesel fuel oil at the plant site as of December 31, 2010. The current operating permit for Beaver limits the number of gallons of fuel that can be burned daily, which effectively limits the daily hours of operation of Beaver.

Coyote Springs—The Coyote Springs generating station utilizes 41,000 Dth/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, based on anticipated operation of the plant. Although Coyote Springs was designed to also operate on 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 energy requirements. The Company utilizes short- and long-term wholesale power purchase contracts to provide the most favorable economic mix on a variable cost basis. Such contracts have terms ranging from one month to 30 years and expire at varying dates through 2036.

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—These five contracts provide PGE with firm capacity to help meet the Company's peak loads. The contracts range from 10 MW to 300 MW and expire at various dates from February 2011 through December 2016. They include seasonal exchange contracts with other western utilities that help meet both winter- and summer-peaking requirements.

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 four hydroelectric projects on the mid-Columbia River. The projects currently provide a total of 507 MW of firm capacity, with actual energy received 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.

Wind—The Company has three long-term contracts, which extend to various dates between 2028 and 2035, that provide for the purchase of renewable wind-generated electricity.

Other—These primarily consist of long-term contracts to purchase power from various counterparties, including other Pacific Northwest utilities, over terms extending up to 2018.

Other also includes contracts that provide for the purchase of renewable solar-powered electricity. PGE has invested in three photovoltaic solar power projects, with a combined installed capacity of 3.6 MW, through separate limited liability companies as follows:

- Installation completed in December 2008, the first project has an installed capacity of approximately 104 kW and is located on property owned by the Oregon Department of Transportation (ODOT). PGE purchases any excess energy generated from this facility pursuant to a net metering arrangement with ODOT;

- Installation completed in January 2009, the second project has a total installed capacity of approximately 1.1 MW and is located on the rooftops of three distribution warehouses in Portland, Oregon. PGE purchases 100% of the energy generated from these facilities; and

- Installation completed in July 2010, the third project has a total installed capacity of approximately 2.4 MW and is located on the rooftops of seven distribution warehouses in Portland, Oregon. PGE purchases 100% of the energy generated from these facilities.

In September 2010, PGE entered into two 25-year purchase agreements for the power to be generated from two solar photovoltaic projects to be installed near Salem, Oregon. The construction of the projects is expected to be completed by mid-2011, with PGE then purchasing the power generated from these facilities, which are designed to have a combined generating capacity of 2.8 MW.

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 one hour 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 is required to file with the OPUC an Integrated Resource Plan (IRP) within two years of its previous IRP acknowledgment order. 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.

On November 5, 2009, PGE filed an IRP that included an action plan for the acquisition of new resources and a 20-year strategy that outlined long-term expectations for resource needs and portfolio performance. PGE projected that it would need 873 MWa of new resources by 2015, increasing to 1,396 MWa by 2020, to meet expected customer demand. Such projected energy gaps are driven primarily by continued load growth and the expiration of certain long-term power supply contracts. If Boardman were to cease operations, the projected energy gap would increase by approximately 374 MW.

To meet the projected energy requirements, the IRP included energy efficiency measures, new renewable resources, new transmission capability, new generating plants, and improvements to existing generating 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;

- An additional 122 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 services territory. For additional information on the Cascade Crossing Transmission Project (Cascade Crossing), see the Transmission and Distribution section in this Item 1;

- New natural gas generation facilities to help meet additional base load requirements estimated at 300 to 500 MW, which is expected to be in service in or around 2015;

- New natural gas generation facilities to help meet peak capacity requirements estimated at up to 200 MW, which is expected to be in service in or around 2013; and

- Future plans for the Boardman plant, including the addition of certain emissions controls and the continuation of coal-fired operation of the plant through 2020.

After considerable review and public comment, on November 23, 2010, the OPUC issued an order that acknowledged PGE's 2009 IRP, as amended, with certain requirements. Among those requirements, the OPUC directed the Company in its next IRP filing to: (i) include an updated cost benefit analysis of Cascade Crossing; (ii) provide information regarding the ability of customers to respond to high demand periods by curtailing use; (iii) consider the potential savings from operating its distribution system in the lower portion of the acceptable voltage ranges; (iv) include a study addressing the cost and impacts of integrating variable wind generation into PGE's system; (v) evaluate the use of unbundled Renewable Energy Credits in its strategy to meet RPS requirements; and (vi) evaluate alternatives to the physical compliance with RPS requirements. The OPUC also directed the Company to file its next IRP no later than November 2012.

For additional information about emissions controls for the Boardman plant, see the Capital Requirements section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

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 2010, PGE delivered approximately 20 million MWh in its balancing authority area through approximately 1,100 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 BPA to transmit a significant amount of the Company's generation to its distribution system. PGE's transmission system, together with contractual rights to other transmission systems, enables the Company to integrate and access generation resources to meet its customers' load 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 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 the FERC's Standards of Conduct, PGE's transmission business is managed and operated independently from its power marketing business.

PGE's current IRP, which has been acknowledged by the OPUC, includes a proposal for a double-circuit 200-mile, 500 kV transmission project (the Cascade Crossing Transmission Project) that would help meet growing electricity demand and ensure future grid reliability by interconnecting new and existing energy resources in eastern Oregon to the Company's service territory. The Company has agreed to include further cost benefit analysis of the project in its next IRP filing. PGE is coordinating with other utilities in planning the project and is actively engaged in the federal, state, and tribal permitting processes. The Company has signed Memorandums of Understanding with certain parties, including the BPA, PacifiCorp, and Idaho Power Company, concerning the Cascade Crossing Transmission Project.

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 are provided 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 Item 2.—"Properties."

Environmental Matters

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

Air Quality Standards

Clean Air Act—PGE's operations, primarily its thermal generating plants, are subject to regulation under the federal Clean Air Act (CAA). Primary pollutants addressed by the CAA that affect PGE are sulfur dioxide (SO_2), nitrogen oxides (NOx), carbon monoxide, and particulate matter. The states in which PGE facilities are located, Oregon and Montana, also implement and administer certain portions of the CAA and have set standards that are at least equal to federal standards.

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

For information on regulatory and legal proceedings alleging that PGE is in violation of certain standards under the CAA at Boardman see Note 18, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Regional Haze Rules—In accordance with federal regional haze rules aimed at visibility impairment in certain federally protected areas, PGE submitted an initial analysis and control plan to the Oregon Department of Environmental Quality (DEQ) for Boardman in 2007, after it was determined that the plant would be subject to a Regional Haze Best Available Retrofit Technology (BART) Determination, as required under the CAA.

In December 2010, the Oregon Environmental Quality Commission (OEQC) approved revised BART rules, which provide for the coal-fired operation at Boardman to cease no later than December 31, 2020 and require the installation of controls at Boardman to reduce NOx and SO_2 emissions in 2011 and a Dry Sorbent Injection (DSI) system in 2014 to further reduce SO_2. The revised rules also require the use of a lower sulfur coal and testing of the DSI system to determine attainable emission levels. The total cost of the controls, including approximately $7 million for mercury controls as discussed below in "*Mercury Rules - Oregon,*" is estimated at approximately $60 million. The revised rules are subject to EPA approval, which is expected by May 2011.

The EPA has been considering new emission limits under the CAA's National Emission Standards for Hazardous Air Pollutants (NESHAP) regulating hazardous air pollutant emissions from coal- and oil-fired electric generating units. According to a 2009 consent decree, the EPA must publish its proposed Electric Generating Unit NESHAP by March 16, 2011. Emission limits included in the NESHAP must be based on the application of maximum achievable control technology. These regulatory requirements, which are due to be final by the end of 2011, could have an influence on the ultimate control package and remaining operating life of Boardman.

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

Once the EPA has approved the OEQC rules regarding BART and an early closure of Boardman, PGE would seek to recover its remaining investment in Boardman (approximately $125 million as of December 31, 2010) plus the cost of the emissions controls and any decommissioning or other costs related to the plant's closure, as well as the construction or acquisition costs of replacement generating capacity, in future customer prices. The OPUC approved a tariff in the Company's 2011 General Rate Case that would provide for the recovery of the Company's remaining investment in the Boardman generating plant over a shortened operating life, if that were to occur.

Mercury Rules—Oregon and Montana have adopted regulations concerning mercury emissions that are expected to have, or have had, an impact on the Company as follows:

Oregon—The OEQC has adopted final rules that pertain to mercury emissions from Boardman. Such rules require compliance with stated mercury limits by July 1, 2012, although this deadline can be extended by two years under certain circumstances. PGE has submitted its mercury control plan to the DEQ outlining measures it plans to take to comply with the state's mercury emissions rules. PGE has agreed to install controls that are expected to eliminate 90% of the mercury emissions from the plant. These controls are expected to be installed in 2011 at a total estimated cost of approximately $7 million.

Montana—The Montana Board of Environmental Review adopted final rules on mercury emissions from coal-fired generating plants in Montana, including Colstrip, which required compliance with mercury emission limits by January 1, 2010. With the installation of additional mercury control systems now completed, the Colstrip units are in compliance with these requirements.

Climate Change—State, regional, and federal legislative efforts continue with respect to establishing regulation of greenhouse gas (GHG) emissions and their potential impacts on climate change. Recent or pending environmental measures include the following:

- In 2007, the State of Oregon adopted a goal to reduce GHG emissions to 10% below 1990 levels by 2020. The non-binding goal does not mandate reductions by any specific entity nor does it include penalties for failure to meet the goal; however, it serves as a policy guideline for the state.

- In 2009, the U.S. House of Representatives approved the American Clean Energy and Security Act of 2009, which seeks to establish a cap and trade system for GHG emissions. The U.S. Senate did not act and it is uncertain whether a cap and trade system will move forward in the near term. However, it is expected that Congress will debate funding levels for the EPA, which is moving ahead with efforts to set regulations on GHG emissions under its existing CAA authority.

- The Oregon Emissions Performance Standard, passed by the Oregon legislature in 2009, prohibits utilities from entering into commitments with energy facilities, or contracts for energy, with a duration of more than five years, for which the associated emissions exceed prescribed levels. This standard may have an impact on the Company's ability to contract for, or prices it pays to acquire, energy to meet future customer needs. Other states in the western electricity grid, including Washington and California, have also enacted similar legislation.

- Effective January 1, 2010, the EPA required mandatory measurement and reporting of GHG emissions. PGE is subject to these requirements and is meeting the monitoring and reporting requirements. Reported data will be used to establish a baseline for measuring progress toward any future emissions reduction targets in the United States. In addition, the EPA is moving ahead with efforts to regulate GHG emissions under the CAA.

Any laws that impose mandatory reductions in GHG emissions could have a material impact on PGE, 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, although there can be no guarantee such recovery would be granted.

The ultimate impact that the above regulatory requirements and emissions controls will have on future operations, costs, or generating capacity of PGE's thermal generating facilities is not yet determinable.

Water Quality Standards

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, the DEQ is responsible for reviewing proposed projects under this requirement to ensure that federally approved activities will meet water quality standards and policies established by the state. PGE has obtained necessary permits where required, and has certificates of compliance for its hydroelectric operations under the FERC licenses.

Endangered Species and Wildlife Protection

Fish Protection—Populations of many migratory fish species in the Pacific Northwest have declined significantly over the last several decades. Many of these distinct populations have been granted protection under the federal Endangered Species Act (ESA). Long-term recovery plans for these species include major operational changes to the region's hydroelectric projects, which have resulted in reductions in hydroelectric generation capacity and the seasonal shifting of hydroelectric generation from the fall and winter periods to the spring and summer periods. PGE has purchase contracts for power generated at affected facilities on the mid-Columbia River in central Washington and may be adversely affected by such reductions and seasonal shifting at those facilities. The timing of stored water releases also affects the availability and price of power in the regional wholesale market.

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. 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.

The following are related to conditions outlined in the Company's FERC operating licenses:

- The FERC approved a 40-year license term for the Company's hydroelectric project on the Clackamas River in December 2010. Operating conditions required in the new license are expected to result in a minor reduction in power production.

- As required by the FERC license for its Pelton/Round Butte project on the Deschutes River, which is in effect until 2055, PGE constructed a selective water withdrawal system in an effort to restore fish passage on the upper portion of the river. The system, which was placed in service in January 2010, is designed to collect juvenile salmon and steelhead, allowing them to bypass the dam when migrating to the Pacific Ocean. The system will also help regulate downstream water temperature.

- As required under the FERC license for its Willamette River hydroelectric project, in effect until 2035, PGE implemented several fish protection measures, the performance of which will receive ongoing evaluation.

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 in place. PGE has developed and implemented such a plan to reduce risks to bird species that can result from Company operations.

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, which have been exempt from federal hazardous waste regulations under the RCRA. The EPA is revisiting this exemption and currently considering listing these residuals as hazardous wastes, which would likely increase the Company's cost of handling these materials and could affect operations. The Company cannot predict the possible impact of this matter until the EPA provides further guidance on the proposed rules. The EPA has indicated that the timing of issuance of a final rule has yet to be determined. If PGE were to incur incremental costs as a result of changes in the regulations, the Company would seek recovery in customer prices, although there can be no guarantee such recovery would be granted.

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. PGE is listed by the EPA as a Potentially Responsible Party (PRP) at 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. The EPA subsequently included Portland Harbor on the federal National Priority List as a Superfund site pursuant to CERCLA and listed sixty-nine PRPs, including PGE, which 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. As a result, PRPs now number in excess of one hundred.
>
> *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.

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 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. The OPUC has the authority to disallow the recovery of any costs that it considers excessive or imprudently incurred. Further, the regulatory process does not guarantee that PGE will be able to achieve the earnings level authorized. Although the OPUC is required to establish rates that are fair, just and reasonable, it has significant discretion in the interpretation of this standard.

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. 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. For additional information regarding the 2011 General Rate Case, see the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

PGE utilizes a PCAM by which the Company can adjust future prices to reflect a portion of the difference between each year's forecasted ("baseline") and actual NVPC that falls outside of a pre-established "deadband." Application of this cost sharing mechanism requires that PGE absorb certain power cost increases before the Company is allowed to recover any amount from customers. Accordingly, application of the PCAM is expected to only partially mitigate the potentially adverse financial impacts of forced generating plant outages, severe weather, reduced hydro availability, and volatile wholesale energy prices. PGE's actual 2010 NVPC were $12 million below the baseline but within the deadband for the year; accordingly, no refund to retail customers is expected to be required. Actual 2009 NVPC, however, exceeded the baseline by $22 million. As this amount was below the threshold for recovery under the PCAM, no collection from retail customers was allowed, and PGE absorbed these increased costs. The OPUC order in PGE's 2011 General Rate Case provides for a fixed deadband range of $15 million below, to $30 million above, forecasted NVPC, beginning in 2011.

The current weak economy has reduced the demand for electricity and has impaired the financial stability of some of PGE's customers, which has affected the Company's results of operations and could continue to do so.

The continued weak economy has resulted in sustained high unemployment in Oregon and has resulted in reduced demand for electricity, which could continue. Such reduction has affected the Company's results of operations and cash flows and could continue to do so. Further, the Company's vendors and service providers could experience cash flow problems and be unable to perform under existing or future contracts.

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, reduced efficiency, or higher operating costs.

PGE's current position as a "short" utility requires that the Company supplement its own generation with wholesale market purchases to meet its energy requirements. In addition, long-term increases in both the number of customers and demand for energy will require continued expansion and reinforcement 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, 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.

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 or under short-term, long-term or variable-priced contracts. 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 market value of derivative instruments and cash requirements to purchase power and natural gas. Although the Company's PCAM can be expected to partially mitigate adverse financial effects related to market conditions, cost sharing features of the mechanism do not provide for full recovery in customer prices.

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. From the last half of 2008 through 2010, PGE has been required to provide increased levels of margin deposits for its existing purchased power and natural gas agreements as a result of depressed wholesale power and natural gas prices.

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 Company may not be able to fully recover these increased costs through ratemaking.

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

Weather conditions can adversely affect PGE's revenues and costs, impacting the Company's financial and operating results. Variations in temperatures can affect customer demand for electricity, with warmer-than-normal winters or cooler-than-normal summers reducing energy sales and revenues. 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, full recovery is not assured. Inability to fully recover such costs in future prices could have a negative impact on the Company's results of operations.

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 and to 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 business plan as currently scheduled.

Access to capital and credit markets is important to PGE's continued ability to operate. The Company potentially faces significant capital requirements over the next three to five years and expects to issue debt and equity securities to fund certain projects. In addition, because of contractual commitments and regulatory requirements, the Company may have limited 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 of 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 business 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 with assurance. 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 PGE's 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 operating results.

PGE derives a significant portion of its power supply from its own hydroelectric facilities and from those owned by certain public utility districts in the state of Washington with which the Company has long-term purchase contracts. 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 operating results.

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

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.

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 operations or results of operations.

PGE expects that future legislation or regulations could result in limitations on greenhouse gas emissions from the Company's fossil fuel-fired electric generating facilities. Legislation has been introduced in the U.S. Congress that would require greenhouse gas emission reductions from such facilities as well as other sectors of the economy. Although no such legislation has yet been enacted, the House of Representatives passed climate legislation in June 2009. 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 expected 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. Although the Company would likely seek to recover such costs through the ratemaking process, there can be no assurance that such recovery would be granted.

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 $600 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 of 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 emissions from thermal generating plants could result in increased capital expenditures and changes to PGE's operations that could increase operating costs, reduce generating capacity, and adversely affect the Company's results of operations.

In December 2010, the OEQC adopted a rule that would require installation of emissions controls at Boardman as well as the end to coal fueled operations at the plant by the end of 2020. The Company expects the EPA to issue a decision on the OEQC rule by May 2011. For additional information, see "Environmental Matters" in Item 1.—"Business."

Although the full impact of required state and federal remediation measures is not yet determinable, they could have an adverse effect on future operations, operating costs, and generating capacity at both Boardman and Colstrip. The Company would seek to recover through the ratemaking process any costs of additional emissions control equipment or emission reduction measures that may be required. However, there can be no assurance that such recovery would be granted.

In addition, PGE could be subject to litigation brought by environmental groups and other private parties alleging violations of state or federal law and seeking the imposition of penalties, damages, injunctive relief, and the closure of plants. For information regarding pending litigation, see Sierra Club et al. v. Portland General Electric Company in Item 3.—"Legal Proceedings."

Adverse 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, adversely affecting 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 2008, the fair value of the pension plan assets declined substantially, contributing to the pension plan's underfunded status of $120 million as of December 31, 2008. In 2009 and 2010, the fair value of the pension plan assets appreciated and changes in certain actuarial assumptions resulted in an improvement in the underfunded status of the pension plan to $85 million as of December 31, 2009 and $77 million as of December 31, 2010. The Company made a $30 million contribution to the pension plan in 2010 but expects to make no contribution in 2011, pursuant to the requirements of the federal Pension Protection Act.

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 and a Supplemental Executive Retirement Plan. 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. In 2008, PGE recorded a $17 million loss on the fair value of these assets, which reduced net income by $12 million for the year ended December 31, 2008. In 2009 and 2010, however, PGE recorded after-tax gains of $5 million and $3 million, respectively, related to increases in the fair value of the assets.

For additional information regarding PGE's contribution obligations under its pension and non-qualified benefit plans, see the "Contractual Obligations and Commercial Commitments" table in the Liquidity and Capital Resources section of 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. The cost and availability of natural gas and coal can also impact the cost and output of the Company's thermal generating plants.

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 consists of generation from hydroelectric projects on the Columbia, Clackamas, Deschutes, and Willamette rivers. Operation of these projects is subject to extensive 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 changes to federally-authorized activities, including those of hydroelectric 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, 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 generation available to meet the Company's energy requirements. The Company would likely seek recovery of any such expenditures through the ratemaking process; however, there can be no assurance that such recovery would be granted.

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 property is currently not available, however, the Company would likely seek recovery of large losses to such property through the ratemaking process. As there is no assurance that any recovery would be granted, however, any increased costs resulting from such damage could have an adverse effect on PGE's results of operations.

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 affects 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 an aging workforce with a significant number of employees approaching retirement age.

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.

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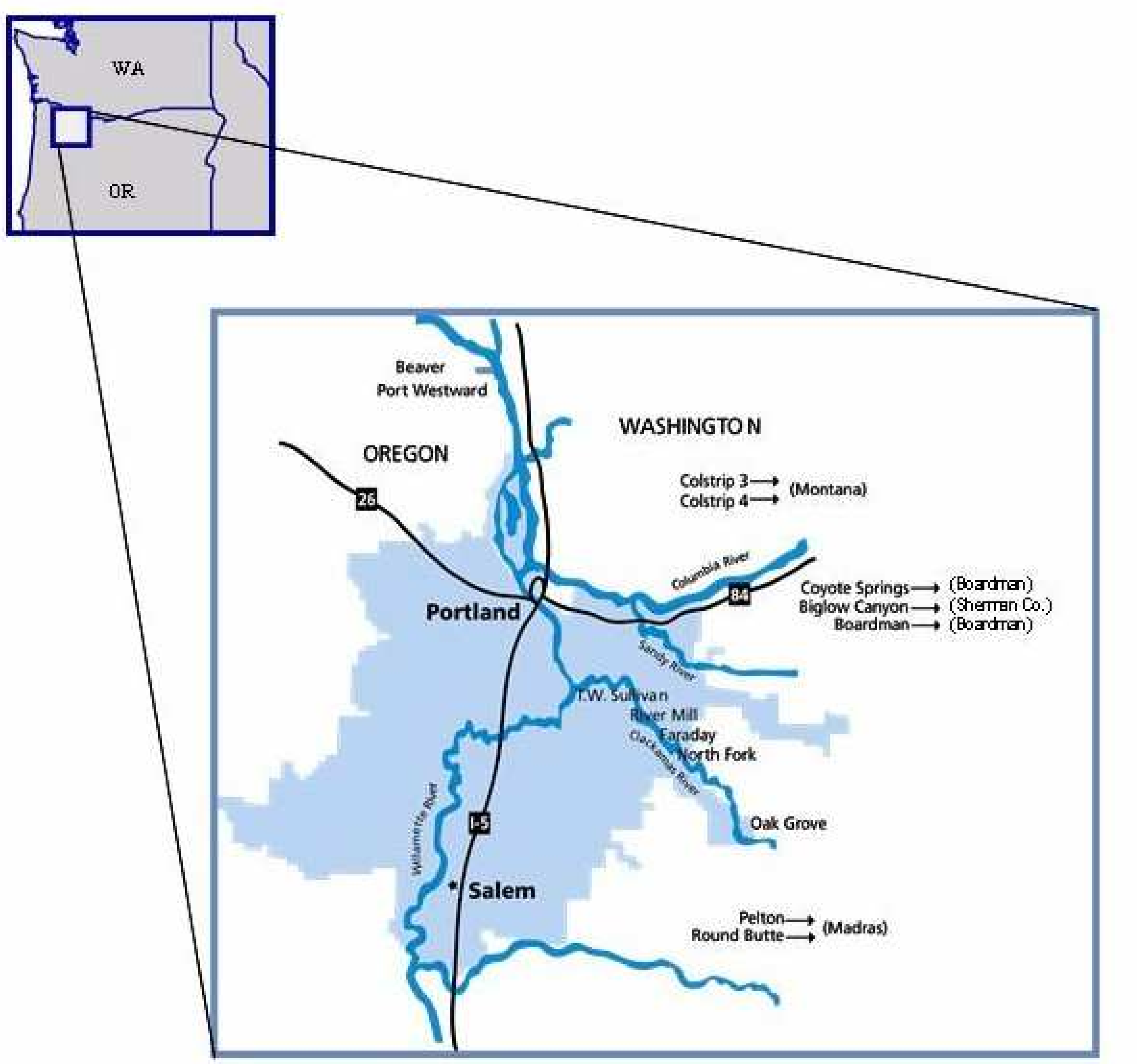
ITEM 2. PROPERTIES.

PGE's principal property, plant, and equipment are located on land owned by the Company in fee 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.

The Company's service territory and generating facilities are indicated below:



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Generating Facilities

The following are generating facilities owned by PGE as of December 31, 2010:

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	231	
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		2,766	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, 2050; 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 Interconnect. As of December 31, 2010, PGE owned an electric transmission system consisting of approximately 710 circuit miles of 500-kV line and 360 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 owns, or has contractual rights to, the following transmission facilities:

- 280 MW of capacity over the Montana Intertie from the Colstrip plant in Montana to BPA's transmission system;
- Approximately 3,000 MW of firm BPA transmission from remote resources and markets on BPA's system to PGE's service territory in Oregon;
- 300 MW of firm BPA transmission from mid-Columbia projects to the California-Oregon Intertie;
- 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; and
- 100 MW of the Pacific DC Intertie between Celilo, Oregon and Sylmar, in southern California.

The California-Oregon AC Intertie and the Pacific DC Intertie are used primarily for the transmission of interstate purchases and sales of electricity among utilities, including PGE.

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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.

Following the closure of Trojan, 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 and PGE requested from the OPUC a Declaratory Ruling regarding recovery of the Trojan investment and decommissioning costs. In August 1993, the OPUC issued a Declaratory Ruling in PGE's favor. The Declaratory Ruling was appealed to the Marion County Circuit Court, which, in November 1994, upheld the OPUC's Declaratory Ruling. 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, alleging that the OPUC lacked authority to allow PGE to recover Trojan costs through its rates. 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 contradicted the Court's November 1994 ruling. The 1996 decision 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, where it was consolidated with the earlier appeal of the 1994 decision.

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, but upheld the OPUC's authority to allow PGE's recovery of its undepreciated investment in Trojan and its costs to decommission Trojan (1998 Decision). The court remanded the matter to the OPUC for reconsideration of its 1995 Order in light of the court's decision.

In August 1998, PGE and the URP each filed a Petition for Review with the Oregon Supreme Court seeking review of that portion of the 1998 Decision relating to PGE's return on its undepreciated investment in Trojan. On November 19, 2002, the Oregon Supreme Court dismissed both Petitions for Review.

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 Settlement allowed PGE to remove from its balance sheet the remaining investment in Trojan of approximately $180 million at September 30, 2000, along with several largely offsetting regulatory liabilities. 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 on September 30, 2008 that required PGE to refund $33.1 million to customers. In the order, the OPUC also made the following findings:

- The OPUC has authority to order a utility to issue refunds under certain limited circumstances; and

- PGE's rates that were in effect for the period April 1, 1995 through September 30, 2000 were just and reasonable.

On October 22, 2008, the URP and the Class Action Plaintiffs (described in the Dreyer proceeding below) separately appealed the September 30, 2008 OPUC order to the Oregon Court of Appeals. A decision by the Oregon Court of Appeals remains pending.

The Company completed the distribution of the refund to customers, plus accrued interest, as required by the September 30, 2008 OPUC order.

Management cannot predict the ultimate outcome of these matters. Management believes, however, that these matters will not have a material adverse impact on the financial condition of the Company, but may have a material adverse impact on the results of operations and cash flows in a future reporting period.

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.

On January 17, 2003, two class action suits were filed in Marion County Circuit Court against PGE on behalf of two classes of electric service customers. 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.

On April 28, 2004, the plaintiffs filed a Motion for Partial Summary Judgment and on July 30, 2004, PGE also moved for Summary Judgment in its favor on all of the Class Action Plaintiffs' claims. On December 14, 2004, the Judge granted the Plaintiffs' motion for Class Certification and Partial Summary Judgment and denied PGE's motion for Summary Judgment. On March 3, 2005, PGE filed a Petition for a Writ of Mandamus 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. On March 29, 2005, PGE filed a second Petition for an Alternative Writ of Mandamus with the Oregon Supreme Court seeking to overturn the Class Certification.

On August 31, 2006, the Oregon Supreme Court issued a ruling on PGE's Petitions for Alternative Writ of Mandamus 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.

On October 5, 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.

On October 17, 2007, the plaintiffs in the class action suits filed a motion with the Marion County Circuit Court to lift the abatement. On February 10, 2009, the Circuit Court judge denied the plaintiff's motion to lift the abatement.

Management cannot predict the ultimate outcome of these matters. Management believes, however, that these matters will not have a material adverse impact on the financial condition of the Company, but may have a material adverse impact on the results of operations and cash flows in a future reporting period.

<u>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</u>, 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).

On July 25, 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 September 2001, upon completion of hearings, the appointed administrative law judge issued a recommended order that the claims for refunds be dismissed. In December 2002, the FERC re-opened the case to allow parties to conduct further discovery. In June 2003, the FERC issued an order terminating the proceeding and denying the claims for refunds. In November 2003 and February 2004, the FERC denied all requests for rehearing of its June 2003 decision. Parties appealed various aspects of these FERC orders to the U.S. Ninth Circuit Court of Appeals (Ninth Circuit).

On August 24, 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 its potential ties to the Pacific Northwest and that the FERC should not have excluded from the Pacific Northwest Refund proceeding purchases of energy made by the California Energy Resources Scheduling (CERS) division in the Pacific Northwest spot market. The Ninth Circuit remanded the case to the FERC to (i) address the new market manipulation evidence in detail and account for it 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. Two requests for rehearing were filed with the court and on April 9, 2009, the Ninth Circuit issued an order that denied the requests for rehearing. On April 16, 2009, the Ninth Circuit issued a mandate giving immediate effect to its August 24, 2007 order remanding the case to the FERC.

Since issuance of the mandate, certain parties proposing refunds have filed pleadings with FERC suggesting procedures on remand, attempting to initiate new proceedings, and containing additional evidence that they assert shows market-wide manipulation that justifies refunds from early in 2000. Parties opposing refunds, including PGE, have filed various pleadings that contest allegations of market-wide manipulation and urge the FERC to reaffirm, with a more detailed explanation of its consideration of market manipulation claims, its previous decision not to initiate proceedings to order refunds. As of the filing date of this report, the FERC has not issued an order in response to the Ninth Circuit remand.

On May 17, 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 21, 2001. The settlement with the California parties did not resolve potential claims from other market participants relating to transactions in the Pacific Northwest.

Management cannot predict the outcome of the Pacific Northwest Refund proceeding, or whether the FERC will order refunds in the Pacific Northwest, and if so, how such refunds would be calculated. Management believes, however, that the outcome will not have a material adverse impact on the financial condition of the Company, but may have a material adverse impact on PGE's results of operations and cash flows in a future reporting period.

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

On September 30, 2008, the plaintiffs filed a complaint against PGE for alleged violations of the federal Clean Air Act (CAA), Oregon's Regional Haze State Implementation Plan (SIP) at PGE's Boardman Coal Plant, the Plant's CAA Title V permit, and additional alleged violations of various environmental related regulations.

The plaintiffs seek injunctive relief that includes permanently enjoining PGE from operating the Boardman Coal Plant except in accordance with the CAA, Oregon's SIP, and the Plant's Title V Permit. In addition, plaintiffs seek civil penalties against PGE including $27,500 per day per alleged violation for violations occurring before March 15, 2004 and $32,500 per day per alleged violation occurring thereafter. The total amount of monetary penalties and damages asserted in the complaint cannot be determined with certainty. However, based solely on the complaint, the Company estimates that the amount is approximately $60 million.

On September 30, 2009, the District Court ruled on PGE's motion to dismiss most of the claims. In summary, the court denied PGE's motion with respect to most of the plaintiff's claims, but did grant PGE's motion with respect to certain of the plaintiff's claims. The principal claims that remain are (i) that PGE constructed Boardman without complying with the 1974 and 1977 federal pre-construction permitting requirements, (ii) that PGE modified Boardman in the 1990s without complying with Oregon's pre-construction permitting requirements, and (iii) that certain modifications to Boardman triggered new source performance standards (NSPS). Discovery in the case continues, with a tentative trial date set for August 2011.

Management cannot predict the ultimate outcome of this matter. Management believes, however, that it has strong defenses to the plaintiffs' claims and intends to vigorously defend against this lawsuit.

United States Environmental Protection Agency, Region 10 - Notice of Violation

On September 28, 2010, the EPA issued a Notice of Violation (NOV) to PGE in accordance with the CAA. The NOV states that the EPA has determined that the Company is violating the NSPS under Section 111 of the CAA, 42 U.S.C. Section 7411 *et seq.,* and Operating Permit requirements under Title V of the CAA, 42 U.S.C. Sections 7661 *et seq.*, at the Boardman plant. In the NOV, the EPA asserts that certain projects at the Boardman plant completed in 1998 and in 2004 triggered the NSPS, that PGE did not meet the emissions standards required by the regulations and that, therefore, PGE has operated the boiler at the Boardman plant in violation of the CAA. The NOV states the maximum civil penalties the EPA is authorized to impose under the CAA for violations of the NSPS (which range from $25,000 to $37,500 per day), but does not impose any penalties, or specify the amount of any proposed penalties with respect to the alleged violations. Accordingly, management cannot estimate the range of potential liability for the violations asserted in the NOV. In the NOV, the EPA has offered PGE an opportunity to confer about the violations cited and to present information on the specific findings of the EPA. PGE expects to meet with the EPA during the first quarter of 2011.

Management cannot predict the outcome of the claims asserted by the EPA in the NOV. Management believes, however, that it has strong defenses to these claims and intends to vigorously defend against them.

General

From time to time in the normal course of business, PGE is subject to various other regulatory proceedings, lawsuits, claims and other matters, certain of which may result in adverse judgments, settlements, fines, penalties, injunctions or other relief. Management currently does not believe any of these other matters will have a material adverse effect on the Company's financial position, results of operations or cash flows.

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 18, 2011, there were 1,121 holders of record of PGE's common stock and the closing sales price of PGE's common stock on that date was $22.75 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
2010			
Fourth Quarter	$ 22.65	$ 20.13	$ 0.260
Third Quarter	20.63	18.08	0.260
Second Quarter	20.60	18.10	0.260
First Quarter	20.66	17.46	0.255
2009			
Fourth Quarter	$ 21.39	$ 18.25	$ 0.255
Third Quarter	20.95	17.69	0.255
Second Quarter	20.26	16.43	0.255
First Quarter	19.88	13.45	0.245

While PGE expects to pay regular quarterly dividends on its common stock, the declaration of any dividends is at the discretion of the Company's Board of Directors. The amount of any dividend declaration depends upon factors that the Board of Directors deem 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,				
	2010	2009	2008	2007	2006
	(In millions, except per share amounts)				
Statement of Income Data:					
Revenues, net	$ 1,783	$ 1,804	$ 1,745	$ 1,743	$ 1,520
Gross margin	954	860	867	864	757
Income from operations	267	208	217	269	159
Net income	121	89	87	145	71
Net income attributable to Portland General Electric Company	125	95	87	145	71
Earnings per share—basic and diluted	1.66	1.31	1.39	2.33	1.14
Dividends declared per common share	1.035	1.010	0.970	0.930	0.680
Statement of Cash Flows Data:					
Capital expenditures	450	696	383	455	371

	As of December 31,				
	2010	2009	2008	2007	2006
	(Dollars in millions)				
Balance Sheet Data:					
Total assets	$ 5,491	$ 5,172	$ 4,889	$ 4,108	$ 3,767
Total long-term debt	1,808	1,744	1,306	1,313	1,003 *
Total Portland General Electric Company shareholders' equity	1,592	1,542	1,354	1,316	1,224
Common equity ratio	46.7%	46.9%	47.3%	50.0%	53.0%

* Includes preferred stock subject to mandatory redemption requirements.

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

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

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

- governmental policies and regulatory audits, investigations and actions, including those of the FERC and OPUC with respect to allowed rates of return, financings, electricity pricing and price structures, acquisition and disposal of facilities and other assets, construction and operation of plant facilities, transmission of electricity, recovery of power costs and capital investments, and current or prospective wholesale and retail competition;
- the 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 can affect customers' demand for power and could significantly affect PGE's ability and cost to procure adequate power and fuel supplies to serve its customers, and could increase the Company's costs to maintain its generating facilities and transmission and distribution systems;
- operational factors affecting PGE's power generation facilities, including forced outages, hydro and wind conditions, and disruption of fuel supply, which may cause the Company to incur replacement power costs and repair costs;
- the continuing effects of weak economies in the state of Oregon and the United States, including decreased demand for electricity, reduced revenue from sales of excess energy during periods of low wholesale market prices, impaired financial stability of vendors and service providers and elevated levels of uncollectible customer accounts;
- declines in wholesale power and natural gas prices, which could require the Company to issue additional letters of credit or post additional cash as collateral with counterparties pursuant to existing power and natural gas purchase agreements;

- capital market conditions, including access to capital, interest rate volatility, reductions in demand for investment-grade commercial paper and the availability and cost of capital, as well as changes in PGE's credit ratings, which could have an impact on the Company's cost of capital and its ability to access the capital markets to support requirements for working capital, construction costs, and the repayments of maturing debt;

- future laws, regulations, and proceedings that could increase the Company's costs or affect the operations of the Company's thermal generating plants by imposing requirements for additional pollution control equipment or significant emissions fees or taxes, particularly with respect to coal-fired generation facilities, in order to mitigate carbon dioxide, mercury and other gas emissions;

- wholesale prices for natural gas, coal, oil, and other fuels and the impact of such prices on the availability and price of wholesale power in the western United States;

- changes in residential, commercial, and industrial growth, and in demographic patterns, in PGE's service territory;

- the effectiveness of PGE's risk management policies and procedures and the creditworthiness of customers and counterparties;

- the failure to complete capital projects on schedule and within budget;

- the effects of Oregon law related to utility rate treatment of income taxes, which may result in earnings volatility and affect PGE's results of operations;

- declines in the fair value of equity securities held by defined benefit pension plans and other benefit plans, which could result in increased funding requirements for such plans;

- changes in, and compliance with, environmental and endangered species laws and policies;

- the effects of climate change, including changes in the environment that may affect energy costs or consumption, increase the Company's costs, or adversely affect its operations;

- new federal, state, and local laws that could have adverse effects on operating results;

- employee workforce factors, including aging, potential strikes, work stoppages, and transitions in senior management;

- general political, economic, and financial market conditions;

- natural disasters and other risks, such as earthquake, flood, drought, lightning, wind, and fire;

- financial or regulatory accounting principles or policies imposed by governing bodies; and

- acts of war or terrorism.

Any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by law, PGE undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for management to predict all such factors, nor can it assess the impact of any such factor on the business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement.

Overview

General Rate Case—On December 17, 2010, the OPUC issued a final order in PGE’s 2011 General Rate Case, which the Company filed with the OPUC on February 16, 2010 based on a 2011 test year. The OPUC approved an increase in PGE’s revenue of $65 million, which includes a reduction in NVPC of $35 million and represents an approximate 3.9% overall increase in customer prices, effective January 1, 2011. The increase in revenue primarily reflects the cost of infrastructure investments, including the recently completed Biglow Canyon wind farm project and relicensing of hydroelectric facilities on the Clackamas River. The Order also provides:

- A capital structure of 50% debt and 50% equity, with a return on equity of 10.0%, for an overall cost of capital of 8.033%;
- A narrowed and fixed deadband range of $15 million below to $30 million above baseline NVPC for the Company’s PCAM; and
- The continuation of the decoupling mechanism through December 31, 2013.

The OPUC removed four capital projects from the average rate base originally proposed in the rate case and approved the use of deferred accounting treatment for the costs, including a return on the Company's investment, of such projects, effective at the time they are placed in service. The recovery of any project in future customer prices will be subject to a regulated earnings test and approval by the OPUC. The OPUC also approved a tariff that would provide a mechanism for future consideration of price changes related to the recovery of the Boardman generating plant over a shortened operating life.

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

Customers and Demand—While customer growth has continued, the continued weak economy has resulted in a decline in retail energy deliveries. The relatively high unemployment rate in the state of Oregon has been indicative of economic activity in the state, which has had an impact on deliveries. Declines in retail energy deliveries are also attributable to energy efficiency and conservation efforts by retail customers, although the financial effects of such efforts are substantially mitigated by the decoupling mechanism. During 2010, the Company experienced an overall decrease of 3.1% in retail energy deliveries. On a weather adjusted basis, retail energy deliveries declined 1.4% compared to 2009. PGE estimates that approximately one-half of the decline is attributable to energy efficiency initiatives.

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The following table indicates deliveries, by customer class, including those to customers who chose to purchase their energy from an ESS, during the past two years:

	2010		2009		Increase/ (Decrease) in Energy Deliveries
	Average Number of Customers	Energy Deliveries *	Average Number of Customers	Energy Deliveries *	
Residential	717,719	7,452	714,377	7,901	(5.7)%
Commercial	102,282	7,277	101,221	7,559	(3.7)
Industrial	265	4,004	271	3,876	3.3
Total	820,266	18,733	815,869	19,336	(3.1)%

* In thousands of MWh.

Wholesale energy markets continue to feel the effect of the weak economy, with prices continuing to decline during 2010. As a result of both lower average prices and a reduction in energy sales, wholesale revenues declined 22% in 2010 compared to 2009.

The Company projects that retail energy deliveries will remain relatively flat in 2011 compared to weather adjusted retail energy deliveries for 2010. PGE anticipates that modest load growth will be offset by energy efficiency and conservation efforts.

As indicated below, average seasonally adjusted 2010 unemployment rates for the United States were higher than in 2009. The unemployment rates for both the state of Oregon and the Portland/Salem metropolitan area declined from 2009, but have exceeded the national average in both years. The majority of the Company's service territory lies within the Portland/Salem metropolitan area.

	United States	Oregon	Portland/ Salem
2010	9.6%	10.6%	10.5%
2009	9.3	11.4	11.0

The Oregon Department of Consumer and Business Services has issued a preliminary forecast that the average Oregon unemployment rate for 2011 will be approximately 9.6%.

Power Operations—PGE's generating plants performed well throughout 2010, with the availability of the plants PGE operates approximating 95%, compared to 89% in 2009 and 92% in 2008, and the availability of Colstrip (which PGE does not operate) approximating 95%, compared to 68% in 2009 and 97% in 2008. During 2009, both Colstrip and Boardman, the Company's coal-fired generating plants, experienced extended maintenance and repair outages, resulting in incremental replacement power costs of approximately $16 million.

Energy received from hydroelectric projects is a key component in meeting the Company's retail load requirement. Regional hydro conditions were below normal in both 2010 and 2009. Energy received from PGE-owned hydroelectric plants and under contracts from mid-Columbia projects decreased 8% in 2010 from 2009, and provided approximately 23% of the Company's retail load requirement in 2010 compared to 25% in 2009. Energy received from these resources fell short of projections in the Company's Annual Power Cost Update Tariff (AUT) by approximately 8% in 2010 and 2009. Such projections, which are finalized and filed with the OPUC in November each year, establish the power cost component of retail prices for the following calendar year. Any shortfall in hydro generation from that projected in the AUT is generally replaced with power from higher cost sources. Energy from hydro resources is expected to approximate normal for 2011.

In 2010, PGE completed the final phase of its largest renewable project, Biglow Canyon Wind Farm, at a total cost of $960 million, with 217 wind turbines in service and an installed capacity of approximately 450 MW. The project was completed in three separate phases as follows:

- Phase I—Completed in December 2007, at a total cost of $256 million, 76 wind turbines and an installed capacity of 125 MW;
- Phase II—Completed in August 2009, at a total cost of $319 million, 65 wind turbines and an installed capacity of 150 MW; and
- Phase III—Completed in August 2010, at a total cost of $385 million, 76 wind turbines and an installed capacity of 175 MW.

The addition of Biglow Canyon to PGE's generation portfolio was an important step in helping to meet Oregon's RPS. Energy received from wind resources, including power purchased from other wind farms, increased 43% in 2010 compared to 2009 and 11% in 2009 compared to 2008 and provided 6% of PGE's retail load requirement in 2010, compared to 4% in 2009 and 2008.

As wind resources become an increasing component of PGE's energy source mix, variations in the energy projected to be received from such sources and the actual energy received will have a greater impact on the Company's results from operations. Energy received from wind resources fell short of projections in 2010 by approximately 22%.

Capital Requirements and Financing—PGE's capital requirements and debt maturities in 2010 consisted of the following:

- Construction of Biglow Canyon Phase III, the smart meter project, and ongoing capital expenditures for the upgrade, replacement, and expansion of transmission, distribution and generation infrastructure. Capital expenditures were $450 million in 2010 and are expected to approximate $310 million in 2011; and
- The maturity of $186 million of long-term debt.

To fund these projects and debt maturities, the Company issued or remarketed a total of $249 million of long-term debt and generated $391 million of cash from operations in 2010. PGE expects cash from operations to be approximately $500 million in 2011. For further information, see the Liquidity and Debt and Equity Financings sections of this Item 7.

In November 2010, the OPUC acknowledged PGE's 2009 IRP, which was originally filed in November 2009, with an addendum filed in April 2010 updating the Company's plan with respect to Boardman. The 2009 IRP 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. In accordance with the acknowledgement and pursuant to the OPUC's competitive bidding guidelines, the Company will seek requests for proposals in 2011 for additional renewable and natural gas-fired resources. PGE plans to submit its own proposals for construction of the resources and if awarded the bids, would expect to need significant capital to fund the projects.

For additional information, see "Future Energy Resource Strategy" in the Power Supply section of Item 1.—"Business" and the Capital Requirements section in 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;
- An investigation of environmental matters at Portland Harbor; and
- Claims asserted by the Sierra Club as well as a notice of violation issued by the EPA in September 2010, alleging that the Company's operation of Boardman has violated various environmental regulations.

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."

Certain regulatory items impacted the Company's revenues, results of operations, or cash flows for 2010, as indicated below, and may 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. The following retail price adjustments, as approved by the OPUC, became effective on January 1, 2010:

- Power Costs—Pursuant to the AUT process, PGE annually files an estimate of its forecasted power costs, with new prices to become effective January 1st of 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. The AUT effective January 1, 2010 resulted in an estimated $68 million decrease in the Company's annual retail revenue requirement to reflect an expected decrease in power costs.
- Renewable Resource Costs—Pursuant to a renewable adjustment clause mechanism (RAC), PGE can recover in customer prices prudently incurred costs of renewable resources that are expected to be placed in service in the current year. The mechanism impacts results of operations only to the extent of providing a return on the Company's investments. It will, however, result in an increase in cash flows during future years to provide for the recovery of the initial capital expenditures for the renewable resources. The Company submits 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. Under this mechanism, PGE filed for recovery of its investments in Biglow Canyon Phase II and certain solar generating facilities in 2009, which resulted in an overall $42 million increase in annual retail revenues, effective January 1, 2010.

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

Rate actions pending as of January 1, 2011 include, but are not limited to, the following:

- Regulatory Treatment of Income Taxes (SB 408)—
  - During 2009, the Company recorded an estimated $13 million refund for the year ended December 31, 2009 that would normally be expected to be credited to customers over the twelve month period beginning June 1, 2011. In the second quarter of 2010, the OPUC revised the SB 408 administrative rules. The Company filed its annual SB 408 report for 2009 with the OPUC on October 15, 2010 based on the revised rules, reporting a $2 million refund to customers. Based on a stipulation subsequently reached with the OPUC staff and CUB, the Company has adjusted its estimate of the refund for 2009 to $8 million, which is reflected on its consolidated balance sheets as of December 31, 2010. The Industrial Customers of Northwest Utilities has filed objections to the stipulation claiming customer refunds totaling $61 million are required. In February 2011, PGE filed rebuttal

testimony to ICNU's objections, stating ICNU's claim is without merit, asking that the objections be denied, and requesting that the stipulation be approved. PGE will continue to evaluate the amount recorded as the 2009 filing proceeds through the OPUC review process. A ruling on the 2009 SB 408 report is expected by April 2011.

- In February 2011, the OPUC issued temporary rules that are expected to have an impact on the Company's SB 408 calculation for 2010. Due to the uncertainties of the regulatory process and the applicable rules, the Company has recorded no estimated amount for refund to, or collection from, customers for the year ended December 31, 2010. PGE estimates the collection from customers related to SB 408 for 2010 ranges from less than $1 million under the temporary rules to $33 million under the existing rules. Any amount ultimately recorded would be expected to be reflected in customer prices beginning June 1, 2012.

For further information regarding SB 408, see "*Regulatory treatment of income taxes*" in Note 6, Regulatory Assets and Liabilities, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

- Decoupling Mechanism—The decoupling mechanism provides for customer collection or refund if weather adjusted use per customer is less than or more than that approved in the Company's most recent general rate case.

  - In May 2010, the OPUC authorized the Company to refund to retail customers approximately $2.7 million related to the twelve month period ended January 31, 2010, as weather adjusted use per customer exceeded levels included in the 2009 General Rate Case. Revenues were adjusted during the corresponding period, while credits to customers began June 1, 2010 and will continue over a one-year period.

  - In 2010, the Company recorded an estimated collection of $8 million, as weather adjusted use per customer was less than levels included in the 2009 General Rate Case. Pending review and approval by the OPUC, any resulting collections from customers would be expected over a one-year period beginning June 1, 2011.

  - In the Company's 2011 General Rate Case, the OPUC extended the mechanism through 2013 with conversion to an annual calendar basis.

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 for 2010 compared to 2009, and for 2009 compared to 2008, which follow hereafter.

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

	Years Ended December 31,					
	2010		2009		2008	
	Amount	As % of Rev	Amount	As % of Rev	Amount	As % of Rev
Revenues, net	$ 1,783	100%	$ 1,804	100%	$ 1,745	100%
Purchased power and fuel	829	46	944	52	878	50
Gross margin	954	54	860	48	867	50
Operating expenses:						
Production and distribution	174	10	178	10	169	10
Administrative and other	186	11	179	10	190	11
Depreciation and amortization	238	13	211	12	208	12
Taxes other than income taxes	89	5	84	4	83	5
Total operating expenses	687	39	652	36	650	38
Income from operations	267	15	208	12	217	12
Other income (expense):						
Allowance for equity funds used during construction	13	1	18	1	9	1
Miscellaneous income (expense), net	4	—	3	—	(14)	(1)
Other income (expense), net	17	1	21	1	(5)	—
Interest expense	110	6	104	6	90	5
Income before income taxes	174	10	125	7	122	7
Income taxes	53	3	36	2	35	2
Net income	121	7	89	5	87	5
Less: net loss attributable to noncontrolling interests	(4)	—	(6)	—	—	—
Net income attributable to Portland General Electric Company	$ 125	7%	$ 95	5%	$ 87	5%

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

	Years Ended December 31,					
	2010		2009		2008	
	Amount	As % of Total	Amount	As % of Total	Amount	As % of Total
Revenues[1] (dollars in millions):						
Retail:						
Residential	$ 803	45%	$ 856	47%	$ 796	46%
Commercial	601	34	642	36	606	35
Industrial	221	12	166	9	150	8
Subtotal	1,625	91	1,664	92	1,552	89
Other accrued revenues, net	39	2	(7)	—	(44)	(2)
Total retail revenues	1,664	93	1,657	92	1,508	87
Wholesale revenues	87	5	112	6	195	11
Other operating revenues	32	2	35	2	42	2
Total revenues	$ 1,783	100%	$ 1,804	100%	$ 1,745	100%
Energy deliveries[2] (MWh in thousands):						
Retail:						
Residential	7,452	35%	7,901	36%	7,878	34%
Commercial	7,277	34	7,559	34	7,841	34
Industrial	4,004	19	3,876	17	4,275	18
Total retail energy deliveries	18,733	88	19,336	87	19,994	86
Wholesale energy deliveries	2,580	12	2,896	13	3,190	14
Total energy deliveries	21,313	100%	22,232	100%	23,184	100%
Average number of retail customers:						
Residential	717,719	88%	714,377	88%	710,991	88%
Commercial	102,282	12	101,221	12	100,061	12
Industrial	265	—	271	—	263	—
Total	820,266	100%	815,869	100%	811,315	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,					
	2010		2009		2008	
Sources of energy (MWh in thousands):						
Generation:						
Thermal:						
Coal	4,984	23%	3,760	18%	4,994	23%
Natural gas	4,460	21	4,500	21	4,460	20
Total thermal	9,444	44	8,260	39	9,454	43
Hydro	1,830	9	1,800	8	1,822	8
Wind	833	4	499	2	384	2
Total generation	12,107	57	10,559	49	11,660	53
Purchased power:						
Term purchases	3,984	19	6,145	29	5,241	24
Purchased hydro	2,417	11	2,801	13	3,037	14
Purchased wind	297	1	292	1	328	1
Spot purchases	2,618	12	1,641	8	1,648	8
Total purchased power	9,316	43	10,879	51	10,254	47
Total system load	21,423	100%	21,438	100%	21,914	100%
Less: wholesale sales	(2,580)		(2,896)		(3,190)	
Retail load requirement	18,843		18,542		18,724	

Net income attributable to Portland General Electric Company for the year ended December 31, 2010 was $125 million, or $1.66 per diluted share, compared to $95 million, or $1.31 per diluted share, for the year ended December 31, 2009. The $30 million, or 32%, increase in net income was primarily due to the effects of the following:

- Improved power supply operations, resulting from increases in plant availability along with lower natural gas prices relative to those included in the AUT. Additionally, during 2009 approximately $16 million of incremental replacement power costs were incurred to replace the output of both Colstrip and Boardman during extended maintenance and repair outages;

- A $17 million increase in Other accrued revenues related to SB 408, which is primarily the result of a $13 million refund to customers recorded in 2009 and a $4 million reduction to that amount recorded in 2010. For 2009, taxes authorized for collection in customer prices exceeded the amount paid by PGE, resulting in a future refund to customers. For the tax year 2010, no amount related to SB 408 was recorded; and

- An $18 million decrease in Purchased power and fuel expense, related to the write-off in 2009 of previously deferred excess replacement power costs associated with Boardman's forced outage from late 2005 to early 2006.

Operating results were also affected by a 3.1% decrease in retail energy deliveries, which was partially offset by the effects of the Company's decoupling mechanism.

Net income attributable to Portland General Electric Company for the year ended December 31, 2009 was $95 million, or $1.31 per diluted share, compared to $87 million, or $1.39 per diluted share, for the year ended

December 31, 2008. The $8 million, or 9%, increase in net income was primarily due to the following:

- A $33 million increase in Other accrued revenues due to the accrual of refunds due to customers in 2008 related to the Trojan regulatory proceeding;

- A $26 million increase in Other income related to changes in the fair value of the non-qualified benefit plan assets. In 2009, PGE recorded an increase in the fair value of these assets of $9 million compared to a $17 million decrease in 2008; partially offset by

- An $18 million increase in Purchased power and fuel due to the write-off in 2009 of deferred excess replacement power costs associated with Boardman's forced outage from 2005 to early 2006.

Operating results were also affected by an approximate 8% retail price increase, which became effective January 1, 2009; this was partially offset by a 3% decline in retail energy deliveries. Wholesale energy deliveries declined 9%, as power initially acquired to meet retail load was sold into a low-priced wholesale market. Reducing net income were increased power costs, resulting primarily from the impact of an 8% shortfall in energy projected from hydro resources and higher costs to replace the output of both Colstrip and Boardman during their extended maintenance and repair outages.

2010 Compared to 2009

Revenues decreased $21 million, or 1%, in 2010 compared to 2009 as a result of the net effect of the items discussed below.

Total retail revenues increased $7 million, or less than 1%, due primarily to the following largely offsetting items:

- A $25 million increase related to the volume of retail energy sold resulting from the net effect of:

  - A shift in the mix of customers purchasing their energy supplies from PGE, with a certain large industrial customer choosing to purchase its energy needs from PGE as opposed to purchasing its energy supplies from an ESS in 2009;
  - A 3.3% increase in deliveries to industrial customers due in part to improvement in the high technology sector and an increase in production by one large industrial customer; and
  - The addition of an average of 4,400 retail customers; partially offset by
  - A 5.7% decrease in residential deliveries and a 3.7% decrease in commercial deliveries primarily due to milder weather conditions during 2010 and the continued effects of a weak economy; and
  - The effects of energy efficiency programs on retail energy deliveries during 2010 relative to 2009.

- A $17 million increase related to SB 408, which is included in Other accrued revenues, resulting from an estimated $13 million customer refund recorded in 2009 along with a $4 million reversal of a portion of the 2009 refund recorded in 2010. As a result of the ongoing uncertainty around application of the rules, the Company elected to record no collection from customers for 2010, as would be the case under the temporary rules adopted in February 2011.

- A $15 million increase related to the decoupling mechanism, which is included in Other accrued revenues. In 2010, an estimated $8 million receivable from customers was recorded, resulting from lower weather adjusted use per customer than that approved in the 2009 General Rate Case, compared to a $7 million refund to customers recorded in 2009, resulting from higher weather adjusted use per customer than that approved in the 2009 General Rate Case;

- A $10 million increase resulting from a reduction in the transition adjustment credit provided to those commercial and industrial customers that purchase power from ESSs. Transition adjustment credits reflect the difference between the cost and market value of PGE's power supply, as provided by Oregon's electricity restructuring law;

- A $7 million increase related to the deferral of revenue requirements for Biglow Canyon, which is included in Other accrued revenues;

- A $5 million increase due to the reversal of a deferral for customer refunds related to the 2005 Oregon Corporate Tax Kicker, pursuant to an OPUC order issued in the third quarter 2010, which is included in Other accrued revenues; and

- A $72 million decrease related to a 4% decline in average retail price that resulted primarily from a decrease in net variable power costs, partially offset by increases for the recovery of Biglow Canyon Phase II and Selective Water Withdrawal capital projects.

Heating degree-days in 2010 decreased 5% compared to 2009, while cooling degree-days, which were 34% less than the 15-year average, decreased 50%. The following table indicates the number of heating and cooling degree-days for the periods presented, along with 15-year averages provided by the National Weather Service, as measured at Portland International Airport:

	Heating Degree-Days		**Cooling Degree-Days**	
	2010	**2009**	**2010**	**2009**
1st Quarter	1,629	2,022	—	—
2nd Quarter	861	578	18	90
3rd Quarter	117	63	296	537
4th Quarter	1,580	1,728	—	—
Full Year	4,187	4,391	314	627
15-year Full Year average	4,192	4,169	473	467

On a weather adjusted basis, retail energy deliveries decreased 1.4% in 2010 compared to 2009, with deliveries to residential and commercial customers decreasing by 2.5% and 2.2%, respectively, and deliveries to industrial customers increasing by 2.3%. PGE forecasts that total weather adjusted retail energy deliveries for 2011 will be flat relative to 2010.

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, and customer demand.

The continued weak economy over the past couple years has resulted in both lower wholesale energy sales volumes and prices due to a reduction in regional demand for electricity. In 2010, electricity demand from PGE's retail customers was less than projected, with excess power, initially acquired to meet retail load, sold into a relatively low-priced wholesale market. A portion of the excess volume was used to offset lower than projected hydro and wind production, thus reducing the volume available for resale into the wholesale energy market. Wholesale revenues in 2010 decreased $25 million, or 22%, from 2009 as a result of the following:

- A $13 million decrease related to a 12% decline in the average wholesale price the Company received, driven by lower electricity market prices; and

- A $12 million decrease due to an 11% decline in wholesale energy sales volume.

Other operating revenues decreased $3 million, or 9%, primarily due to a reduction in the sale of excess fuel oil in 2010 from the Company's Beaver generating plant. Such sales, which were $5 million and $8 million in 2010 and 2009, respectively, resulted in gains of $2 million in 2010 and $3 million in 2009.

Purchased power and fuel expense includes the cost of power purchased and fuel used to generate electricity to meet PGE's energy requirements, as well as the cost of settled electric and natural gas financial contracts. In 2010, Purchased power and fuel expense decreased $115 million, or 12%, from 2009, primarily due to an 11% decrease in average variable power cost, which was largely driven by the shift in the mix of energy sources. The average variable power cost was $38.68 per MWh in 2010 compared to $43.22 per MWh in 2009. In addition, an $18 million write-off of a regulatory asset in 2009, which is discussed below, contributed to the decrease in Purchased power and fuel expense.

The decrease in Purchased power and fuel expense consisted of:

- A $96 million decrease in the cost of purchased power, consisting of $84 million related to a 14% decrease in purchases and $12 million related to a 2% decrease in average cost. Increased purchases were required in 2009 to replace the output of Colstrip and Boardman during extended outages at these plants, resulting in incremental replacement power costs of approximately $16 million;

- An $18 million decrease related to the write-off in 2009 of a portion of a regulatory asset representing deferred excess replacement power costs associated with Boardman's forced outage from late 2005 to early 2006; and

- A $2 million decrease in the cost of generation, consisting of $52 million related to a 13% decrease in average cost, substantially offset by $50 million related to a 15% increase in generation, resulting primarily from a 33% increase in generation at Colstrip and Boardman. In 2009, both Colstrip and Boardman, the Company's coal-fired plants, had extended repair and maintenance outages. The decrease in average cost was primarily due to a 6% decrease in the average cost of natural gas-fired generation, which was driven by decreases in natural gas prices.

Pursuant to the PCAM, PGE can adjust future customer prices to reflect a portion of the difference between each year's forecasted NVPC included in prices (baseline NVPC) and actual NVPC, to the extent that such difference is outside of a pre-determined "deadband," subject to a regulated earnings test. In 2010, the Company's actual NVPC was $12 million below baseline NVPC, but within the established deadband range of $17 million below to $35 million above 2010 forecasted NVPC. Accordingly, no refund to customers was recorded in 2010. In 2009, PGE's actual NVPC was $22 million above the baseline, but within the established deadband of $15 million below to $29 million above 2009 forecasted NVPC. Accordingly, no collection from customers was recorded in 2009. Pursuant to the order received on PGE's 2011 General Rate Case, the deadband range for the PCAM was narrowed and fixed at $15 million below to $30 million above forecasted NVPC.

Energy received from PGE-owned hydroelectric projects and under contract from mid-Columbia projects were up 2% and down 14%, respectively, from 2009. Additionally, energy received from hydroelectric resources also fell short of projections included in the Company's AUT by approximately 8% in 2010 and 2009. Current forecasts indicate that regional hydro conditions in 2011 will approximate normal levels.

The following table indicates the forecast of the April-to-September 2011 runoff (issued February 17, 2011) compared to the actual runoffs for 2010 and 2009 (as a percentage of normal, as measured over the 30-year period from 1971 through 2000):

	Runoff as a Percent of Normal *		
Location	**2011 Forecast**	**2010 Actual**	**2009 Actual**
Columbia River at The Dalles, Oregon	98%	79%	85%
Mid-Columbia River at Grand Coulee, Washington	103	78	80
Clackamas River at Estacada, Oregon	89	124	122
Deschutes River at Moody, Oregon	92	104	92

* 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.

Gross margin was 54% in 2010 compared to 48% in 2009, an increase of 13%. Contributing to the increase was the impact of improved thermal operations, which more than offset the effect of lower retail energy sales during the year. Also contributing to the increase was the impact of SB 408 and the 2009 write-off of deferred power costs related to Boardman's outage, which had a negative impact on Gross margin in that year.

Production and distribution expense decreased $4 million, or 2%, in 2010 compared to 2009, primarily due to the net effect of the following:

- A $6 million decrease related to certain capital costs expensed in 2009 for the Selective Water Withdrawal project, pursuant to a stipulation with the OPUC;
- A $5 million decrease in repair and restoration expenses, related primarily to 2009 wind storms;
- A $5 million decrease in operating and maintenance expenses at Boardman, Colstrip Unit 4, and Coyote Springs;
- A $2 million decrease related to a reserve established in 2009 for the cost of certain environmental remediation activities;
- A $7 million increase related to the deferral of certain plant maintenance costs at Boardman, Beaver, and Colstrip in 2009. As authorized by the OPUC in PGE's 2009 General Rate Case, certain maintenance costs that exceed those covered in current prices are deferred and amortized over ten years, beginning in 2009; and
- A $7 million increase in operating and maintenance expenses related to the Company's distribution system and Biglow Canyon.

Administrative and other expense increased $7 million, or 4%, in 2010 compared to 2009, primarily due to the net effect of the following:

- A $5 million increase in incentive compensation, related to improved corporate financial and operating performance in 2010;
- A $5 million increase in legal expenses and reserves for asserted claims;
- A $5 million increase in employee benefit expenses, related primarily to higher pension and health care costs;
- A $3 million decrease in the provision for uncollectible accounts, due to an improvement in the current status of customer accounts;
- A $3 million decrease in insurance costs and in customer support expenses, including reductions related to implementation of the smart meter project; and
- A $2 million decrease related to OPUC revenue fees (fully offset in Retail revenues).

Depreciation and amortization expense increased $27 million, or 13%, in 2010 compared to 2009, due largely to the net effect of the following:

- A $23 million increase in depreciation related to Biglow Canyon Phases II and III, the smart meter project, the Selective Water Withdrawal project, and other capital additions in late 2009 and in 2010;
- A $4 million increase related to a 2009 reduction in the deferral of certain Oregon tax credits for future ratemaking treatment, as the Company was unable to utilize such credits (offset in Income taxes);
- A $2 million increase related to the amortization of certain regulatory assets and liabilities; and
- A $1 million decrease related to lower impairment losses recognized in 2010 compared to 2009 on photovoltaic solar power facilities, the majority of which was allocated to noncontrolling interests through the Net loss attributable to the noncontrolling interests. For additional information, see Note 16, Variable Interest Entities, in the Notes to Consolidated Financial Statements in Item 8.—“Financial Statements and Supplementary Data.”

Taxes other than income taxes increased $5 million, or 6%, in 2010 compared to 2009, due primarily to higher property and payroll taxes as well as higher city franchise fees.

Other income, net was $17 million in 2010 compared to $21 million in 2009. The decrease is primarily due to the net effect of the following:

- A $4 million decrease in the allowance for equity funds used during construction, as a result of lower construction work in progress balances during 2010, related primarily to the completion of Biglow Canyon Phases II and III;
- A $4 million decrease in income from non-qualified benefit plan trust assets, resulting from a $5 million increase in the fair value of the plan assets in 2010 compared to a $9 million increase in 2009; and
- A $4 million increase resulting from reductions in corporate donations, sponsorships, and certain non-utility activities, partially offset by lower interest income on regulatory assets.

Interest expense increased $6 million, or 6%, in 2010 compared to 2009 primarily due to the net effect of the following:

- An $8 million increase resulting from a higher average long-term debt balance during 2010 compared to 2009, related primarily to issuances of first mortgage bonds in late 2009 and in 2010 to fund the construction of new generating facilities. In 2010, the average balance of long-term debt outstanding was $1,776 million compared to $1,525 million in 2009;

- A $3 million increase resulting from a decrease in the allowance for funds used during construction, related primarily to the construction of Biglow Canyon Phases II and III; and

- A $5 million decrease in interest on regulatory liabilities, consisting primarily of customer refunds related to the Trojan regulatory proceeding and the Company’s PCAM.

Income taxes increased $17 million, or 47%, in 2010, compared to 2009, primarily due to higher income before taxes in 2010. The effective tax rates (30.3% and 28.8% for 2010 and 2009, respectively) differ from the federal statutory rate primarily due to benefits from federal wind production tax credits (PTCs) and state tax credits. An increase in PTCs, related to increased production from the completed Biglow Canyon wind project, was largely offset by an increase in the state income tax rate and a reduction in state tax credits.

Net loss attributable to noncontrolling interests of $4 million in 2010 and $6 million in 2009 represents the noncontrolling interests’ portion of the net loss of PGE’s less-than-wholly-owned subsidiaries, the majority of which consists of the impairment losses recognized on the photovoltaic solar power facilities, discussed previously in Depreciation and amortization.

2009 Compared to 2008

Revenues increased $59 million, or 3%, in 2009 compared to 2008 as a result of the net effect of the items discussed below.

Total retail revenues increased $149 million, or 10%, due primarily to net effect of the following:

- A $125 million increase resulting from higher average prices, driven primarily by OPUC-approved price increases in PGE’s 2009 General Rate Case, which became effective January 1, 2009;

- A $33 million increase resulting from the accrual of refunds to customers related to the Trojan regulatory proceeding, which is reflected as a reduction to Other accrued revenues in 2008;

- An $11 million increase related to cost recovery of Biglow Canyon Phase II, included in Other accrued revenues;

- A $10 million increase resulting from a reduction in transition adjustment credits provided to those commercial and industrial customers that purchase power from ESSs. Such credits are based on the difference between the cost and market value of PGE’s power supply;

- A $14 million decrease driven by a decline in retail energy deliveries, with the impact of the continued economic slowdown in 2009 only partially offset by an increase in the average number of customers served during the year. Economic shutdowns by some large industrial customers contributed to a 9.3% decrease in energy deliveries to industrial customers;

- A $10 million decrease in supplemental tariffs, which is fully offset in Depreciation and amortization expense; and

- A $7 million decrease (included in Other accrued revenues) related to the decoupling mechanism, which went into effect on February 1, 2009.

Heating degree-days in 2009 decreased 4.2% compared to 2008, while cooling degree-days, which were 34% greater than the 15-year average, increased 32%. The following table indicates the number of heating and cooling degree-days for the periods presented, along with 15-year averages provided by the National Weather Service, as measured at Portland International Airport:

	Heating Degree-Days		Cooling Degree-Days	
	2009	2008	2009	2008
1st Quarter	2,022	1,981	—	—
2nd Quarter	578	860	90	98
3rd Quarter	63	80	537	376
4th Quarter	1,728	1,661	—	—
Full Year	4,391	4,582	627	474
15-year Full Year average	4,169	4,169	467	467

On a weather adjusted basis, retail energy deliveries decreased 2.6% in 2009 compared to 2008, with deliveries to residential, commercial, and industrial customers increasing (decreasing) by 0.7%, (2.8)%, and (8.4)%, respectively.

Wholesale revenues in 2009 decreased $83 million, or 43%, from 2008 as a result of the following:

- A $65 million decrease related to a 37% decline in average wholesale prices, driven by lower natural gas and electricity prices; and

- An $18 million decrease due to a 9% decline in wholesale energy sales volume.

Other operating revenues decreased $7 million, or 17%, primarily due to fuel oil sales of $8 million in 2009 from the Company's Beaver generating plant compared to $15 million in 2008. Such sales resulted in realized gains of $3 million in 2009 and $11 million in 2008.

The national economic downturn resulted in both lower wholesale energy sales and prices due to a reduction in both actual and projected demand for electricity. In 2009, electricity demand by PGE customers was less than projected, with excess power, initially acquired to meet retail load, sold into a low-priced wholesale market. Also contributing to lower wholesale energy sales was the combined effect of the Company's requirement to replace the output of Colstrip and Boardman, during the extended outages at these plants, and lower than projected hydro production.

Purchased power and fuel expense increased $66 million, or 8%, for 2009 from 2008, primarily due to $69 million related to an 8% increase in average variable power cost and $18 million related to the write-off of a portion of a regulatory asset representing deferred excess replacement power costs associated with Boardman's forced outage from late 2005 to early 2006, partially offset by $20 million related to a 2% decrease in total system load. The average variable power cost of PGE's total system load was $43.22 and $40.01 per MWh in 2009 and 2008, respectively, an increase of 8%. The average variable power cost for 2009 excludes the effect of the write-off of the regulatory asset discussed below.

The increase in Purchased power and fuel consisted of:

- A $63 million increase in the cost of purchased power, resulting from a 6% increase in both purchases and average cost. Increased purchases were required to replace the output of Colstrip and Boardman during extended maintenance and repair outages at these plants in 2009, resulting in incremental replacement power costs of approximately $16 million. A decrease in energy received under contracts with mid-Columbia hydroelectric projects contributed to the increase in the average cost;

- An $18 million increase related to the write-off of a portion of a regulatory asset consisting of deferred excess replacement power costs associated with Boardman's forced outage discussed above; partially offset by

- A $14 million decrease in the cost of thermal production, resulting primarily from a 25% decrease in generation at Colstrip and Boardman as a result of their extended outages and a 2% decrease in the average cost of natural gas-fired generation. These decreases were partially offset by the impact of a 13% increase in the average cost of coal-fired generation and a 1% decrease in PGE hydro production.

Regional hydro conditions were below normal in 2009. Energy received from PGE-owned hydroelectric plants and under contracts from mid-Columbia projects were down 1% and 8%, respectively, from 2008.

Gross margin was 48% in 2009 compared to 50% in 2008, a decrease of 4%. Contributing to the decrease was the impact of a reduction in retail energy sales, decreases in both thermal and hydroelectric generation, and the write-off of deferred power costs related to Boardman's outage. Substantially offsetting these items was the impact of a $33 million provision for refund to customers, recorded in 2008, related to the Trojan regulatory proceeding.

Production and distribution expense increased $9 million, or 5%, in 2009 compared to 2008, due to the net effect of the following:

- A $6 million increase related to certain capital costs expensed for the Selective Water Withdrawal project, pursuant to a stipulation with the OPUC;

- A $4 million increase in maintenance costs at Colstrip Unit 4, consisting of $3 million related to an extended overhaul and $1 million for the repair of damaged turbine rotors;

- A $4 million increase related to cost escalation provisions in Coyote Spring's long-term service agreement (fully offset in Depreciation and amortization expense);

- A $3 million increase for repair and restoration activities, related primarily to 2009 wind storms;

- A $6 million decrease related to the deferral of certain plant maintenance costs at Boardman, Beaver, and Colstrip. As authorized by the OPUC in PGE's 2009 General Rate Case, certain maintenance costs that exceed those covered in current prices are deferred and amortized over ten years, beginning in 2009; and

- A $2 million decrease in planned maintenance outage expenses at Boardman.

Administrative and other expense decreased $11 million, or 6%, in 2009 compared to 2008, due to the following:

- An $8 million decrease in incentive compensation, due to changes in the provisions of officer and employee plans that resulted in reduced awards based on 2009 performance;

- A $5 million decrease related to both the settlement of a legal claim in 2008 and lower legal and general support expenses in 2009;

- A $3 million decrease in customer support expenses, including reductions related to implementation of the smart meter project; and

- A $5 million increase in employee benefit expenses, related primarily to pension and health care costs.

Depreciation and amortization expense increased $3 million, or 1%, in 2009 compared to 2008, due largely to the net effect of the following:

- A $14 million increase in depreciation related to Biglow Canyon Phase II, the smart meter project, and other capital additions in 2009;
- A $5 million increase related to impairment losses recognized on photovoltaic solar power facilities, the majority of which was allocated to noncontrolling interests through the Net loss attributable to the noncontrolling interests. 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;"
- A $10 million decrease related to the 2008 recovery of certain regulatory assets (fully offset in Retail revenues);
- A $4 million decrease related to the regulatory deferral of certain plant maintenance expenses at Coyote Springs (fully offset in Production and distribution expense); and
- A $3 million decrease resulting from a reduction in the deferral of certain Oregon tax credits for future ratemaking treatment, as the Company was unable to utilize such credits (offset in Income taxes).

Taxes other than income taxes increased $1 million, or 1%, in 2009 compared to 2008, due primarily to higher franchise fees resulting from increased retail revenues.

Other income (expense), net was $21 million in 2009 compared to $(5) million in 2008. The change was due primarily to the net effect of the following:

- A $26 million increase in income from non-qualified benefit plan trust assets, resulting from a $9 million increase in the fair value of the plan assets during 2009 compared to a $17 million decrease in 2008;
- An $8 million increase in the allowance for equity funds used during construction, as a result of higher construction work in progress balances during 2009, related primarily to Biglow Canyon Phases II and III; and
- A $7 million decrease in miscellaneous income, resulting primarily from lower interest on regulatory assets and money market account balances.

Interest expense increased $14 million, or 16%, in 2009 compared to 2008, primarily due to the net effect of the following:

- An $18 million increase resulting from a higher average long-term debt balance during 2009 compared to 2008, related primarily to issuances of first mortgage bonds in 2009 to fund the construction of new generating facilities. In 2009, the average balance of long-term debt outstanding was $1,525 million compared to $1,310 million in 2008;
- A $2 million increase in credit facility fees; and
- A $6 million decrease resulting from an increase in the allowance for funds used during construction, related primarily to the construction of Biglow Canyon Phases II and III.

Income taxes increased $1 million, or 3%, in 2009 compared to 2008, with an effective tax rate of 28.8% in 2009, compared to the 28.4% rate in 2008. In January 2010, an increase in the state corporate tax rate became effective, retroactive to January 1, 2009. The increase in the state corporate tax rate is substantially offset by the effects of SB 408.

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Net loss attributable to noncontrolling interests of $6 million in 2009 represents the noncontrolling interests' portion of the net loss of PGE's less-than-wholly-owned subsidiaries, the majority of which consists of the 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 business plan as currently scheduled." in Item 1A.—"Risk Factors."

Capital Requirements

The following table indicates actual capital expenditures for 2010 and future debt maturities and projected cash requirements for 2011 through 2015 for projects that the Board of Directors has approved (in millions):

	Years Ending December 31,					
	2010	2011	2012	2013	2014	2015
Ongoing capital expenditures	$ 211	$ 251	$ 219	$ 215	$ 235	$ 256
Biglow Canyon Phase III	166	—	—	—	—	—
Hydro licensing and construction	8	31	21	13	25	27
Smart meter project	45	4	—	—	—	—
Boardman emissions controls (1)	5	24	1	13	3	—
Total capital expenditures	$ 435 (2)	$ 310	$ 241	$ 241	$ 263	$ 283
Preliminary engineering	$ 8	$ 20	$ 2	$ —	$ —	$ —
Long-term debt maturities	$ 186	$ 10	$ 100	$ 100	$ 63	$ 70

(1) Represents 80% of estimated total costs based on installation of controls to meet regulatory requirements. In 1985, PGE sold an undivided 15% interest in Boardman to a third party, reducing the Company's ownership interest from 80% to 65%. The purchaser has certain rights to participate in the financing of the portion of the total capital cost attributable to its interest. If the purchaser does not exercise its rights to finance the portion of the total cost attributable to its interest, PGE's share of the total cost for the emissions controls at Boardman is expected to be 80%. PGE would seek to recover the incremental investment in future customer prices, although there can be no guarantee such recovery would be granted.

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

The following provides information regarding the items presented in the table above.

Ongoing capital expenditures—Consists of upgrades to and replacement of transmission, distribution and generation infrastructure, as well as new customer connections.

Biglow Canyon Phase III—With an installed capacity of 175 MW, Phase III was completed and placed in service in August 2010, at a total cost of $385 million, including $22 million of AFDC.

Hydro licensing and construction—In December 2010, the FERC issued a new 40-year operating license for the Company's Clackamas River project. Capital spending requirements reflected in the table above relate primarily to modifications to the facilities to enhance fish passage and survival, as required by conditions contained in the license.

Smart meter project—The Company has finalized installation of approximately 825,000 new customer smart meters as of December 31, 2010. This project enables two-way, remote communication with customer meters and is expected to provide improved services, operational efficiencies, and a reduction in future operating expenses. The total capital cost of the project is estimated at $140 million to $145 million, excluding AFDC.

Boardman emissions controls—In accordance with federal regional haze rules, PGE submitted an initial analysis and control plan for Boardman to the DEQ in 2007 after it was determined that Boardman would be subject to a Regional Haze Best Available Retrofit Technology (BART) Determination, as required under the Clean Air Act.

The OEQC adopted a rule in June 2009 (2009 Rule) that would have required the installation of controls at Boardman in three phases, with estimated completion by July 1, 2017. In April 2010, the Company petitioned the OEQC to reconsider the 2009 Rule. Following an extensive public process, the OEQC approved revised BART rules during 2010. The revised rules: i) provide for coal-fired operation at Boardman to cease no later than December 31, 2020; ii) reduce the capital expenditures that will be required for emissions controls at Boardman; and iii) repeal the 2009 Rule. The revised rules have been submitted to the EPA for consideration and approval.

Under this plan, the total cost of the emission controls is estimated at approximately $60 million (100% of total costs, excluding AFDC), including approximately $7 million required to eliminate 90% of the mercury emissions as required under a separate rule making process, and is reflected in the table above.

Preliminary engineering—Preliminary engineering costs consist of expenditures for preliminary surveys, plans, and investigations made for the purpose of determining the feasibility of utility projects under consideration, as indicated below. If PGE moves forward with construction of the project, such costs are reclassified to Electric utility plant. If the capital project is abandoned, such costs are expensed 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.

Integrated resource plan—Estimated future expenditures related to the addition or modification of any energy resources and a significant new high voltage transmission project, pursuant to PGE's IRP are not included in the table above. These include:

- The construction of the Cascade Crossing Transmission Project at an estimated total cost (in 2011 dollars) of $800 million to $1.0 billion, with an estimated in-service date of 2015. The Company is currently in discussions with potential partners in this project; and

- Other projects included in the Company's IRP. The timing and total cost of any project, which would be subject to a formal bidding process, are not certain at this time.

Certain costs related to investigating the potential construction of these facilities are currently included in *Preliminary engineering* in the table above.

For additional information, see "Future Energy Resource Strategy" in the Power Supply and Transmission and Distribution sections of Item 1.—"Business."

Liquidity

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

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

	Years Ended December 31,		
	2010	**2009**	**2008**
Cash and cash equivalents, beginning of year	$ 31	$ 10	$ 73
Net cash provided by (used in):			
Operating activities	391	386	183
Investing activities	(430)	(700)	(382)
Financing activities	12	335	136
Net change in cash and cash equivalents	(27)	21	(63)
Cash and cash equivalents, end of year	$ 4	$ 31	$ 10

2010 Compared to 2009

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 $5 million increase in cash provided by operating activities in 2010 compared to 2009 was largely due to an increase in net income after the consideration of noncash items, the receipt of an income tax refund in 2010 that was accrued in 2009, and customer refunds in 2009 related to the Trojan regulatory proceeding. These increases were offset by an increase in margin deposit requirements pursuant to power and natural gas purchase agreements, driven primarily by decreases in the forward market prices of power and natural gas, and a $30 million contribution in 2010 to the pension plan.

A significant portion of cash provided by operations consists of recovery in customer prices of non-cash charges for depreciation and amortization. The Company estimates that such charges will approximate $220 million in 2011. Combined with all other sources, cash provided by operations is estimated to be approximately $500 million in 2011. This estimate includes the return of $33 million of margin deposits held by certain wholesale customers and brokers as of December 31, 2010, and is based on both the timing of contract settlements and projected energy prices. The remaining $247 million in estimated cash flows from operations in 2011 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. Capital expenditures decreased $246 million in 2010 compared to 2009 due to decreased construction costs related to the Biglow Canyon wind farm and smart meter projects, as well as a decrease in construction costs related to the Selective Water Withdrawal project, which was completed in January 2010. Additionally, during 2010, a $19 million distribution was made from the Nuclear decommissioning trust to PGE as a result of an OPUC order issued in connection with the deferral of Boardman power costs. For additional information, see Note 6, Regulatory Assets and Liabilities, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

The Company plans approximately $310 million of capital expenditures in 2011 related to hydro licensing and construction, Boardman emissions controls and ongoing capital expenditures related to upgrades to and replacement of transmission, distribution and generation infrastructure. PGE plans to fund the 2011 capital expenditures with the cash expected to be generated from operations during 2011, as discussed above. For additional information, see the

Capital Requirements 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 2010, net cash provided by financing activities primarily consisted of proceeds received from the issuance or remarketing of long-term debt of $249 million and net issuances of commercial paper of $19 million, partially offset by the repayment of long-term debt of $186 million and the payment of dividends of $78 million. During 2009, net cash provided by financing activities consisted of the issuances of long-term debt of $580 million and common stock of $170 million, partially offset by the repayment of long-term debt of $142 million, net repayment of amounts due under revolving lines of credit of $131 million, the payment of dividends of $72 million and net maturities of commercial paper of $65 million.

2009 Compared to 2008

Cash Flows from Operating Activities—The $203 million increase in cash provided by operating activities in 2009 compared to 2008 was primarily due to a decrease in margin deposits required under power and natural gas purchase agreements, driven by increases in the forward market prices of power and natural gas, partially offset by customer refunds related to the Trojan regulatory proceeding. The $60 million increase in the change of Deferred income taxes, a non-cash charge included in Net income, is related primarily to the Company's price risk management activities.

Cash Flows from Investing Activities—Capital expenditures increased $313 million in 2009 from 2008 primarily due to increased construction costs related to Biglow Canyon Phases II and III and the smart meter project, partially offset by a decrease in construction costs related to the Selective Water Withdrawal project.

Cash Flows from Financing Activities—During 2009, net cash provided by financing activities primarily consisted of proceeds received from the issuance of long-term debt of $580 million and net proceeds received from the issuance of common stock for $170 million, partially offset by the net repayment of short-term debt and commercial paper of $203 million, the repayment of long-term debt of $142 million and the payment of dividends of $72 million. Financing activities also included the receipt of $7 million in capital contributions from the noncontrolling interests in two solar projects. During 2008, net cash provided by financing activities consisted of the net issuance of short-term borrowings and commercial paper of $203 million and the issuance of long-term debt of $50 million, partially offset by the repayment of long-term debt of $56 million and the payment of dividends of $60 million.

Dividends on Common Stock

The following table indicates common stock dividends declared in 2010:

Declaration Date	Record Date	Payment Date	Declared Per Common Share
February 17, 2010	March 25, 2010	April 15, 2010	$ 0.255
May 13, 2010	June 25, 2010	July 15, 2010	0.260
August 3, 2010	September 24, 2010	October 15, 2010	0.260
October 27, 2010	December 27, 2010	January 17, 2011	0.260

While the Company expects to pay regular quarterly dividends on its common stock, the declaration of any dividends is at the discretion of the Company's Board of Directors. The amount of any dividend declaration will depend upon factors that the Board of Directors deem 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 16, 2011, the Board of Directors declared a dividend of $0.26 per share of common stock to stockholders of record on March 25, 2011, payable on or before April 15, 2011.

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	Stable	Stable

In June 2010, Moody's revised its outlook of PGE from 'positive' to 'stable' due to decreased energy demand as a result of the weak economy, customer conservation and mild weather conditions. In February 2011, S&P reaffirmed its current credit ratings and outlook for the Company, citing stable regulated operations, impacts of the economy on load growth, and current capital spending levels.

The Company could be subject to requests by certain of its wholesale, commodity and related transmission counterparties to post additional performance assurance collateral in connection with its price risk management activities should Moody's and/or S&P reduce their credit rating on PGE's unsecured debt to below investment grade. The performance assurance collateral can be in the form of cash deposits or letters of credit, depending on the terms of the underlying agreements, and are based on the contract terms and commodity prices and can vary from period to period. These cash deposits are classified as Margin deposits in PGE's consolidated balance sheet, while any letters of credit issued are not reflected in the Company's consolidated balance sheet. As of December 31, 2010, PGE had posted approximately $263 million of collateral with these counterparties, consisting of $83 million in cash and $180 million in letters of credit, $31 million of which is related to master netting agreements. Provided that market prices remain unchanged, the Company anticipates that approximately 69% of the posted collateral would no longer be required by the end of 2011 as the related contracts are settled, with another 22% expected to roll off by the end of 2012. Based on the Company's energy portfolio, estimates of energy market prices, and the level of collateral outstanding as of December 31, 2010, the approximate amount of additional collateral that could be requested upon a single agency downgrade to below investment grade is approximately $110 million and decreases to approximately $33 million by December 31, 2011. The amount of additional collateral that could be requested upon a dual agency downgrade to below investment grade is approximately $223 million and decreases to approximately $74 million by December 31, 2011.

PGE's financing arrangements do not contain ratings triggers that would result in the acceleration of required interest and principal payments in the event of a ratings downgrade.

The issuance of additional First Mortgage Bonds requires that PGE meet 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, 2010, under the most restrictive issuance test in the Indenture of Mortgage and Deed of Trust, the Company could have issued up to approximately $461 million of additional first mortgage bonds. Any additional 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 on the basis of property additions, bond credits, and/or deposits of cash.

PGE's credit facilities contain customary covenants and credit provisions, including a requirement that limits consolidated indebtedness, as defined in the credit agreements, to 65% of total capitalization (debt ratio). As of December 31, 2010, the Company's debt ratio, as calculated under the credit agreements, was 53.4%.

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. PGE currently expects to seek a $100 million increase in its revolving credit capacity and may issue debt and equity securities to fund certain projects in future years.

Short-term Debt. PGE has approval from the FERC to issue short-term debt up to a total of $750 million through February 6, 2012 and currently has the following unsecured revolving credit facilities:

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

These credit facilities supplement operating cash flows and provide a primary source of liquidity. Pursuant to the individual terms of the agreements, the credit facilities may be used for general corporate purposes and as a backup for commercial paper borrowings. The $370 million and $30 million credit facilities also permit the issuance of standby letters of credit. As of December 31, 2010, PGE had no borrowings outstanding under the credit facilities, with $19 million of commercial paper outstanding and $209 million of letters of credit issued. As of December 31, 2010, the aggregate unused available credit under the credit facilities was $372 million.

Long-term Debt. In 2010, PGE had the following long-term debt transactions:

- In January, issued $70 million of 3.46% Series First Mortgage Bonds, which mature January 2015;
- In March, remarketed $121 million of pollution control revenue bonds at 5.0%, which mature 2033;
- In March, repaid $149 million of 7.875% unsecured notes;
- In April and June, repaid $20 million and $17 million, respectively, of 4.8% Port of St. Helens Pollution Control Revenue Bonds; and
- In June, issued $58 million of 3.81% Series First Mortgage Bonds, which mature June 2017.

As of December 31, 2010, PGE owns $21 million of its Pollution Control Revenue Bonds, which may be remarketed at a later date, at the Company's option and dependent on capital market conditions, through 2033. As of December 31, 2010, total long-term debt outstanding was $1,808 million.

In January 2011, PGE redeemed and retired the Port of St. Helens pollution control revenue bonds outstanding in the amount of $10 million.

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 46.7% and 46.9% as of December 31, 2010 and 2009, respectively.

Contractual Obligations and Commercial Commitments

The following indicates PGE's contractual obligations as of December 31, 2010 (in millions):

	Payments Due						
	2011	**2012**	**2013**	**2014**	**2015**	**There-after**	**Total**
Long-term debt	$ 10	$ 100	$ 100	$ 63	$ 70	$ 1,465	$ 1,808
Interest on long-term debt (1)	104	103	96	90	87	1,189	1,669
Capital and other purchase commitments	136	15	13	6	6	26	202
Purchased power and fuel:							
Electricity purchases	111	70	69	66	65	416	797
Capacity contracts	21	20	20	20	19	19	119
Public Utility Districts	9	7	8	8	8	49	89
Natural gas	69	25	20	17	16	16	163
Coal and transportation	21	4	3	—	—	—	28
Pension plan contributions (2)	—	9	18	4	—	—	31
Operating leases	10	10	10	10	10	202	252
Total	$ 491	$ 363	$ 357	$ 284	$ 281	$ 3,382	$ 5,158

(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, 2010.

(2) Contributions to the Company's pension plan are estimated based on numerous plan assumptions, including plan funded status. A return on plan assets of 8.5% was used for all years, with the following discount rates: 6.26% for 2011; 5.71% for 2012; 5.91% for 2013; 6.25% for 2014; and 6.5% for 2015 and thereafter.

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 four hydroelectric projects (the Rocky Reach, 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 Rocky Reach and Wells projects, 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 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

General - 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 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 could have a material impact on the Company's results of operations and financial position.

Regulatory Treatment of Income Taxes - A 2005 Oregon law, SB 408, attempts to match estimates of income taxes collected in revenues with the amount of income taxes paid to governmental entities by investor-owned electric and natural gas utilities or their consolidated group. Application of the provisions of SB 408 can result in unusual outcomes and can have a material effect on the Company's results of operations. Further, changes in administrative rules, as well as differences in their interpretation, have made it difficult to estimate the impact of SB 408 on PGE's operating results.

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 material loss contingency is accrued and disclosed 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 minimize net variable power costs for retail customers. The Company utilizes derivative instruments, which may include forward, swap, and option contracts for electricity, natural gas, oil, and foreign currency, and futures contracts for natural gas and oil, in its retail electric utility activities to manage its exposure to commodity price risk and foreign exchange rate risk, mitigate the effects of market fluctuations, and minimize net power costs for service to its retail customers. These derivative instruments are recorded at fair value, or "marked-to-market," in PGE's consolidated financial statements.

Marking a contract to market consists of reevaluating the market value at the end of each reporting period for the entire term of the contract and recording any change in value (difference between the contract price and current market price) in either Net income or Other comprehensive income for the period. Valuation of these financial instruments reflects management's best estimates of market prices, including closing New York Mercantile Exchange (NYMEX) and over-the-counter quotations, time value of money, and volatility factors underlying the commitments.

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 price 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, NYMEX, and other sources, and are validated using independent publications. Estimates used in creating forward price curves can change with market conditions and can be materially affected by unpredictable factors such as weather and the economy. The difference between PGE's forward price curves and four independently published price curves averages 1%. The difference at any single location, delivery date and commodity is less than 5%.

For purchases and sales of forward physical or financial contracts, the mark-to-market value is the present value of the difference between PGE's contracted price and the forward price multiplied by the total quantity of the contract. For option contracts, a theoretical value is computed using standard financial models that utilize price volatility, price correlation, time to expiration, interest rate and price curves. The mark-to-market of these options includes the premium paid or received as a component of the theoretical value.

Pension Plan

Pension expense is dependent on several assumptions used in the actuarial valuation of the plan. Primary assumptions 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 based on assumptions regarding rates of return on long-term high quality bonds. Assumptions regarding the expected rate of return on plan assets are based on historical and projected average rates of return for current asset classes in the plan investment portfolio. The expected rate of return reflects expected future returns for the portfolio, and was used in determining net periodic pension expense for the year.

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 would have increased 2010 net periodic pension expense by approximately $1.2 million. A 0.25% reduction in the discount rate would have increased 2010 net periodic pension expense by approximately $1.4 million.

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, money market funds and fixed income securities held by the Nuclear decommissioning 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 market 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, which provides quarterly reports to the Finance Committee of PGE's Board of Directors, 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 recommends for adoption policies and procedures, establishes risk limits subject to PGE Board approval, and monitors compliance with policies, procedures, and limits on a regular basis through reports and meetings.

Commodity Price Risk

PGE's primary business is to provide electricity to its retail customers. The Company participates in the wholesale marketplace in order to balance its supply of power to meet the needs of its retail customers, manage risk, and administer its current long-term wholesale contracts. 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; swap 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 options and futures contracts to mitigate risk that arises from market fluctuations of commodity prices. PGE does not engage in trading activities for non-retail purposes.

PGE actively manages its risk to ensure compliance with its risk management policies. The Company monitors open commodity positions in its energy portfolio that extend over the next 24 months using a value at risk methodology, which measures the potential impact of market movements over a one-day holding period using a variance/covariance approach at a 95% confidence interval. The portfolio is modeled using net open power and natural gas positions, with power averaged over peak and off-peak periods by month, and includes all financial and physical positions for the next 24 months, including estimates of retail load and plant generation. The risk factors include commodity prices for power and natural gas at various locations and do not include volumetric variability. Based on this methodology, the average, high, and low value at risk on the Company's energy portfolio in 2010 were $2.2 million, $6.0 million, and $1.0 million, respectively and in 2009 were $2.7 million, $5.1 million, and $1.2 million, respectively. PGE's value at risk measurement is performed prior to the effects of regulation as discussed below.

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 mitigates 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, 2010, a 10% change in the value of the Canadian dollar would result in an immaterial change in income before income taxes for transactions that will settle over the next 12 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, 2010, PGE had no borrowings outstanding under its revolving credit facilities and $19 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, 2010, 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	2011	2012	2013	2014	2015	There-after
First Mortgage Bonds	$ 1,844	$ 1,677	$ —	$ 100	$ 100	$ 63	$ 70	$ 1,344
Pollution Control Revenue Bonds	124	131	10	—	—	—	—	121
Total	$ 1,968	$ 1,808	$ 10	$ 100	$ 100	$ 63	$ 70	$ 1,465

As of December 31, 2010, 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, 2010, PGE's credit risk exposure is $1 million for commodity activities with externally-rated investment grade counterparties and matures in 2011. 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.

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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, 2010 and 2009, and the related consolidated statements of income, equity, comprehensive income, and cash flows for each of the three years in the period ended December 31, 2010. We also have audited the Company's internal control over financial reporting as of December 31, 2010, 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 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, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, 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, 2010, 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 24, 2011

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

(Dollars in millions, except per share amounts)

	Years Ended December 31, 2010	2009	2008
Revenues, net	$ 1,783	$ 1,804	$ 1,745
Operating expenses:			
Purchased power and fuel	829	944	878
Production and distribution	174	178	169
Administrative and other	186	179	190
Depreciation and amortization	238	211	208
Taxes other than income taxes	89	84	83
Total operating expenses	1,516	1,596	1,528
Income from operations	267	208	217
Other income (expense):			
Allowance for equity funds used during construction	13	18	9
Miscellaneous income (expense), net	4	3	(14)
Other income (expense), net	17	21	(5)
Interest expense	110	104	90
Income before income taxes	174	125	122
Income taxes	53	36	35
Net income	121	89	87
Less: net loss attributable to noncontrolling interests	(4)	(6)	—
Net income attributable to Portland General Electric Company	$ 125	$ 95	$ 87
Weighted-average shares outstanding (in thousands):			
Basic	75,275	72,790	62,544
Diluted	75,291	72,852	62,581
Earnings per share:			
Basic	$ 1.66	$ 1.31	$ 1.39
Diluted	$ 1.66	$ 1.31	$ 1.39
Dividends declared per common share	$ 1.035	$ 1.010	$ 0.970

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(In millions)

	As of December 31,	
	2010	**2009**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 4	$ 31
Accounts receivable, net	137	159
Unbilled revenues	93	95
Inventories, at average cost:		
Materials and supplies	34	34
Fuel	22	24
Margin deposits	83	56
Regulatory assets—current	221	197
Other current assets	67	94
Total current assets	661	690
Electric utility plant:		
Production	2,745	2,269
Transmission	372	364
Distribution	2,582	2,472
General	294	277
Intangible	286	214
Construction work in progress	125	406
Total electric utility plant	6,404	6,002
Accumulated depreciation and amortization	(2,271)	(2,144)
Electric utility plant, net	4,133	3,858
Regulatory assets—noncurrent	544	465
Nuclear decommissioning trust	34	50
Non-qualified benefit plan trust	44	47
Other noncurrent assets	75	62
Total assets	$ 5,491	$ 5,172

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,	
	2010	**2009**
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 169	$ 187
Liabilities from price risk management activities—current	188	128
Short-term debt	19	—
Current portion of long-term debt	10	186
Regulatory liabilities—current	25	27
Other current liabilities	78	92
Total current liabilities	489	620
Long-term debt, net of current portion	1,798	1,558
Regulatory liabilities—noncurrent	657	654
Deferred income taxes	445	356
Unfunded status of pension and postretirement plans	140	143
Liabilities from price risk management activities—noncurrent	188	127
Non-qualified benefit plan liabilities	97	96
Other noncurrent liabilities	78	75
Total liabilities	3,892	3,629
Commitments and contingencies (see notes)		
Equity:		
Portland General Electric Company shareholders' equity:		
Preferred stock, no par value, 30,000,000 shares authorized; none issued and outstanding as of December 31, 2010 and 2009	—	—
Common stock, no par value, 160,000,000 shares authorized; 75,316,419 and 75,210,580 shares issued and outstanding as of December 31, 2010 and 2009, respectively	831	829
Accumulated other comprehensive loss	(5)	(6)
Retained earnings	766	719
Total Portland General Electric Company shareholders' equity	1,592	1,542
Noncontrolling interests' equity	7	1
Total equity	1,599	1,543
Total liabilities and equity	$ 5,491	$ 5,172

See accompanying notes to consolidated financial statements.

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PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF EQUITY

(Dollars in millions)

	Portland General Electric Company Shareholders' Equity				Noncontrolling Interests' Equity
	Common Stock		Accumulated Other Comprehensive Loss	Retained Earnings	
	Shares	Amount			
Balance as of December 31, 2007	62,529,787	$ 646	$ (4)	$ 674	$ —
Vesting of restricted stock units	19,884	—	—	—	—
Shares issued pursuant to employee stock purchase plan	25,586	1	—	—	—
Former parent capital contributions	—	8	—	—	—
Stock-based compensation	—	4	—	—	—
Dividends declared	—	—	—	(61)	—
Net income	—	—	—	87	—
Other comprehensive income	—	—	(1)	—	—
Balance as of December 31, 2008	62,575,257	659	(5)	700	—
Issuance of common stock, net of issuance costs of $6	12,477,500	170	—	—	—
Vesting of restricted and performance stock units	128,175	—	—	—	—
Shares issued pursuant to employee stock purchase plan	29,648	—	—	—	—
Noncontrolling interests' capital contributions	—	—	—	—	7
Dividends declared	—	—	—	(76)	—
Net income (loss)	—	—	—	95	(6)
Other comprehensive loss	—	—	(1)	—	—
Balance as of December 31, 2009	75,210,580	829	(6)	719	1
Vesting of restricted and performance stock units	77,281	—	—	—	—
Shares issued pursuant to employee stock purchase plan	28,558	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

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(In millions)

	Years Ended December 31,		
	2010	**2009**	**2008**
Net income	$ 121	$ 89	$ 87
Other comprehensive income (loss) items, net of taxes:			
Pension and other postretirement plans' funded position, net of taxes of $8 in 2010, $(14) in 2009 and $69 in 2008	(9)	21	(108)
Reclassification of defined benefit pension plan and other benefits to regulatory (asset) liability, net of taxes of $(7) in 2010, $14 in 2009 and $(69) in 2008	10	(22)	107
Gains (losses) on cash flow hedges:			
Reclassification to net income for contract settlements, net of taxes of $(1) in 2008	—	—	2
Reclassification of net realized and unrealized gains to regulatory liabilities, net of taxes of $1 in 2008	—	—	(2)
Total gains on cash flow hedges	—	—	—
Total other comprehensive income (loss) items, net of taxes	1	(1)	(1)
Comprehensive income	122	88	86
Less: comprehensive loss attributable to the noncontrolling interests	(4)	(6)	—
Comprehensive income attributable to Portland General Electric Company	$ 126	$ 94	$ 86

See accompanying notes to consolidated financial statements.

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PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)

	Years Ended December 31,		
	2010	**2009**	**2008**
Cash flows from operating activities:			
Net income	$ 121	$ 89	$ 87
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	238	211	208
Increase (decrease) in net liabilities from price risk management activities	118	(145)	350
Regulatory deferrals—price risk management activities	(118)	145	(350)
Deferred income taxes	67	82	22
Regulatory deferral of settled derivative instruments	26	(31)	15
Allowance for equity funds used during construction	(13)	(18)	(9)
Senate Bill 408 deferrals, net of amortization	(13)	—	(1)
Decoupling mechanism deferrals, net of amortization	(10)	7	—
Unrealized (gains) losses on non-qualified benefit plan trust assets	(5)	(8)	17
Power cost deferrals, net of amortization	(1)	(18)	2
Trojan refund liability	—	—	34
Other non-cash income and expenses, net	15	32	(15)
Changes in working capital:			
Decrease in receivables	24	11	6
(Increase) decrease in margin deposits	(27)	133	(163)
Income tax refund received	53	—	—
Increase in income taxes receivable	(22)	(53)	—
Decrease in payables	(11)	(16)	(11)
Other working capital items, net	—	2	(8)
Contribution to pension plan	(30)	—	—
Distribution of Trojan refund liability	—	(34)	—
Other, net	(21)	(3)	(1)
Net cash provided by operating activities	391	386	183
Cash flows from investing activities:			
Capital expenditures	(450)	(696)	(383)
Sales of nuclear decommissioning trust securities	50	36	23
Purchases of nuclear decommissioning trust securities	(46)	(36)	(19)
Distribution from nuclear decommissioning trust	19	—	—
Insurance proceeds	—	—	3
Other, net	(3)	(4)	(6)
Net cash used in investing activities	(430)	(700)	(382)

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,		
	2010	**2009**	**2008**
Cash flows from financing activities:			
Proceeds from issuance of long-term debt	$ 249	$ 580	$ 50
Payments on long-term debt	(186)	(142)	(56)
Proceeds from issuance of common stock, net of issuance costs	—	170	—
Issuances (maturities) of commercial paper, net	19	(65)	65
Borrowings on short-term debt	11	—	7
Payments on short-term debt	(11)	(7)	—
Borrowings on revolving lines of credit	—	82	189
Payments on revolving lines of credit	—	(213)	(58)
Dividends paid	(78)	(72)	(60)
Debt issuance costs	(2)	(5)	(1)
Noncontrolling interests’ capital contribution	10	7	—
Net cash provided by financing activities	12	335	136
Change in cash and cash equivalents	(27)	21	(63)
Cash and cash equivalents, beginning of year	31	10	73
Cash and cash equivalents, end of year	$ 4	$ 31	$ 10
Supplemental disclosures of cash flow information:			
Cash paid for interest, net of amounts capitalized	$ 98	$ 74	$ 73
Cash paid for income taxes	—	2	20
Non-cash investing and financing activities:			
Accrued capital additions	12	17	16
Accrued dividends payable	20	20	16
Former parent’s capital contribution of Oregon tax credits	—	—	8

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
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, 2010, PGE served 820,676 retail customers with a service area population of approximately 1.7 million, comprising approximately 44% of the state's population.

As of December 31, 2010, PGE had 2,671 employees, with 872 employees covered under two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 837 and 35 employees and expire on February 28, 2012 and August 1, 2011, 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, issuance 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. 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 the 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 requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosures of potential gain contingencies or contingent liabilities, as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Reclassifications

Certain reclassifications have been made to the 2009 and 2008 consolidated statements of cash flows to conform with the 2010 presentation. Such reclassification included the segregation of the Regulatory deferral of settled derivative instruments and Decoupling mechanism deferrals, net from Other non-cash income and expenses, net and the increase in Income taxes receivable from Other working capital items, net in operating activities, as well as the segregation of Issuances (maturities) of commercial paper, net from Borrowings (payments) on short-term debt in financing activities. In addition, certain reclassifications have been made to the 2009 deferred income tax assets and deferred income tax liabilities presented in Note 11, Income Taxes, to conform with the 2010 presentation.

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. Cash equivalents consist of money market funds, of which PGE had none as of December 31, 2010 and $18 million as of December 31, 2009.

Accounts Receivable

Accounts receivable are recorded at invoiced amounts and do not bear interest when recorded. A late fee may be assessed on residential account balances after 60 days and on nonresidential balances after 30 days. An account balance is charged-off after efforts have been made to collect such amount, but no sooner than 45 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 and natural gas, and futures contracts for natural gas. 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 unless hedge accounting applies, 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 minimize net power costs for retail customers.

The OPUC recognizes derivative contracts only at the time of settlement. Contracts that qualify for the normal purchases and normal sales exception are not required to be recorded at fair value. Unrealized gains and losses from contracts that qualify as cash flow hedges are recorded net in Other comprehensive income and contracts not designated as cash flow hedges are recorded net in Purchased power and fuel expense on the statements of income. The timing difference between the recognition of unrealized gains and losses on derivative instruments and their realization and subsequent recovery in rates is recorded as a regulatory asset or regulatory liability to reflect the effects of regulatory accounting.

Electricity sales and purchases that are physically settled are recorded in Revenues and Purchased power and fuel expense upon settlement, respectively. Electricity sales and purchases resulting from derivative activities that are not physically settled are recorded on a net basis in Purchased power and fuel expense.

Pursuant to transactions entered into in connection with PGE's price risk management activities, the Company may be required to provide deposits with certain counterparties. These deposits are based on the contract terms and commodity prices and can vary period to period. These deposits are classified as Margin deposits in the accompanying consolidated balance sheets and were $83 million and $56 million as of December 31, 2010 and 2009, respectively.

Inventories

PGE's inventories, 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. Natural gas inventory is valued at the lower of average cost or market. Oil and coal inventories are valued at average cost as they are recovered at average cost when utilized.

Property, Plant and Equipment

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 allowance for funds used during construction (AFDC). Plant replacements are capitalized, with minor items charged to expense as incurred. 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.

Costs which are disallowed for recovery in rates are charged to expense at the time such disallowance is probable. Pursuant to an OPUC order received in January 2010, PGE was ordered to forego the recovery of certain capital costs incurred in connection with a delay in the completion of the Selective Water Withdrawal project, and pursue recovery of these costs through insurance and from firms involved in the design, construction and installation of the project. Accordingly, during the fourth quarter of 2009, PGE charged to expense approximately $6 million related to the Selective Water Withdrawal project. Such amount is included in Production and distribution expense in the consolidated statement of income for the year ended December 31, 2009.

PGE records AFDC, which represents the pre-tax cost of borrowed funds used for construction purposes and the rate granted in the latest rate proceeding for equity funds. AFDC is capitalized as part of the cost of plant and credited to the statement of income. The average rate used by PGE was 8% in 2010, 7% in 2009, and 8% in 2008. AFDC from borrowed funds was $9 million in 2010, $12 million in 2009, and $6 million in 2008 and is reflected in the consolidated statements of income as a reduction to interest expense. AFDC from equity funds was $13 million in 2010, $18 million in 2009, and $9 million in 2008 and is reflected as a component of Other income (expense), net.

Costs of periodic major maintenance inspections and overhauls at the Company's generating plants are charged to operating expense as incurred.

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 approximately 3.9% in 2010, 3.8% in 2009, and 3.7% in 2008. Estimated asset retirement removal costs included in depreciation expense approximated $47 million in each of the years ended December 31, 2010 and 2009, and $43 million in the year ended December 31, 2008.

Periodic studies are conducted to update depreciation parameters (i.e. retirement dispersion patterns, average service lives, and net salvage rates), including estimates of asset retirement obligations (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. On September 13, 2010, PGE received an order from the OPUC authorizing new depreciation rates to be effective January 2011. The average lives below reflect depreciation lives effective in 2010.

Thermal production plants are depreciated using a life-span methodology which ensures that plant investment is recovered by the forecasted retirement date, which range from 2020 to 2042. Depreciation is provided on the Company's other classes of plant in service over their estimated average service lives, which are as follows:

Production, excluding thermal:	
Hydro	89 years
Wind	27 years
Transmission	48 years
Distribution	39 years
General	13 years

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 charged to AROs for assets that meet the definition of a legal obligation and to accumulated asset retirement removal costs, included in Regulatory liabilities, for assets without AROs.

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 $133 million and $122 million as of December 31, 2010 and 2009, respectively, with amortization expense of $17 million in 2010, $16 million in 2009, and $14 million in 2008. Future estimated amortization expense as of December 31, 2010 is as follows: $17 million in 2011, $14 million in 2012, $8 million in 2013, $5 million in 2014 and $4 million in 2015.

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 (expense), 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 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 (1) increased competition that restricts the Company's ability to establish prices to recover specific costs, and (2) 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 that are expected to impact future cost recovery, management believes that the Company's regulatory assets are probable of future recovery.

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 prices to reflect a portion of the difference between each year's forecasted NVPC included in prices (baseline) and actual NVPC. PGE is subject to a portion of the business risk or benefit associated with the difference between actual NVPC and that included in base prices by application of a fixed asymmetrical deadband within which PGE absorbs cost increases or decreases, with a 90/10 sharing of costs and benefits between customers and the Company, respectively, outside of the deadband. Any customer refund or collection is also subject to a regulated earnings test. A refund will occur only to the extent that it results in PGE's actual regulated return on equity (ROE) for that year being no less than 1% above the Company's latest authorized ROE. 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 last authorized ROE. PGE's authorized ROE was 10.0% for both 2010 and 2009. A final determination of any customer refund or collection is made by the OPUC through an annual 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 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 deadband, a regulatory asset is recorded for any future amount due from retail customers.

For 2010, the deadband ranged from $17 million below to $35 million above the baseline. Although PGE's actual NVPC as determined pursuant to the PCAM for 2010 was below the baseline by $12 million, it was within the established deadband and, accordingly, no customer refund was recorded in 2010. A final determination regarding the 2010 PCAM results will be made by the OPUC through a public filing and review in 2011.

For 2009, the deadband ranged from $15 million below to $29 million above the baseline. Although PGE's actual NVPC as determined pursuant to the PCAM for 2009 exceeded the baseline by $22 million, it was within the established deadband and, accordingly, no customer collection was recorded in 2009. A final determination regarding the 2009 PCAM results was made by the OPUC through a public filing and review in 2010, which concluded that no customer collection was warranted for 2009.

Asset Retirement Obligations

The fair value of a liability for 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. Because of the long lead time involved until future decommissioning activities occur, the Company uses present value techniques as 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. A material loss contingency is accrued and disclosed 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 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. Legal costs incurred in connection with loss contingencies are expensed as incurred.

If a probable loss cannot be reasonably estimated, no accrual is recorded, but the loss contingency is disclosed and the disclosure includes a statement to that effect. A material loss contingency will also be disclosed when it is reasonably possible that an asset has been impaired or a liability incurred.

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) is comprised of the difference between the pension and other postretirement plans' obligations recognized in net income to date, and the unfunded position as of December 31, 2010 and 2009.

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 $39 million in 2010, $38 million in 2009, and $36 million in 2008.

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 $95 million and $91 million as of December 31, 2010 and 2009, respectively, and will be included in prices when the temporary differences reverse.

Investment tax credits utilized were deferred and amortized to income over the lives of the related properties, and will be fully amortized by the end of 2011.

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 (expense), net, respectively, in the consolidated statements of income.

Recent Accounting Pronouncements

On January 1, 2010, PGE adopted certain provisions of Accounting Standards Codification 810, *Consolidation* (ASC 810), which changed how a company determines when a variable interest entity (VIE) should be consolidated. The determination of whether a company is required to consolidate an entity is based on, among other things, an entity's purpose and design and a company's ability to direct the activities of the entity that most significantly impact the entity's economic performance. ASC 810 requires a company to provide additional disclosures about its involvement with VIEs and what any significant change in risk exposure does to that involvement. A company is also required to disclose how its involvement with a VIE affects the company's performance. The adoption of these provisions of ASC 810 did not have a material impact on PGE's consolidated financial position, consolidated results of operations, or consolidated cash flows.

Accounting Standards Update (ASU) 2010-06, *Fair Value Measurements and Disclosures (Topic 820) - Improving Disclosures about Fair Value Measurement* (ASU 2010-06) requires (i) new disclosures about the transfers in and out of fair value measurement Levels 1 and 2 and a description of the reasons for the transfers and (ii) separate reporting about purchases, sales, issuances, and settlements for Level 3 fair value measurements. For additional information on the three broad levels, see Note 4, Fair Value of Financial Instruments. ASU 2010-06 also clarifies existing disclosures and requires (i) an entity to provide fair value measurement disclosures for each class of assets and liabilities and (ii) disclosures about inputs and valuation techniques. In accordance with the provisions of ASU 2010-06, on January 1, 2010, PGE adopted the requirements of ASU 2010-06, except for the disclosures about purchases, sales, issuances and settlements in the roll forward of activity of Level 3 fair value measurements, which did not have a material impact on PGE's consolidated financial position, consolidated results of operations, or consolidated cash flows. Based on the provisions of ASU 2010-06, PGE will adopt the disclosures requirements about purchases, sales, issuances and settlements in the roll forward of activity in Level 3 fair value measurements on January 1, 2011, which is not expected to have a material impact on PGE'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 as of December 31, 2010 and 2009. The following is the activity in the allowance for uncollectible accounts (in millions):

	Years Ended December 31,		
	2010	**2009**	**2008**
Balance as of beginning of year	$ 5	$ 4	$ 5
Increase in provision	7	9	8
Amounts written off, less recoveries	(7)	(8)	(9)
Balance as of end of year	$ 5	$ 5	$ 4

Trust Accounts

PGE maintains two trust accounts: (1) the non-qualified benefit plan trust, which represents amounts set aside by the Company to fund its obligation under the non-qualified benefit plans, primarily the Supplemental Executive Retirement Plan (SERP), management deferred compensation plans (MDCPs) and other non-qualified plans for certain current and former employees and directors, and (2) the nuclear decommissioning trust, which is restricted to reimbursing PGE for Trojan decommissioning expenditures and represents amounts collected from customers less qualified expenditures plus any realized and unrealized gains and losses on the investments held therein.

The trusts hold investments in cash, cash equivalents, marketable securities, and insurance contracts. The insurance contracts are recorded at cash surrender value, with any changes recorded in earnings. The trusts are comprised of the following investments as of December 31 (in millions):

	Nuclear Decommissioning Trust		Non-Qualified Benefit Plan Trust	
	2010	2009	2010	2009
Cash equivalents	$ 13	$ 31	$ —	$ —
Marketable securities, at fair value:				
Equity securities	—	—	19	21
Debt securities	21	19	2	4
Insurance contracts, at cash surrender value	—	—	23	22
Total	$ 34	$ 50	$ 44	$ 47

Other Current Assets and Other Current Liabilities

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

	As of December 31,	
	2010	2009
Other current assets:		
Income taxes receivable	$ 22	$ 56
Other	45	38
Total other current assets	$ 67	$ 94
Other current liabilities:		
Accrued interest payable	$ 26	$ 27
Other	52	65
Total other current liabilities	$ 78	$ 92

Other 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 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, 2010 and 2009, PGE has recorded preliminary engineering costs of $13 million and $5 million, respectively. For the years ended December 31, 2010, 2009, and 2008, PGE did not expense any material preliminary engineering costs.

NOTE 4: FAIR VALUE OF FINANCIAL INSTRUMENTS

The fair value of financial instruments, both assets and liabilities recognized and not recognized in PGE's consolidated balance sheet, for which it is practicable to estimate fair value is as follows as of December 31, 2010 and 2009:

- Derivative instruments are recorded at fair value and are based on published market indices as adjusted for other market factors such as location pricing differences or internally developed models;
- Certain trust assets, consisting of money market funds and fixed income securities included in the Nuclear decommissioning trust and marketable securities included in the Non-qualified benefit plan trust, are recorded at fair value and are based on quoted market prices; and
- The fair value of long-term debt is estimated based on the quoted market prices for the same or similar issues or on the current rates offered to PGE for debt of similar remaining maturities. As of December 31, 2010, the estimated aggregate fair value of PGE's long-term debt was $1,968 million, compared to its $1,808 million carrying amount. As of December 31, 2009, the estimated aggregate fair value of PGE's long-term debt was $1,818 million, compared to its $1,744 million carrying amount.

A 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. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives, listed equities and U.S. government treasury securities.

Level 2—Pricing inputs are other than quoted market prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange-traded derivatives such as over-the-counter forwards and swaps.

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

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(continued)

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

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

	As of December 31, 2009			
	Level 1	Level 2	Level 3	Total
Assets:				
Nuclear decommissioning trust [(1)]:				
Money market funds	$ —	$ 31	$ —	$ 31
Debt securities:				
U.S. treasury securities	4	—	—	4
Corporate debt securities	—	8	—	8
Mortgage-backed securities	—	5	—	5
Municipal securities	—	2	—	2
Non-qualified benefit plan trust [(2)]:				
Equity securities:				
Mutual funds	19	—	—	19
Common stocks	2	—	—	2
Debt securities - mutual funds	4	—	—	4
Assets from price risk management activities [(1)] [(3)]:				
Electricity	—	7	—	7
Natural gas	—	6	—	6
	$ 29	$ 59	$ —	$ 88
Liabilities - Liabilities from price risk management activities [(1)] [(3)]:				
Electricity	$ —	$ 72	$ 9	$ 81
Natural gas	—	29	145	174
	$ —	$ 101	$ 154	$ 255

(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 which are recorded at cash surrender value.
(3) For further information, see Note 5, Price Risk Management.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company’s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. During the year ended December 31, 2010, PGE determined that the money market funds held by the Nuclear decommissioning trust should be classified as Level 2 rather than Level 1, as such investments do not have an active market for the identical assets. Accordingly, the Company corrected the classification of money market funds from Level 1 to Level 2 in the above table as of December 31, 2009.

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

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

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

	Years Ended December 31,		
	2010	2009	2008
Assets (liabilities) from price risk management activities, net as of beginning of year	$ (154)	$ (123)	$ 1
Net realized and unrealized losses	(65)	(47)	(166)
Purchases, issuances, and settlements, net	(27)	—	(12)
Net transfers out of Level 3	126	16	54
Liabilities from price risk management activities, net as of end of year	$ (120)	$ (154)	$ (123)
Level 3 net realized and unrealized losses that have been fully offset by the effect of regulatory accounting	$ (95)	$ (49)	$ (120)

Transfers into Level 3 occur when significant inputs used to value the Company's derivative instruments become less observable, such as a delivery location becoming significantly less liquid. Transfers out of Level 3 occur when the significant inputs become more observable, such as the time between the valuation date and the delivery term of a transaction becomes shorter. PGE records transfers in and transfers out of Level 3 at the end of the reporting period for all of its financial instruments.

NOTE 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, which may include forward, swap, and option contracts for electricity, natural gas, oil, and foreign currency, and futures contracts for natural gas and oil, in its retail electric utility activities to manage its exposure to commodity price risk and foreign exchange rate risk, mitigate the effects of market fluctuations, and minimize net power costs for service to its retail customers. These derivative instruments are recorded at fair value on the statement of financial position, 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 realized. This accounting treatment defers the mark-to-market gains and losses on derivative activities until settlement, reducing volatility related to commodity price risk and foreign currency exchange rate risk. 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 not to net on the balance sheet the positive and negative exposures resulting from derivative instruments entered into with counterparties where a master netting arrangement exists. As of December 31, 2010 and 2009, the Company had $31 million and $28 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 2014, were as follows (in millions):

	As of December 31,					
	2010			2009		
Commodity:						
Electricity		9	MWh		12	MWh
Natural gas		93	Decatherms		96	Decatherms
Foreign currency exchange	$	7	Canadian	$	5	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, 2010	As of December 31, 2009
Current assets:		
Commodity contracts:		
Electricity	$ 4	$ 6
Natural gas	9	5
Total current derivative assets	13 (1)	11 (1)
Noncurrent assets:		
Commodity contracts:		
Electricity	1	1
Natural gas	2	1
Total noncurrent derivative assets	3 (2)	2 (2)
Total derivative assets not designated as hedging instruments	$ 16	$ 13
Total derivative assets	$ 16	$ 13
Current liabilities:		
Commodity contracts:		
Electricity	$ 77	$ 57
Natural gas	111	71
Total current derivative liabilities	188	128
Noncurrent liabilities:		
Commodity contracts:		
Electricity	42	24
Natural gas	146	103
Total noncurrent derivative liabilities	188	127
Total derivative liabilities not designated as hedging instruments	$ 376	$ 255
Total derivative liabilities	$ 376	$ 255

(1) Included in Other current assets on the consolidated balance sheet.
(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,	
	2010	2009
Commodity contracts:		
Electricity	$ 127	$ 79
Natural Gas	192	101

Unrealized gains and losses and certain realized gains and 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, 2010 and 2009, $258 million and $98 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, 2010 related to PGE's derivative activities would be realized as a result of the settlement of the underlying derivative instrument (in millions):

	2011	2012	2013	2014	Total
Commodity contracts:					
Electricity	$ 73	$ 25	$ 11	$ 5	$ 114
Natural gas	102	92	43	9	246
Net unrealized loss	$ 175	$ 117	$ 54	$ 14	$ 360

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, 2010 was $314 million, for which the Company had $180 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, 2010, the cash requirement to either post as collateral or settle the instruments immediately would have been $302 million.

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

	As of December 31,	
	2010	2009
Assets from price risk management activities:		
Counterparty A	23%	41%
Counterparty B	22	14
Counterparty C	1	15
Counterparty F	11	2
Counterparty E	10	2
	67%	74%
Liabilities from price risk management activities:		
Counterparty A	24%	19%
Counterparty C	12	13
Counterparty D	9	14
	45%	46%

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	As of December 31, 2010 Current	2010 Noncurrent	2009 Current	2009 Noncurrent
Regulatory assets:					
Price risk management [1]	2 years	$ 175	$ 185	$ 118	$ 125
Pension and other postretirement plans [1]	[2]	—	213	—	196
Deferred income taxes [1]	[3]	—	95	—	91
Deferred broker settlements [1]	1 year	24	—	49	1
Renewable energy deferral	1 year	22	—	6	4
Boardman power cost deferral		—	—	17	—
Debt reacquisition costs [1]	10 years	—	23	—	26
Regulatory treatment of income taxes (SB 408)	[4]	—	1	7	—
Other [5]	Various	—	27	—	22
Total regulatory assets		$ 221	$ 544	$ 197	$ 465
Regulatory liabilities:					
Asset retirement removal costs [6]	[3]	$ —	$ 588	$ —	$ 541
Regulatory treatment of income taxes (SB 408)	1 year	5	9	9	24
Asset retirement obligations [6]	[3]	—	33	—	30
Trojan ISFSI pollution control tax credits	[7]	18	4	—	17
Other	Various	2	23	18	42
Total regulatory liabilities		$ 25	$ 657	$ 27	$ 654

(1) Does not include a return on investment.
(2) Recovery expected over the average service life of employees. For additional information, see Note 2, Summary of Significant Accounting Policies.
(3) Recovery expected over the estimated lives of the assets.
(4) Collection period not yet determined.
(5) Of the total other unamortized regulatory asset balances, a return is recorded on $25 million and $22 million as of December 31, 2010 and 2009, respectively.
(6) Included in rate base for ratemaking purposes.
(7) The refund period for the $4 million noncurrent portion of the Trojan ISFSI pollution control tax credits has not yet been determined.

As of December 31, 2010, PGE had regulatory assets of $48 million earning a return on investment at the following rates: (1) $23 million at PGE's authorized cost of capital, 8.284% through 2010; (2) $14 million at the approved rate for deferred accounts under amortization, ranging from 2.05% to 4.27%, depending on the year of approval; and (3) $11 million earning a return by inclusion in rate base.

Price risk management represents the difference between the recognition of unrealized gains and losses on derivative instruments related to price risk management activities and their realization and subsequent recovery in rates. For further information, see Note 5, Price Risk Management.

Pension and other postretirement plans represents unrecognized components of the benefit plans' funded status, which are recoverable in rates 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 rates 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 rate recovery in the corresponding contract settlement month.

Renewable energy deferral reflects the accrued net revenue requirement related to new renewable resources and associated transmission that are not yet included in customer prices, with the majority related to the placing in service of the Biglow Canyon Wind Farm. Recovery of net revenue requirements associated with new renewable resources, which are required by the 2007 Oregon Renewable Energy Act, is allowed under a renewable adjustment clause mechanism authorized by the OPUC.

Boardman power cost deferral represents that portion of excess replacement power costs, plus accrued interest, associated with the forced outage of Boardman from November 18, 2005 through February 5, 2006, which was deferred for later ratemaking treatment. On February 12, 2010, the OPUC issued an order reducing the amount to be recovered from customers by $18 million; such reduction was charged to Purchased power and fuel expense in the fourth quarter of 2009. Pursuant to the order, collection of the remaining deferred balance was offset in the first quarter of 2010 with certain credits then owed to customers related to accrued savings on decommissioning activities at PGE's closed Trojan Nuclear Plant.

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

Regulatory treatment of income taxes regulatory asset or regulatory liability is established pursuant to Oregon Senate Bill 408 (SB 408), which was enacted in 2005. SB 408 requires regulated investor-owned utilities that provide electric or natural gas service to more closely match estimates of income taxes collected in revenues with the amount of income taxes paid to governmental entities by the investor-owned utilities or their consolidated group. The law requires a report to be filed annually with the OPUC regarding the amount of taxes paid by the utility and the amount of taxes authorized to be collected in rates. If the difference between these two amounts is greater than $100,000, the utility is required to adjust prices prospectively. In any given reporting year, a regulatory liability is established for future refunds to customers while a regulatory asset is established for future collections from customers, with interest accrued thereon as approved by the OPUC.

During the fourth quarter of 2010, the OPUC staff (Staff) reviewed the 2009 SB 408 reports of PGE and other northwest utilities, with the following two outcomes:

- PGE reached a stipulation with Staff and the Citizens' Utility Board (CUB) on the Company's 2009 SB 408 report, which reduced its original estimated refund to customers of $13 million recorded in 2009 to $8 million. The difference of $5 million was included in Revenues, net in the consolidated statement of income for the year ended December 31, 2010. The Industrial Customers of Northwest Utilities (ICNU) has filed objections to the stipulation, claiming customer refunds totaling $61 million are required. In February 2011, PGE filed rebuttal testimony to ICNU's objections, stating ICNU's claim is without merit, asking that the objections be denied, and requesting that the stipulation be approved. A ruling from the OPUC on PGE's 2009 SB 408 report is expected by April 2011.

- Based on the review of the other northwest utilities' 2009 SB 408 reports, Staff determined that the current application of the normalization floor by some of the other utilities in certain calculations was not in accordance with the intent of SB 408. The "normalization floor" was created in the SB 408 rules in 2007 to preserve the federal tax statutory requirement to normalize the benefit of accelerated tax depreciation. In February 2011, the OPUC issued temporary rules that will significantly limit the scope and impact of the normalization floor. Such rules are not expected to have an impact on PGE's 2009 SB 408 report, as the Company was not subject to the normalization floor in 2009.

The temporary rules, which are effective for 180 days, would have an impact on the Company's SB 408 calculation for 2010 if they are adopted permanently. Through September 30, 2010, PGE had recorded a $24 million estimated future collection from customers related to SB 408 for 2010, based on existing rules, which included the application of the normalization floor rule. During the fourth quarter of 2010, PGE reversed this $24 million collection from customers based on the uncertainty of the outcome of the regulatory process and applicable rules. Accordingly, PGE has not recorded any collection from or refund to customers related to SB 408 for 2010 as of December 31, 2010. PGE estimates the collection from customers related to SB 408 for 2010 ranges from less than $1 million, based on the temporary rules, to $33 million, based on existing rules. The 2010 SB 408 report will be filed with the OPUC no later than October 15, 2011, with the OPUC's decision on such report expected no later than April 2012.

NOTE 7: ASSET RETIREMENT OBLIGATIONS

AROs, which are included in Other noncurrent liabilities in the consolidated balance sheet, consist of the following (in millions):

	As of December 31,	
	2010	**2009**
Trojan decommissioning activities	$ 38	$ 39
Utility plant	16	14
Non-utility property	10	10
Asset retirement obligations	$ 64	$ 63

Trojan decommissioning activities represents the present value of future decommissioning expenditures for the plant which ceased operation in 1993. The remaining decommissioning activities consist of the long-term operation and decommissioning of the ISFSI, an NRC-licensed interim dry storage facility that houses the spent nuclear fuel at the plant site until permanent off-site storage is available. Decommissioning of the ISFSI and final site restoration activities will begin once all of the spent fuel is shipped to a U.S. Department of Energy (USDOE) facility, which is not expected prior to 2033.

In 2004, the co-owners of Trojan (PGE, Eugene Water & Electric Board, and PacifiCorp) 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 are seeking approximately $128 million in damages. PGE's share of any recovery would be approximately 67%. A trial before the U.S. Court of Federal Claims is scheduled to commence in the fourth quarter of 2011. The Trojan asset retirement obligation will not be impacted by the outcome of this case as such potential recovery is for past decommissioning costs and an asset retirement obligation reflects only future decommissioning expenditures. Any proceeds received related to this legal matter would be returned to customers to offset amounts previously collected related to Trojan decommissioning activities.

Utility plant represents AROs which 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 has been substantially completed at Bull Run, with the exception of the possible demolition of the powerhouse if an alternative use for the facility is not chosen. Environmental monitoring is scheduled to continue through 2012.

Non-utility property 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,		
	2010	**2009**	**2008**
Balance as of beginning of year	$ 63	$ 58	$ 91
Liabilities incurred	1	—	—
Liabilities settled	(3)	(4)	(13)
Accretion expense	4	4	2
Revisions in estimated cash flows	(1)	5	(22)
Balance as of end of year	$ 64	$ 63	$ 58

Pursuant to regulation, utility plant AROs are included in depreciation expense and in prices charged to customers. 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 $5 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 project 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, however, as management believes that these assets will be used in utility operations for the foreseeable future. Ongoing removable activity as equipment is replaced is charged to accumulated asset retirement removal costs, included in Regulatory liabilities.

NOTE 8: REVOLVING CREDIT FACILITIES

PGE has the following unsecured revolving credit facilities:

- A $370 million unsecured revolving credit facility with a group of banks, of which $10 million is scheduled to terminate in July 2012 and $360 million in July 2013;
- A $200 million credit facility with a group of banks, which is scheduled to terminate in December 2012; and
- A $30 million credit facility with a bank, which is scheduled to terminate in June 2013.

Pursuant to the individual terms of the agreements, all credit facilities may be used for general corporate purposes and as backup for commercial paper borrowings. The $370 million and $30 million credit facilities also permit the issuance of standby letters of credit. 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. All credit facilities require annual fees based on PGE's unsecured credit ratings, and contain customary covenants and default provisions, including a requirement that limits consolidated indebtedness, as defined in the agreement, to 65% of total capitalization. As of December 31, 2010, PGE was in compliance with this covenant with a 53.4% 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 $750 million through February 6, 2012. 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, 2010, PGE had no borrowings and $19 million in commercial paper outstanding under the credit facilities, with $209 million in letters of credit issued. As of December 31, 2010, the aggregate unused available credit under the credit facilities is $372 million.

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

	Years Ended December 31,		
	2010	2009	2008
Average daily amount of short-term debt outstanding	$ 9	$ 28	$ 33
Weighted daily average interest rate *	0.4%	1.3%	3.8%
Maximum amount outstanding during the year	$ 51	$ 205	$ 199

* 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,	
	2010	2009
First Mortgage Bonds, rates range from 3.46% to 9.31%, with a weighted average rate of 5.85% in 2010 and 6.0% in 2009, due at various dates through 2040	$ 1,678	$ 1,550
Pollution Control Revenue Bonds:		
Port of Morrow, Oregon, rates of 5% and 5.2% at December 31, 2010 and 2009, respectively, due 2033	23	23
City of Forsyth, Montana, rates of 5% and 5.2% at December 31, 2010 and 2009, respectively, due 2033	119	119
Port of St. Helens, Oregon, 4.8% to 5.25% rate, due in 2014	10	47
Total Pollution Control Revenue Bonds	152	189
7.875% unsecured notes, due March 10, 2010	—	149
Pollution Control Revenue Bonds owned by PGE	(21)	(142)
Unamortized debt discount	(1)	(2)
Total long-term debt	1,808	1,744
Less: current portion of long-term debt	(10)	(186)
Long-term debt, net of current portion	$ 1,798	$ 1,558

First Mortgage Bonds—The Indenture securing PGE’s First Mortgage Bonds constitutes a direct first mortgage lien on substantially all utility property, other than expressly excepted property. During 2010, PGE issued a total of $128 million of first mortgage bonds as follows:

- On January 15th, $70 million of 3.46% Series due January 2015, with interest payable semi-annually on January 15th and July 15th; and
- On June 15th, $58 million of 3.81% Series due June 2017, with interest payable semi-annually on June 15th and December 15th.

Pollution Control Revenue Bonds—On May 1, 2009, PGE repurchased $142 million of Pollution Control Revenue Bonds (Bonds), consisting of $23 million issued through the Port of Morrow, Oregon, and $119 million issued through the City of Forsyth, Montana. On March 11, 2010, PGE remarketed $121 million of the Bonds due May 2033 at 5.0%, with interest payable semi-annually on March 1st and September 1st, which are backed by first mortgage bonds. PGE has the option to remarket, through 2033, the $21 million of Bonds held by the Company and can choose a new interest rate period that would be daily, weekly, or a fixed term. The new interest rate would be based on market conditions at the time of remarketing and could be backed by first mortgage bonds or a bank letter of credit depending on market conditions.

In 2008, PGE repurchased $5.8 million of Pollution Control Revenue Bonds Series 1996 (Bonds) issued through the Port of Morrow, which was paid to 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 in the United States Bankruptcy Court for the Southern District of New York. PGE subsequently filed a claim for return of the Bonds from Lehman. On November 9, 2009, the trustee appointed to liquidate the assets of Lehman (Trustee) allowed PGE's claim as a net equity claim for securities. At the time, PGE believed it would receive back the entire amount of the Bonds at some point during the bankruptcy proceedings.

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

During 2010, PGE repaid $37 million of 4.8% Port of St. Helens Pollution Control Revenue Bonds. On January 13, 2011, PGE redeemed and retired the remaining $10 million of Port of St. Helens Pollution Control Revenue Bonds outstanding at December 31, 2010.

Other—In addition to the above long-term debt transactions, PGE repaid $149 million of 7.875% unsecured notes on March 15, 2010.

As of December 31, 2010, the future minimum principal payments on long-term debt are as follows (in millions):

Years ending December 31:		
2011	$	10
2012		100
2013		100
2014		63
2015		70
Thereafter		1,465
	$	1,808

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, of which substantially all participants are current or former PGE employees. The assets of the pension plan are held in a trust and are comprised of investment vehicles such as: common stocks, mutual funds, private equity funds, fixed income securities, common and collective trust funds, partnerships/joint ventures, corporate debt securities, and other investments, all of which are recorded at fair value. Pension plan calculations include several assumptions which are reviewed annually and are updated as appropriate. The measurement date for the pension plan is December 31.

PGE made a $30 million contribution to the pension plan in 2010, and no contributions in 2009 and 2008. The Company does not expect to make any contribution in 2011.

Effective January 31, 2009, the pension plan was closed to new non-bargaining employees, with no changes in benefits to current participants. For non-bargaining employees hired on or after February 1, 2009, the pension plan has been replaced with a new contribution to the defined contribution plan. For additional information, see the description of the Company's 401(k) plan included in this Note. The pension plan was closed to new bargaining employees as of January 1, 1999.

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

Contributions made to a voluntary employees' beneficiary association trust are used to fund these plans. The assets of other postretirement plans are comprised of investments in: 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. Costs of these plans, based upon an actuarial study, are included in prices charged to customers. Postretirement benefit plan calculations include several assumptions which are reviewed annually with PGE's consulting actuaries and trust investment consultants and updated as appropriate.

PGE has Health Reimbursement Accounts (HRAs) for its employees. Contributions are made to trust accounts to provide for claims by retirees for qualified medical costs. For active bargaining employees, the participants' accounts are credited with 58% of the value of the employee's accumulated sick time as of April 30, 2004, plus 100% of their earned time off accumulated at the time of retirement. Between July 1, 2007 and June 30, 2008, the Company made additional contributions to the trust of $0.25 per compensable hour for each bargaining unit participant, increasing to $0.50 per compensable hour from July 1, 2008 through March 3, 2009. The compensable hour contribution as of March 4, 2009 has been redirected to the participants' 401(k) plan. For active non-bargaining employees, the Company grants a fixed dollar amount that will become available for qualified medical expenses upon their retirement.

Minimal contributions were made to the postretirement and non-bargaining HRA plans in 2010, 2009 and 2008. Contributions approximating $1 million were made to the bargaining unit HRA in 2010, 2009 and 2008. No contributions are currently expected to be made to the other postretirement plans in 2011. The measurement date for the postretirement plans is December 31.

Non-Qualified Benefit Plans—The Non-Qualified Benefit Plans (NQBP) in the following tables include obligations for a SERP, which was closed to new participants in 1997, pension benefits for employees that participate in the unfunded MDCP and pension benefits for directors. 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 certain 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 the primary source for funding these plans.

The following table provides information on the trust assets and plan liabilities associated with the NQBP included in PGE's consolidated balance sheets as of December 31, 2010 and 2009 (in millions):

	2010			2009		
	NQBP	Other NQBP	Total	NQBP	Other NQBP	Total
Non-qualified benefit plan trust	$ 19	$ 25	$ 44	$ 20	$ 27	$ 47
Non-qualified benefit plan liabilities *	24	73	97	25	71	96

* For the NQBP, excludes the current portion of $2 million in 2010 and 2009, which is classified in Other current liabilities in the consolidated balance sheets.

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 of risk. 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,		
	2010	2009	Target *
Defined Benefit Pension Plan:			
Equity securities	68%	67%	67%
Debt securities	32	33	33
	100%	100%	100%
Other Postretirement Benefit Plans:			
Equity securities	46%	50%	47%
Debt securities	54	50	53
	100%	100%	100%
Non-Qualified Benefits Plans:			
Debt securities	5%	8%	7%
Equity securities	42	46	42
Insurance contracts	53	46	51
	100%	100%	100%

* The Target for the Defined Benefit Plan represents the mid-point of the investment target range approved by the Investment Committee. 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, 2010			
	Level 1	Level 2	Level 3	Total
Defined Benefit Pension Plan assets:				
Equity securities:				
U.S. small cap core	$ 12	$ —	$ —	$ 12
U.S. small cap value	12	—	—	12
U.S. micro cap	14	—	—	14
U.S. large cap growth	—	27	—	27
U.S. large cap value	—	28	—	28
Large cap long/short	—	56	—	56
International large cap growth	—	56	—	56
Fixed income securities:				
U.S. core plus	—	70	—	70
U.S. long government/credit	—	12	—	12
Short duration	—	—	—	—
Mutual funds (1)	135	—	—	135
Private equity funds (2)	—	—	23	23
U.S. large cap futures and U.S. hedge funds (3)	—	—	28	28
	$ 173	$ 249	$ 51	$ 473
Other Postretirement Benefit Plans assets:				
Equity securities:				
U.S. small cap core	$ 1	$ —	$ —	$ 1
U.S. large cap growth	—	1	—	1
U.S. large cap value	—	1	—	1
International large cap growth	—	1	—	1
Fixed income securities:				
Short term investment fund	—	7	—	7
Mutual funds	5	—	—	5
	$ 6	$ 10	$ —	$ 16

(1) Mutual funds: a combination of small capitalization growth equity and medium and long duration fixed income funds which can invest across all of the major fixed income sectors. These mutual funds are actively managed.
(2) Private equity: 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.
(3) Portable alpha: an investment mandate comprised of long position 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.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(continued)

	As of December 31, 2009			
	Level 1	**Level 2**	**Level 3**	**Total**
Defined Benefit Pension Plan assets:				
Equity securities:				
U.S. small cap core	$ 11	$ —	$ —	$ 11
U.S. small cap value	12	—	—	12
U.S. micro cap	12	—	—	12
U.S. large cap growth	—	24	—	24
U.S. large cap value	—	23	—	23
Large cap long/short	—	47	—	47
International large cap growth	—	46	—	46
Fixed income securities:				
U.S. core plus	—	34	—	34
U.S. long government/credit	—	32	—	32
Short duration	—	2	—	2
Mutual funds (1)	123	—	—	123
Private equity funds (2)	—	—	17	17
U.S. large cap futures and U.S. hedge funds (3)	—	—	23	23
	$ 158	$ 208	$ 40	$ 406
Other Postretirement Benefit Plans assets:				
Equity securities:				
U.S. small cap core	$ 1	$ —	$ —	$ 1
U.S. large cap growth	—	2	—	2
U.S. large cap value	—	1	—	1
International large cap growth	—	1	—	1
Fixed income securities:				
Short term investment fund	—	7	—	7
Mutual funds	7	—	—	7
	$ 8	$ 11	$ —	$ 19

(1) Mutual funds: a combination of small capitalization growth equity and medium and long duration fixed income funds which can invest across all of the major fixed income sectors. These mutual funds are actively managed.

(2) Private equity: 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.

(3) Portable alpha: an investment mandate comprised of long position 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.

For information concerning the valuation techniques used to measure fair value presented in the preceding tables, see Note 4, Fair Value of Financial Instruments, and the Levels 1, 2, and 3 discussion.

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 years ended December 31, 2010 and 2009 (in millions):

	Private equity	U.S. Large Cap and U.S. Hedge Funds	Total Level 3
Balance as of December 31, 2008	$ 16	$ 18	$ 34
Purchases and sales	1	1	2
Unrealized gain on assets	—	4	4
Balance as of December 31, 2009	17	23	40
Purchases and sales	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

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, 2010 and 2009. Obligations related to the Other NQBP, which includes deferred compensation programs and split dollar life insurance for certain employees, are not included in the following tables (dollars in millions):

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2010	2009	2010	2009	2010	2009
Benefit obligation:						
As of January 1	$ 491	$ 467	$ 77	$ 73	$ 27	$ 25
Service cost	11	11	2	2	—	—
Interest cost	28	31	4	4	1	2
Plan amendments	—	1	—	—	—	—
Participants' contributions	—	—	2	2	—	—
Actuarial loss	42	5	1	2	—	2
Benefit payments	(22)	(24)	(7)	(6)	(3)	(2)
As of December 31	$ 550	$ 491	$ 79	$ 77	$ 25	$ 27
Fair value of plan assets:						
As of January 1	$ 406	$ 347	$ 19	$ 19	$ 20	$ 18
Actual return on plan assets	59	83	1	3	2	4
Company contributions	30	—	1	1	—	—
Participants' contributions	—	—	2	2	—	—
Benefit payments	(22)	(24)	(7)	(6)	(3)	(2)
As of December 31	$ 473	$ 406	$ 16	$ 19	$ 19	$ 20
Unfunded position as of December 31	$ (77)	$ (85)	$ (63)	$ (58)	$ (6)	$ (7)
Accumulated benefit plan obligation as of December 31	$ 503	$ 446	N/A	N/A	$ 25	$ 26
Classification in consolidated balance sheet:						
Noncurrent asset	$ —	$ —	$ —	$ —	$ 19	$ 20
Current liability	—	—	—	—	(2)	(2)
Noncurrent liability	(77)	(85)	(63)	(58)	(23)	(25)
Net liability	$ (77)	$ (85)	$ (63)	$ (58)	$ (6)	$ (7)

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2010	2009	2010	2009	2010	2009
Amounts included in comprehensive income:						
Net actuarial (gain) loss	$ 22	$ (35)	$ 1	$ —	$ —	$ 2
Prior service cost	—	1	—	—	—	—
Amortization of net actuarial loss	(3)	—	(1)	(1)	(1)	—
Amortization of prior service cost	(1)	(1)	(1)	(1)	—	—
	$ 18	$ (35)	$ (1)	$ (2)	$ (1)	$ 2
Amounts included in AOCL*:						
Net actuarial loss	$ 186	$ 167	$ 20	$ 20	$ 9	$ 9
Prior service cost	2	3	5	6	—	—
	$ 188	$ 170	$ 25	$ 26	$ 9	$ 9
Assumptions used:						
Average discount rate used to calculate benefit obligation	5.47%	5.90%	4.02% - 5.40%	4.66% - 5.92%	5.47%	5.90%
Weighted average rate of increase in future compensation levels	3.80%	3.79%	4.83%	5.07%	N/A	N/A
Long-term rate of return on plan assets	8.50%	8.50%	6.44%	6.88%	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		
	2010	2009	2008	2010	2009	2008	2010	2009	2008
Service cost	$ 11	$ 11	$ 12	$ 2	$ 2	$ 2	$ —	$ —	$ —
Interest cost on benefit obligation	28	31	30	4	4	4	1	2	2
Expected return on plan assets	(39)	(43)	(45)	(1)	(1)	(2)	—	—	—
Amortization of transition obligation	—	—	—	—	—	1	—	—	—
Amortization of prior service cost	1	1	1	1	1	1	—	—	—
Amortization of net actuarial loss	3	—	—	1	1	—	1	—	—
Net periodic benefit cost	$ 4	$ —	$ (2)	$ 7	$ 7	$ 6	$ 2	$ 2	$ 2

PGE estimates that $12 million will be amortized from AOCL into net periodic benefit cost in 2011, consisting of a net actuarial loss of $8 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 pension benefits and $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					
	2011	2012	2013	2014	2015	2016 - 2020
Defined benefit pension plan	$ 27	$ 31	$ 32	$ 33	$ 35	$ 196
Other postretirement benefits	5	5	5	6	6	28
Non-qualified benefit plans	2	2	2	3	2	11
Total	$ 34	$ 38	$ 39	$ 42	$ 43	$ 235

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 2010, 8% annual rate of increase in the per capita cost of covered health care benefits is assumed for 2011 through 2013, and assumed to decrease 0.5% per year thereafter, reaching 5% in 2019;
- For 2009, 7.5% annual rate of increase in the per capita cost of covered health care benefits is assumed for 2010, and assumed to decrease 0.5% per year thereafter, reaching 5% in 2015; and
- For 2008, 8% annual rate of increase in the per capita cost of covered health care benefits is assumed for 2009, and assumed to decrease 0.5% per year thereafter, reaching 5% in 2015.

A one-percentage point increase or decrease in the above health care cost assumption would not have a material impact on total service or interest cost, but would increase or decrease the postretirement benefit obligation by $1 million.

401(k) Retirement Savings Plan

PGE sponsors a 401(k) Plan, which covers substantially all employees. For eligible employees hired prior to February 1, 2009, employee contributions to the 401(k) Plan, made on a “pre-tax” basis, are matched by the Company up to 6% of base pay. For contributions made by eligible employees hired after January 31, 2009, and/or who are not covered by a defined benefit pension plan, the Company will match up to 5% of the participating employee’s base salary. In addition, PGE makes an additional 5% contribution for these employees regardless of whether or not the employees make a contribution.

For bargaining employees, contributions are based upon provisions of the International Brotherhood of Electrical Workers Local 125 agreement that became effective on March 1, 2009. The following additions were made to the 401(k) plan for active bargaining employees:

- Effective March 4, 2009, the $0.50 per compensable hour contribution, previously deposited into the employee’s HRA, is re-directed to the participants’ 401(k) plan. This contribution to the participants’ 401(k) plan will increase to $1.00 per compensable hour effective November 1, 2011.

- Effective March 3, 2010, employees received an additional 1% Company contribution based on the employee's base salary. This is a Company contribution regardless of whether or not the employee makes a contribution.

All contributions are invested in accordance with employees' elections, limited to investment options available under the 401(k) Plan. PGE made contributions of approximately $15 million during the year ended December 31, 2010 and contributions of $14 million during each of the years ended December 31, 2009 and 2008.

NOTE 11: INCOME TAXES

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

	Years Ended December 31,		
	2010	2009	2008
Current:			
Federal	$ (20)	$ (46)	$ 12
State and local	—	—	1
	(20)	(46)	13
Deferred:			
Federal	61	78	20
State and local	12	6	4
	73	84	24
Investment tax credit adjustments	—	(2)	(2)
Income tax expense	$ 53	$ 36	$ 35

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,		
	2010	2009	2008
Federal statutory tax rate	35.0%	35.0%	35.0%
Federal tax credits	(10.4)	(8.3)	(6.6)
State and local taxes, net of federal tax benefit	4.4	3.4	1.4
Flow through depreciation and cost basis differences	0.1	(1.6)	(0.8)
Investment tax credit amortization	—	(1.5)	(1.6)
Other	1.2	1.8	1.0
Effective tax rate	30.3%	28.8%	28.4%

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

	As of December 31, 2010	2009
Deferred income tax assets:		
Regulatory liabilities	$ 331	$ 278
Tax credits, net of valuation allowance	40	5
Employee benefits	24	39
Tax loss carryforwards	17	2
Other	5	—
Total deferred income tax assets	417	324
Deferred income tax liabilities:		
Depreciation and amortization	754	620
Regulatory assets	109	37
Price risk management	3	19
Other	—	23
Total deferred income tax liabilities	866	699
Deferred income tax liability, net	$ (449)	$ (375)
Classification of net deferred income taxes:		
Current deferred income tax liability *	$ (4)	$ (19)
Noncurrent deferred income tax liability	(445)	(356)
	$ (449)	$ (375)

* Included in Other current liabilities in the consolidated balance sheets.

As of December 31, 2010, PGE had federal and state loss carryforwards of $13 million and $4 million, respectively, which will expire at various dates from 2015 through 2030. In addition, PGE has federal and state tax credit carryforwards of $31 million and $9 million, respectively, which will expire at various dates from 2011 through 2030. PGE believes that it is more likely than not that the benefit from certain state credit carryforwards will not be realized. In recognition of this risk, we have provided a valuation allowance of $2 million on the deferred tax assets relating to these state credit carryforwards as of December 31, 2010. The net change in the total valuation allowance for the year ended December 31, 2010 was a decrease of approximately $1 million. If the Company's assumptions change and it determines it will be able to realize these credits, the tax benefits relating to any reversal of the valuation allowance on deferred tax assets as of December 31, 2010 will be accounted for as a reduction in income tax expense.

PGE generated approximately $13 million of Oregon tax credits that, due to taxable income limitations, were not utilized by Enron (former parent company of PGE) prior to the separation of the two companies on April 3, 2006. Prior to 2006, pursuant to a tax sharing agreement, PGE utilized these tax credits to reduce its tax payment obligations to Enron. In 2008, PGE made an assessment that it is remote that Enron will be able to utilize these tax credits. Therefore, the realization of such tax credits by PGE was reflected as an adjustment to equity, net of the related federal tax effect, during the year ended December 31, 2008.

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. PGE recognizes interest and penalties related to its unrecognized tax benefits in its consolidated statements of income. During the year ended December 31, 2010, the Company recognized $1 million in interest and no penalties. PGE believes that it is reasonable that its unrecognized tax benefit will be recognized by the end of 2011 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) performed an examination of PGE's income tax returns for 2007 and 2008 during 2010. This audit closed in the first quarter of 2011, with no material findings. In addition, the IRS has informed PGE that examination of the 2006, 2009, and 2010 income tax returns will commence in the third quarter of 2011. The Company is not currently under examination by state or local tax authorities.

NOTE 12: EMPLOYEE STOCK PURCHASE PLAN

PGE has an employee stock purchase plan (ESPP), under which a total of 625,000 shares of the Company 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 market value on the purchase date) or 1,500 shares, whichever is less. There are two six-month offering periods each year, January 1 - June 30 and July 1 - December 31, during which eligible employees may purchase shares of PGE common stock at a price equal to 95% of the fair market value of the stock on the purchase date, the last day of the offering period. During the years ended December 31, 2010, 2009, and 2008, the Company issued 28,558 shares, 29,648 shares, and 25,586 shares, respectively, under the ESPP, with proceeds totaling approximately $0.5 million, $0.6 million, and $0.5 million, respectively.

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 3,975,124 shares remain available for future issuance as of December 31, 2010.

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. Performance goals include a return on equity measure and a regulated asset base growth measure. 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, in determining results relative to these goals, the committee may disregard or offset the effect of extraordinary, unusual or non-recurring items. 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, which is an amount equal to dividends paid to shareholders on a share of PGE's common stock. The DERs vest on the same schedule as the stock units and 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.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(continued)

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

	Units	Weighted Average Grant Date Fair Value
Outstanding as of December 31, 2007	253,251	$ 26.28
Granted	133,199	22.66
Forfeited	(3,392)	25.02
Vested	(22,676)	24.87
Outstanding as of December 31, 2008	360,382	25.04
Granted	243,574	14.95
Forfeited	(4,847)	24.85
Vested	(176,846)	23.60
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

The vesting of Restricted and Performance Stock Units presented in the table above differ from the number of shares issued for the vesting of restricted stock units on the consolidated statements of equity because of the payment of income taxes on behalf of the employees, in the form of shares, and the vesting of DERs, which totaled 25,942 shares in 2010, 48,671 shares in 2009, and 2,792 shares in 2008. The total value of Restricted and Performance Stock Units vested during the years ended December 31, 2010, 2009, and 2008 was $2.7 million, $4.2 million and $0.6 million, respectively.The weighted average fair value is measured based on the closing price of PGE common stock on the date of grant. For the years ended December 31, 2010, 2009, and 2008, PGE recorded $2 million, $1.4 million and $4 million, respectively, of stock-based compensation expense, which is included in Administrative and other expense in the consolidated statements of income. The recorded stock-based compensation expense of $2 million for 2010 and $1.4 million for 2009 is different than the amount 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 $0.5 million in 2010 and $1 million in 2009 not reported in Administrative and other expenses in the consolidated statements of income.

As of December 31, 2010, unrecognized stock-based compensation expense was $2.9 million, of which $1.9 million and $1 million is expected to be expensed in 2011 and 2012, respectively. Stock-based compensation expense was calculated assuming the attainment of performance goals that would allow the vesting of 94.2%, 81.2%, and 0% of awarded Performance Stock Units for 2010, 2009, and 2008, respectively, with an estimated 6% forfeiture rate. No stock-based compensation costs have been capitalized and the plan had no material impact on cash flow for the years ended December 31, 2010, 2009, or 2008.

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. Unvested Performance Stock Units and related DERs are not included in the computation of dilutive securities because vesting of these instruments is dependent upon three-year performance periods.

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

	Years Ended December 31,		
	2010	**2009**	**2008**
Numerator (in millions):			
Net income attributable to Portland General Electric Company common shareholders	$ 125	$ 95	$ 87
Denominator (in thousands):			
Weighted average common shares outstanding—basic	75,275	72,790	62,544
Dilutive effect of unvested restricted stock units and employee stock purchase plan shares	16	62	37
Weighted average common shares outstanding—diluted	75,291	72,852	62,581
Earnings per share basic and diluted	$ 1.66	$ 1.31	$ 1.39

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, 2010, PGE's future minimum payments pursuant to purchase obligations for the following five years and thereafter are as follows (in millions):

	Payments Due						
	2011	2012	2013	2014	2015	Thereafter	Total
Capital and other purchase commitments	$ 136	$ 15	$ 13	$ 6	$ 6	$ 26	$ 202
Purchased power and fuel:							
Electricity purchases	111	70	69	66	65	416	797
Capacity contracts	21	20	20	20	19	19	119
Public Utility Districts	9	7	8	8	8	49	89
Natural gas	69	25	20	17	16	16	163
Coal and transportation	21	4	3	—	—	—	28
Operating leases	10	10	10	10	10	202	252
Total	$ 377	$ 151	$ 143	$ 127	$ 124	$ 728	$ 1,650

Capital and other purchase commitments—Certain commitments have been made for capital and other purchases for 2011 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 2036, and power capacity contracts through 2016. As of December 31, 2010, PGE has power sale contracts with counterparties of approximately $9 million in 2011 and $4 million in 2012.

PGE has two long-term power exchange contracts. One exchange contract is with a summer-peaking California utility to help meet the Company's winter-peaking power requirements and expires in 2012. As of December 31, 2010, there was no outstanding exchange balance pursuant to this exchange contract. The other exchange contract is with a winter-peaking Northwest utility to help meet the Company's summer-peaking power requirements and expires in 2011. As of December 31, 2010, PGE owed 4,191 MWh of electricity, all of which is expected to be delivered by the end of February 2011.

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 table above 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, 2010	PGE Share		Contract Expiration	PGE Cost, including Debt Service		
		Output	Capacity (in MW)		2010	2009	2008
Rocky Reach	$ 329	12.0%	156	2011	$ 9	$ 8	$ 9
Priest Rapids and Wanapum	907	9.6	192	2052	10	17	14
Wells	263	19.4	159	2018	7	8	8
Portland Hydro	13	100.0	36	2017	4	4	3

Under contracts with the public utility districts, PGE has acquired a percentage of the output (Allocation) of Rocky Reach, 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 Rocky Reach and 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, which expire at various dates through 2013.

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 (1) the corporate headquarters lease, which expires in 2018, but includes renewal period options through 2043, and (2) the Port of St. Helens land lease, where PGE's Beaver and Port Westward generating plants operate, which expires in 2096. Rent expense was $9 million in 2010, $7 million in 2009, and $8 million in 2008.

The future minimum operating lease payments presented is net of sublease income of $3 million in 2011, $2 million in 2012 and 2013, and $1 million in 2014 and 2015. Sublease income is classified as Miscellaneous income in the consolidated statements of income and was $3 million in 2010, 2009, and 2008.

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 P&T Agreements expire on December 31, 2013. 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 2011 is approximately $100 million. Management believes that circumstances that could result in such amount, or any lesser amount, being owed by the Company are remote.

PGE enters into financial agreements and power purchase and sale agreements that include indemnification provisions relating to certain claims or liabilities that may arise relating to the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and therefore, the overall maximum amount of the obligation under such indemnifications cannot be reasonably estimated. PGE periodically evaluates the likelihood of incurring costs under such indemnities based on PGE's historical experience and the evaluation of the specific indemnities. As of December 31, 2010, management believes the likelihood is remote that PGE would be required to perform 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 indemnifications.

NOTE 16: VARIABLE INTEREST ENTITIES

PGE has determined that its interest in three VIEs, as outlined below, contains the obligation to absorb the variability of the entities that could potentially be significant to the VIEs, and the power to direct the activities that most significantly affect the entities' economic performance. Accordingly, the VIEs are consolidated 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. These facilities can generate up to an aggregate of approximately 3.6 MW of electricity.

PGE is the Managing Member in each of the LLCs, holding less than 1% equity interest in each entity, and a financial institution is the Investor Member, holding more than 99% equity interest in each entity. PGE operates and manages the LLCs pursuant to an operating agreement, which provides PGE with decision making authority without substantive kick-out rights. The operating agreements also provide for the flip of ownership interests upon the culmination of certain events, one of which is the passing of five years. Following the flip, PGE will own 95% of the respective LLCs and the Investor Member will own 5%, without the exchange of any additional consideration. PGE expects to purchase the residual 5% interest from the Investor Member at the then fair market value of the Investor Member's interest.

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: (1) 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; (2) 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 (3) based on projections prepared in accordance with the operating agreement, PGE expects to absorb a majority of the expected losses of the LLCs.

During 2010, an impairment loss of $4 million, which is classified in Depreciation and amortization expense, was recognized on the photovoltaic solar power facility held by one of the LLCs. Based on PGE's intent to ultimately acquire 100% of the LLCs and the fact that the capitalized cost of the photovoltaic solar power facility exceeded the undiscounted cash flows of the facility over its estimated useful live, an impairment analysis was performed. The impairment loss was equal to the excess of the carrying amount over the estimated fair value of the photovoltaic solar power facility. The carrying amount of this photovoltaic solar power facility reflected the accrual of a federal renewable energy grant under the American Recovery and Reinvestment Act of 2009 of $4.1 million, which is expected to be received in 2011. 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 life of 20 years. The new cost basis of the photovoltaic solar power facility is amortized over its remaining estimated useful life. 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. During 2009, impairment losses of $5 million were recognized on the photovoltaic solar power facilities held by the other two LLCs.

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.

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

	As of December 31,	
	2010	**2009**
Cash and cash equivalents	$ 1	$ —
Accounts receivable	4	—
Electric utility plant, net	5	1

These assets can only be used to settle the obligations of the consolidated VIEs.

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, 2010, 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	$ 439	$ 280	$ 8
Colstrip	20.00%	1986	497	322	5
Pelton/Round Butte	66.67%	1958/1964	211	43	9
Total			$ 1,147	$ 645	$ 22

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

NOTE 18: CONTINGENCIES

Trojan Investment Recovery

Background. 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.

Court Proceedings on OPUC Authority to Grant Recovery of Return on Trojan Investment. Numerous challenges, appeals and reviews 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. The primary plaintiffs in the litigation were the CUB and the Utility Reform Project (URP). 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, CUB, and the staff of the OPUC entered into agreements to settle the litigation related to PGE's recovery of, and return on, its investment in Trojan. The URP did not participate in the settlement and filed a complaint with the OPUC challenging the settlement agreements. In March 2002, the OPUC issued an order (2002 Order) denying all of the URP's challenges, and approving the accounting and ratemaking elements of the 2000 settlement. In October 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.

On September 30, 2008, the OPUC issued an order that required PGE to refund $15.4 million, plus interest at 9.6% from September 30, 2000, to customers who received service from PGE during the period October 1, 2000 to September 30, 2001. The $15.4 million amount, plus accrued interest, resulted in a total refund of $33.1 million, payment of which was completed in the first quarter of 2010. The URP and the plaintiffs in the class actions described below have separately appealed the order to the Oregon Court of Appeals.

Class Actions. In a separate legal proceeding, two class action suits were filed in Marion County Circuit Court against PGE in 2003 on behalf of two classes of electric service customers (the Class Action Plaintiffs). The lawsuits seek damages of $260 million plus interest as a result of the inclusion of a return on investment of Trojan in the prices PGE charged its customers.

In August 2006, the Oregon Supreme Court issued a ruling ordering the abatement of the class action proceedings until the OPUC responded to the 2002 Order (described above). The Oregon Supreme Court concluded that the OPUC has primary jurisdiction to determine what, if any, remedy it can offer to PGE customers, through price reductions or refunds, for any amount of return on the Trojan investment PGE collected in prices for the period from April 1, 1995 through October 1, 2000.

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

In October 2006, the Marion County Circuit Court abated the class actions in response to the ruling of the Oregon Supreme Court. In October 2007, the Class Action Plaintiffs filed a motion to lift the abatement. In February 2009, the Circuit Court judge denied the motion.

Management cannot predict the ultimate outcome of the above matters. Management believes, however, that these matters will not have a material adverse impact on the financial condition of the Company, but may have a material adverse impact on the results of operations and cash flows in future reporting periods.

Complaint and Application for Deferral—Income Taxes

In October 2005, the URP and another party (together, the Complainants) filed a Complaint and an Application for Deferred Accounting with the OPUC alleging that, since the September 2, 2005 effective date of SB 408, PGE's rates were not just and reasonable and were in violation of SB 408 because they contained approximately $92.6 million in annual charges for state and federal income taxes that were not paid to any governmental entity. The Complaint and Application for Deferred Accounting requested that the OPUC order the creation of a deferred account for all amounts charged to customers since September 2, 2005 for state and federal income taxes, less amounts actually paid by or on behalf of PGE to the federal and state governments for income taxes.

In August 2007, the OPUC issued an order granting the Application for Deferred Accounting for the period from October 5, 2005 through December 31, 2005 (Deferral Period). The OPUC's order also dismissed the Complaint on grounds that it was superfluous to the Complainants' Application for Deferred Accounting. The order required that PGE calculate the amounts applicable to the Deferral Period, along with calculations of PGE's earnings and the effect of the deferral on the Company's return on equity.

In December 2007, PGE filed its report as required by the OPUC. In the report, PGE determined that (i) the amount of any deferral would be between zero and $26.6 million; and (ii) PGE's earnings over the twelve-month period ended September 30, 2006 would preclude any refund.

In August 2009, the OPUC issued an order that denied amortization of any deferral in this matter, based on a review of PGE's earnings over the 12-month period ended September 30, 2006.

In October 2009, plaintiffs filed an appeal of the August 2009 order with the Oregon Court of Appeals.

Management cannot predict the ultimate outcome of this matter. Management believes, however, that this matter will not have a material adverse effect on PGE's financial condition, results of operations or cash flows.

Turlock Irrigation District Claim

PGE and Power Resources Cooperative (PRC) are parties to an Ownership and Operation Agreement (OOA), pursuant to which PRC is entitled to ten percent of the power generated at Boardman. In 1992, PRC entered into a power purchase agreement with Turlock Irrigation District (Turlock) in which PRC agreed to provide Turlock with its share of the Boardman output. In October 2005, Boardman experienced an outage that extended into 2006.

Turlock subsequently filed a lawsuit against PGE in Multnomah County Circuit Court in the state of Oregon, alleging breach of contract, negligence, and gross negligence, seeking damages in excess of $15 million as a result of having to purchase power in the open market to replace lost output from Boardman during the outage. The complaint further alleges that PRC assigned its litigation rights relating to the outage to Turlock pursuant to an assignment agreement executed in 2007.

PGE sought and received an order joining PRC as a necessary party to the litigation. PRC intervened as a plaintiff, also alleging breach of contract and damages in the amount alleged by Turlock, for the purpose of reimbursing Turlock for those expenses.

In August 2009, PGE filed a motion for summary judgment, alleging that Turlock lacked standing to bring a contract or tort claim against PGE, that damages based on economic loss are not recoverable under a tort claim, and that, under the OAA, the parties have waived their rights to bring tort claims based on the theory of negligence.

In November 2009, the Court denied PGE's motion for summary judgment and set a trial schedule. Subsequently, the trial date was removed from the docket as the parties have reached a tentative settlement, which is pending finalization.

Management cannot predict the outcome of this matter. Management believes, however, that the ultimate outcome will not have a material adverse impact on the Company's financial condition, results of operations or cash flows.

Lawsuit filed by Sierra Club and Other Environmental Groups

On September 30, 2008, the Sierra Club and other environmental groups filed suit against PGE in the U.S. District Court for the District of Oregon (Court) for alleged violations at PGE's Boardman Coal Plant of the federal Clean Air Act (CAA), Oregon's Regional Haze State Implementation Plan (SIP), the plant's CAA Title V permit, and additional alleged violations of various environmental related regulations.

The plaintiffs seek injunctive relief that includes permanently enjoining PGE from operating Boardman except in accordance with the CAA, Oregon's SIP, and the plant's Title V Permit. In addition, plaintiffs seek civil penalties against PGE including $27,500 per day per alleged violation for violations occurring before March 15, 2004 and $32,500 per day per alleged violation for those occurring thereafter. The total amount of monetary penalties and damages asserted in the complaint cannot be determined with certainty. However, based solely on the complaint, the Company estimates that the amount could be up to approximately $60 million.

On September 30, 2009, the Court ruled on PGE's motion to dismiss most of the claims. In summary, the court denied PGE's motion with respect to most of the plaintiff's claims, but granted PGE's motion with respect to certain claims. The principal claims that remain are (i) that PGE constructed Boardman without complying with the 1974 and 1977 federal pre-construction permitting requirements, (ii) that PGE modified Boardman in the 1990s without complying with Oregon's pre-construction permitting requirements, and (iii) that certain modifications to Boardman triggered New Source Performance Standards (NSPS). Discovery in the case continues, with a tentative trial date set for August 2011.

Management cannot predict the ultimate outcome of the above matters. Management believes, however, that these matters will not have a material adverse impact on the financial condition of the Company, but may have a material adverse impact on the results of operations and cash flows in future reporting periods.

EPA Notice of Violation

On September 28, 2010, PGE received a Notice of Violation (NOV) from the U.S. Environmental Protection Agency (EPA). The NOV states that the EPA has determined that PGE is violating the NSPS under the CAA, and Operating Permit requirements under Title V of the CAA, at the Boardman plant. In the NOV, the EPA asserts that certain projects at the Boardman plant completed in 1998 and in 2004 triggered the NSPS, that PGE did not meet the emissions standards required by the regulations and that, therefore, PGE has operated the boiler at the Boardman plant in violation of the CAA. The NOV states the maximum civil penalties the EPA is authorized to impose under the CAA for violations of the NSPS (which range from $25,000 to $37,500 per day), but does not impose any penalties, or specify the amount of any proposed penalties with respect to the alleged violations. Accordingly, management cannot estimate the range of potential liability for the violations asserted in the NOV. However, based solely on the maximum penalties authorized under the CAA, management believes that the maximum penalty that could be imposed for the alleged violations would be approximately $60 million. The projects alleged to have triggered NSPS in the NOV are also included in the Sierra Club’s NSPS claims in the litigation described above. Accordingly, to the extent the Company incurs liability for such claims in connection with one of these proceedings, liability for the same claims could not be imposed pursuant to the other proceeding. In the NOV, the EPA has offered PGE an opportunity to confer with the EPA about the violations cited and to present information on the specific findings of the EPA. PGE expects to meet with the EPA during the first quarter of 2011.

Management cannot predict the ultimate outcome of the above matters. Management believes, however, that these matters will not have a material adverse impact on the financial condition of the Company, but may have a material adverse impact on the results of operations and cash flows in future reporting periods.

Pacific Northwest Refund Proceeding

In July 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 June 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 its potential ties to the Pacific Northwest and that the FERC should not have excluded from the Pacific Northwest Refund proceeding purchases of energy made by the California Energy Resources Scheduling (CERS) division in the Pacific Northwest spot market. The Ninth Circuit remanded the case to the FERC to (i) address the new market manipulation evidence in detail and account for it 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.

Since issuance of the mandate, certain parties proposing refunds have filed pleadings with the FERC suggesting procedures on remand, attempting to initiate new proceedings, and containing additional evidence that they assert shows market-wide manipulation that justifies refunds from early in 2000. Parties opposing refunds, including PGE, have filed various pleadings that contest allegations of market-wide manipulation and urge the FERC to reaffirm, with a more detailed explanation of its consideration of market manipulation claims, its previous decision not to initiate proceedings to order refunds.

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 as to transactions in the Pacific Northwest during the settlement period, January 1, 2000 through

June 21, 2001, but did not settle potential claims from other market participants relating to transactions in the Pacific Northwest.

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

EPA Investigation of Portland Harbor

A 1997 investigation by the EPA of a segment of the Willamette River known as the Portland Harbor revealed significant contamination of river sediments. The EPA subsequently included Portland Harbor on the federal National Priority List pursuant to the federal Comprehensive Environmental Response, Compensation, and Liability Act as a federal Superfund site and listed 69 Potentially Responsible Parties (PRPs). PGE was included among the PRPs as it has historically owned or operated property near the river.

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

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

The EPA will determine the boundaries of the site at the conclusion of the RI/FS in a Record of Decision in which it will document its findings and select a preferred cleanup alternative. The EPA expects to issue the Record of Decision in 2012.

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

EPA Investigation of Harbor Oil

Harbor Oil, Inc. (Harbor Oil), located in north Portland, was utilized by PGE to process used oil from the Company's power plants and electrical distribution system from at least 1990 until 2003. Harbor Oil continues to be utilized by other entities for the processing of used oil and other lubricants.

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

PGE received a Special Notice Letter for RI/FS from the EPA, dated June 27, 2005, in which the Company was named as one of fourteen PRPs with respect to the Harbor Oil site. In May 2007, an AOC was signed by the EPA and six other parties, including PGE, to implement an RI/FS at the Harbor Oil site. The draft remedial investigation was completed with the resulting report submitted to the EPA.

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

Other Matters

PGE is subject to other regulatory, environmental, and legal proceedings that arise from time to time in the ordinary course of its business, which may result in adverse judgments against the Company. Although management currently believes that resolution of such matters will not have a material adverse 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)			
2010				
Revenues, net [1]	$ 449	$ 415	$ 464	$ 455
Income from operations [1]	61	57	90	59
Net income [1]	27	24	48	22
Net income attributable to Portland General Electric Company [1]	27	24	49	25
Earnings per share—basic and diluted [1] [2]	0.36	0.32	0.65	0.34
2009				
Revenues, net	$ 485	$ 389	$ 445	$ 485
Income from operations [3] [4]	63	45	62	38
Net income [3] [4]	24	26	31	8
Net income attributable to Portland General Electric Company [3] [4]	31	24	32	8
Earnings per share—basic and diluted [2] [3] [4]	0.47	0.31	0.43	0.11

(1) Revenues for the fourth quarter of 2010 include the reversal of an estimated collection from customers that had been recorded as of September 30, 2010 in the amount of $24 million related to SB 408 for 2010.

(2) 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.

(3) Production and distribution expense for the fourth quarter of 2009 includes $6 million of capital costs related to the Company’s Selective Water Withdrawal project pursuant to a stipulation with the OPUC.

(4) Income from operations for the fourth quarter of 2009 includes an $18 million expense related to the write-off of a portion of deferred excess replacement power costs associated with the extended forced outage of Boardman from November 5, 2005 through February 5, 2006. This resulted in a reduction of $11 million in both Net income and Net income attributable to Portland General Electric Company in the fourth quarter of 2009, reducing earnings per share by $0.14.

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 such term is 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 in recording, processing, summarizing and reporting, on a timely basis, the information relating to the Company (including its consolidated subsidiaries) required to be disclosed by the Company in the reports that it files or submits under the Exchange Act and are effective in ensuring that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is accumulated and communicated to the Company's management, including the Company's Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

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

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting (as such term is 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.

The Company's internal control over financial reporting includes policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and disposition of the assets; provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures are being made only in accordance with authorizations of management and the directors of the Company; and 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 Company's financial statements.

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, 2010, the Company's internal control over financial reporting is effective.

The Company's internal control over financial reporting, as of December 31, 2010, 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, 2010.

(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 2010 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—The Board 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 11, 2011.

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 11, 2011.

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 11, 2011.

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 11, 2011.

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 11, 2011.

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*	Seventh Amended and Restated Bylaws of Portland General Electric Company (Form 8-K filed February 19, 2010, 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).
4.2*	Fortieth Supplemental Indenture dated October 1, 1990 (Form 10-K for the year ended December 31, 1990, Exhibit 4) (File No. 1-05532-99).
4.3*	Fifty-sixth Supplemental Indenture dated May 1, 2006 (Form 8-K filed May 25, 2006, Exhibit 4.1).
4.4*	Fifty-seventh Supplemental Indenture dated December 1, 2006 (Form 8-K filed December 22, 2006, Exhibit 4.1).
4.5*	Fifty-eighth Supplemental Indenture dated April 1, 2007 (Form 8-K filed April 12, 2007, Exhibit 4.1).
4.6*	Fifty-ninth Supplemental Indenture dated October 1, 2007 (Form 8-K filed October 5, 2007, Exhibit 4.1).
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*	Separation Agreement between Enron Corp. and Portland General Electric Company dated April 3, 2006 (Form 8-K filed April 3, 2006, Exhibit 10.1).
10.2*	Five Year Credit Agreement dated May 27, 2005, between Portland General Electric Company, JP Morgan Chase Bank, N.A., as Administrative Agent, and a group of lenders (Form 8-K filed June 2, 2005, Exhibit 4.1).
10.3*	Credit Agreement dated December 4, 2009, between Portland General Electric Company, Bank of America N.A., as Administrative Agent, and a group of lenders (Form 8-K filed December 8, 2009, Exhibit 4.1).

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Exhibit Number	Description
	Exhibits 10.4 through 10.15 were filed in connection with the Company's 1985 Boardman/Intertie Sale:
10.4*	Long-term Power Sale Agreement dated November 5, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.5*	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).
10.6*	Participation Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.7*	Lease Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.8*	PGE-Lessee Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.9*	Asset Sales Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.10*	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. 1-05532).
10.11*	Supplemental Bill of Sale dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.12*	Trust Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.13*	Tax Indemnification Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.14*	Trust Indenture, Mortgage and Security Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.15*	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. 1-05532).
10.16*	Portland General Electric Company Severance Pay Plan for Executive Employees dated June 15, 2005 (Form 8-K filed June 20, 2005, Exhibit 10.1). +
10.17*	Portland General Electric Company Outplacement Assistance Plan dated June 15, 2005 (Form 8-K filed June 20, 2005, Exhibit 10.2). +
10.18*	Portland General Electric Company 2005 Management Deferred Compensation Plan dated January 1, 2005 (Form 10-K filed March 11, 2005, Exhibit 10.18). +
10.19*	Portland General Electric Company Management Deferred Compensation Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.1). +
10.20*	Portland General Electric Company Supplemental Executive Retirement Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.2). +
10.21*	Portland General Electric Company Senior Officers' Life Insurance Benefit Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.3). +
10.22*	Portland General Electric Company Umbrella Trust for Management dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.4). +
10.23*	Portland General Electric Company 2006 Stock Incentive Plan, as amended (Form 10-K filed February 27, 2008, Exhibit 10.23). +

Exhibit Number	Description
10.24*	Portland General Electric Company 2006 Annual Cash Incentive Master Plan (Form 8-K filed March 17, 2006, Exhibit 10.1). +
10.25*	Portland General Electric Company 2006 Outside Directors’ Deferred Compensation Plan (Form 8-K filed May 17, 2006, Exhibit 10.1). +
10.26*	Portland General Electric Company 2008 Annual Cash Incentive Master Plan for Executive Officers (Form 8-K filed February 26, 2008, Exhibit 10.1). +
10.27*	Form of Portland General Electric Company Agreement Concerning Indemnification and Related Matters (Form 8-K filed December 24, 2009, Exhibit 10.1). +
10.28*	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). +
10.29*	Form of Directors’ Restricted Stock Unit Agreement (Form 8-K filed July 14, 2006, Exhibit 10.1). +
10.30*	Form of Officers’ and Key Employees’ Performance Stock Unit Agreement (Form 8-K filed March 13, 2008, Exhibit 10.1). +
10.31*	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.

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

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

Upon written request to Investor Relations, Portland General Electric Company, 121 SW Salmon Street, Portland, Oregon 97204, PGE 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 24, 2011.

PORTLAND GENERAL ELECTRIC COMPANY

By: /s/ JAMES J. PIRO

James J. Piro

President and Chief Executive Officer

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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 24, 2011.

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/ DAVID A. DIETZLER **David A. Dietzler**	*Director*
/s/ KIRBY A. DYESS **Kirby A. Dyess**	*Director*
/s/ PEGGY Y. FOWLER **Peggy Y. Fowler**	*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*

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EXHIBIT 12.1

PORTLAND GENERAL ELECTRIC COMPANY
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

	Years Ended December 31,				
	2010	**2009**	**2008**	**2007**	**2006**
	(Dollars in thousands)				
Income from continuing operations before income taxes	$ 178,158	$ 131,636	$ 121,825	$ 220,123	$ 107,240
Total fixed charges	131,486	129,948	111,589	98,682	91,846
Total earnings	$ 309,644	$ 261,584	$ 233,414	$ 318,805	$ 199,086
Fixed charges:					
Interest expense	$ 110,240	$ 103,389	$ 90,257	$ 74,362	$ 68,932
Capitalized interest	9,097	11,816	6,184	9,596	8,482
Interest on certain long-term power contracts	8,068	10,038	10,010	9,552	9,927
Estimated interest factor in rental expense	4,081	4,705	5,138	5,172	4,505
Total fixed charges	$ 131,486	$ 129,948	$ 111,589	$ 98,682	$ 91,846
Ratio of earnings to fixed charges	2.35	2.01	2.09	3.23	2.17

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 24, 2011, relating to the consolidated financial statements of Portland General Electric Company, 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, 2010.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 24, 2011

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 24, 2011

/s/ JAMES J. PIRO

James J. Piro

Chief Executive Officer and

President

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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 24, 2011

/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, Chief Executive Officer and President, 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, 2010, as filed with the Securities and Exchange Commission on February 25, 2011 pursuant to Section 13(a) of the Securities Exchange Act of 1934 (the "Report"), fully complies with the requirements of that section.

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

/s/ JAMES J. PIRO	/s/ MARIA M. POPE
James J. Piro	**Maria M. Pope**
Chief Executive Officer and President	*Senior Vice President, Finance, Chief Financial Officer, and Treasurer*
Date: February 24, 2011	Date: February 24, 2011