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

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2008

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
(Title of class)

New York Stock Exchange
(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 ☒ 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 ☒

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 ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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. ☐

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. (Check one):

Large accelerated filer	☒	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 ☒

As of June 30, 2008, the aggregate market value of voting common stock held by non-affiliates of the Registrant was $1,407,939,478. For purposes of this calculation, executive officers and directors are considered affiliates.

As of February 18, 2009, there were 62,575,257 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 2009 Annual Meeting of Shareholders to be held on May 13, 2009.

PORTLAND GENERAL ELECTRIC COMPANY
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2008

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DEFINITIONS

The following abbreviations or acronyms used in the text and Notes to Consolidated Financial Statements are defined below:

Abbreviation or Acronym	Definition
AFDC	Allowance for funds used during construction
Beaver	Beaver generating plant
Biglow Canyon	Biglow Canyon Wind Farm
Boardman	Boardman coal plant
BPA	Bonneville Power Administration
CERS	California Energy Resources Scheduling
Colstrip	Colstrip Units 3 and 4 coal plant
Coyote Springs	Coyote Springs Unit 1 generating plant
CUB	Citizens' Utility Board
Dth	Decatherm = 10 therms = 1,000 cubic feet of natural gas
DEQ	Oregon Department of Environmental Quality
EFSC	Energy Facility Siting Council
EITF	Emerging Issues Task Force of the Financial Accounting Standards Board
EPA	U.S. Environmental Protection Agency
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 hour
MMBtu	One million British thermal units
MW	Megawatts
MWa	Average megawatts
MWh	Megawatt hours
NERC	North American Electric Reliability Corporation
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 generating plant
REP	Residential Exchange Program
SB 408	Oregon Senate Bill 408
SEC	U.S. Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards (issued by the Financial Accounting Standards Board)
Trojan	Trojan Nuclear Plant
URP	Utility Reform Project
USDOE	U.S. Department of Energy
WECC	Western Electricity Coordinating Council

PART I

ITEM 1. BUSINESS.

General

Portland General Electric Company (PGE or the Company) 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. PGE's revenue requirements are determined based upon the forecast cost to serve retail customers, including an opportunity to earn a reasonable rate of return. PGE also participates in the wholesale market by purchasing and selling electricity and natural gas to utilities and energy marketers in order to balance its supply of power to meet the needs of retail customers and manage its net variable power costs (NVPC). 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 was incorporated in 1930 and is publicly-owned, with its common stock listed on the New York Stock Exchange under the ticker symbol "POR." The Company was a wholly-owned subsidiary of Enron Corp. (Enron) for the period from July 1, 1997 through April 3, 2006.

In 1997, Portland General Corporation, the former parent of PGE, merged with Enron, with Enron continuing in existence as the surviving corporation and PGE operating as a wholly-owned subsidiary of Enron. 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. 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 2008 its service area population was 1.6 million, comprising about 43% of the state's population. The Company added 6,409 retail customers during 2008, and as of December 31, 2008 served 810,197 retail customers.

As of December 31, 2008, PGE had 2,753 employees, with 888 employees covered under agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers (Local 125). Such agreements cover 854 and 34 employees for the five-year periods ending February 28, 2009 and August 1, 2011, respectively. PGE is in negotiations with Local 125 for a new agreement to replace the one scheduled to expire February 28, 2009. The existing agreement will remain in effect following the expiration date unless either party gives at least 60 days' written notice of termination.

<u>Available Information</u>

The Company's Annual Report 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 U.S. Securities and Exchange Commission (SEC). It is not intended that the Company'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 federal and state regulation, both of which can have a significant impact on the business and operations of the Company. In addition to those activities and agencies discussed below, the Company is subject to regulation by certain environmental agencies, as described in "Environmental Matters" in this Item 1.

Federal Regulation

PGE is subject to federal regulation by the Federal Energy Regulatory Commission (FERC) and by 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 as to accounting policies and practices, licensing of hydroelectric projects, transmission services, wholesale sales, issuance of short-term debt, and certain other matters. The Energy Policy Act of 2005 granted the FERC increased statutory authority to implement mandatory transmission and reliability standards, as well as enhanced oversight of power and transmission markets, including protection against market manipulation.

Wholesale - PGE has authority under its FERC tariff to charge market-based rates for wholesale energy sales made to other utilities and energy marketers. Under FERC Order 697, *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, re-authorization for continued use of market-based rates requires the filing of updated market studies on a regional schedule. PGE's current authorization is effective until June 2010, at which time the Company, as part of the western region, will file for re-authorization.

Transmission - Terms and conditions related to the transmission of electric energy are contained in PGE's Open Access Transmission Tariff (OATT), which is filed with the FERC. In 2007, the FERC issued Order 890, *Preventing Undue Discrimination and Preference in Transmission Services*, which includes requirements for greater specificity and transparency in the OATT and for enhanced coordination of transmission planning. PGE has submitted filings to incorporate into its OATT the requirements of the order. FERC Order 693, *Mandatory Reliability Standards for the Bulk-Power System*, issued in 2007, approved mandatory reliability standards developed by the North American Electric Reliability Corporation (NERC). Responsibility for compliance and enforcement of these standards has been given to the Western Electricity Coordinating Council (WECC), a regional electric reliability organization.

Pipeline - The Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978 provide FERC authority in matters related to 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 due to the Company's 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. Such requirements include an extensive public review process that involves numerous natural resource issues and environmental conditions. PGE holds FERC licenses for the Company's projects on the Deschutes and Willamette Rivers and is currently in the process of relicensing its four hydroelectric projects on the Clackamas River.

NRC Regulation

The NRC regulates the licensing and decommissioning of nuclear power plants. In 1993, the NRC issued a possession-only license amendment to PGE's operating license for the Trojan Nuclear Plant (Trojan), and in early 1996 approved the Trojan Decommissioning Plan, which has allowed PGE to proceed in decommissioning the plant. The NRC approved the completed transfer of spent nuclear fuel from the Trojan spent fuel pool to a separately licensed dry cask storage system that will house the nuclear fuel on the plant site until permanent storage is available. PGE completed the radiological decommissioning of the Trojan site in 2004 pursuant to an NRC-approved License Termination Plan, with the plant's Facility Operating License terminated by the NRC in 2005. Spent fuel storage activities will continue to be subject to NRC regulation until all nuclear fuel is removed from the site and the storage installation is fully decommissioned.

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. 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. Members of the EFSC are appointed 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 rate 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 interveners.

- *General Rate Cases*. PGE periodically evaluates the need to change its overall general 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, a proposed 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. For further information, see the Overview section of Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

- *Power Costs*. In addition to price changes resulting from the General Rate Case process, the OPUC has approved the following by which PGE can adjust retail customer prices to cover the Company's NVPC, consisting of direct and indirect costs of power and fuel less wholesale electricity sales.
    - Annual Power Cost Update Tariff. Under this tariff, customer prices are adjusted annually to reflect the latest forecast of NVPC for the following year. An initial 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 each calendar year.
    - 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 by application of an asymmetrical deadband within which PGE absorbs cost increases or decreases, with a 90/10 sharing of costs and benefits between customers and the Company outside of the deadband. Each year's results are subject to application of a regulated earnings test, with final determination of any customer refund or collection made by the OPUC through a public filing and review. For further information, see the Results of Operation section of Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

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.

Utility Rate Treatment of Income Taxes - In 2005, Oregon adopted Senate Bill 408 (SB 408). The law attempts to more closely match income tax amounts forecasted to be collected in revenues with the amount of income taxes paid to governmental entities by electric and natural gas investor-owned utilities or their consolidated group. The law requires that utilities file a report with the OPUC each year regarding the amount of taxes paid by the utility (with certain adjustments), as well as the amount of taxes authorized to be collected in rates, as defined by the statute. This report is filed by October 15th of the year following the reporting year. If the OPUC determines that the difference between the two amounts 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. The first adjustment under SB 408 applied to taxes paid to governmental entities and collected from customers on or after January 1, 2006.

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

For further information, see Note 6, Regulatory Assets and Liabilities, in the Notes to Consolidated Financial Statements.

Oregon Renewable Energy Act - Enacted in 2007 by the Oregon legislature, the Oregon Renewable Energy Act (the Act) established a Renewable Energy Standard which requires that utilities meet specified percentages of their Oregon retail load with electricity generated by renewable resources by certain dates. PGE and other large electricity providers are required to serve at least 5% of their retail load within the state from renewable resources from 2011 through 2014, 15% for 2015 through 2019, 20% for 2020 through 2024, and 25% in 2025 and subsequent years. PGE anticipates that it will meet the 2011 requirement of the Act with existing or currently planned renewable resources. Further, the Company expects that, with additional resources included in its current planning process, it will meet the 2015 requirement. It is anticipated that subsequent years' requirements will be met by the acquisition of additional renewable resources, as determined pursuant to the Company's integrated resource planning process. For further information, see Power and Fuel Supply in this Item 1.

The Act also provides for the recovery in customer rates of all prudently incurred costs required to comply with the Renewable Energy Standard. The OPUC has approved the establishment of a renewable adjustment clause mechanism (RAC), which became effective January 1, 2008. Under the RAC, PGE will submit a filing on April 1 of each year, with rates to become effective January 1 of the following year, to recover the revenue requirement of new renewable resources and associated transmission that are not yet reflected in general rates. As part of the RAC, the OPUC has authorized the deferral of eligible costs not yet included in rates until the next annual RAC filing.

Retail Customer Choice Program - Implemented in 2002 as part of Oregon's electricity restructuring law, the retail "customer choice" program allows the Company's commercial and industrial customers direct access to other suppliers of electricity (Electricity Service Suppliers, or ESSs). While "direct access" customers purchase their electricity from other suppliers, PGE continues to deliver the energy to these customers. The program provides for "transition adjustments" for customers that choose to purchase energy at market prices from investor-owned utilities or from ESSs. Such adjustments reflect the above-market or below-market cost of energy resources owned or purchased by the utility and are designed to ensure that such costs or benefits do not unfairly shift to the utility's remaining energy customers. The retail customer choice program has no material effect on the financial condition or results of operation of the Company. During 2008, ESSs supplied customers with a total average load of approximately 269 MWa, representing 20% of PGE's non-residential load and 12% of the Company's total retail load for the year. In early 2009, the three ESSs registered to transact business with PGE supplied a total of 28 customers, representing 214 accounts, with a total average load of approximately 222 MWa, representing 16% of the Company's non-residential load and 10% of total retail load.

Cost-of-service and market price options are also available to PGE's commercial and industrial customers. The Company offers an option by which certain large non-residential customers may, for a minimum three- or five-year term, elect to be removed from cost-of-service pricing, with energy supplied by an ESS or at a daily market rate by PGE. A total of 32 commercial and industrial customers, less than 1% of those eligible, were receiving service from PGE under market-based pricing options at the end of 2008.

Residential and small commercial customers can purchase electricity from PGE from a portfolio of rate options that include a basic cost-of-service rate, a time-of-use rate, and renewable resource rates. As of December 31, 2008, approximately 71,000 customers were enrolled in renewable energy options, with 2,100 enrolled in time-of-use options.

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. In 2008, approximately $47 million in such charges were billed to customers.

PGE also remits to the ETO amounts collected under a new Energy Efficiency Adjustment tariff to fund additional energy efficiency measures. The tariff, which became effective on June 1, 2008, includes an approximate 1% average price increase and is expected to provide about $14 million annually for measures that enable customers to reduce their energy use.

Regulatory Accounting

PGE is subject to the provisions of Statement of Financial Accounting Standards No. (SFAS) 71, *Accounting for the Effect of Certain Types of Regulation*, and currently applies its provisions to reflect the effects of rate regulation in its financial statements. The Company periodically assesses the applicability of the statement to its business, considering both the current and anticipated future rate environment and related accounting guidance. For further information, see "*Regulatory Assets and Liabilities*" in Note 2, Summary of Significant Accounting Policies, in the Notes to Consolidated Financial Statements.

Customers and Revenues

PGE conducts retail electric operations exclusively in Oregon within a state-approved service area. Competitors within the Company's service territory include the local natural gas company, which competes in the residential and commercial space heating, water heating, and appliance markets, and fuel oil suppliers, which compete primarily for residential space heating customers. In addition, commercial and industrial customers may choose to purchase their energy requirements from ESSs, in accordance with Oregon's electricity restructuring law.

The following table summarizes PGE's revenues for the years indicated, with certain averages for retail customers (excluding direct access customers) (dollars in millions, except as indicated):

	Years Ended December 31,					
	2008		2007		2006	
	Amount	%	Amount	%	Amount	%
Retail:						
Residential	$ 758	44%	$ 716	41%	$ 628	41%
Commercial	598	34	593	34	547	36
Industrial	158	9	159	9	206	14
Other	(6)	(1)	48	3	(14)	(1)
Total retail	1,508	86	1,516	87	1,367	90
Wholesale	195	11	201	12	135	9
Other	42	3	26	1	18	1
Total revenues	$ 1,745	100%	$ 1,743	100%	$ 1,520	100%
Average usage per customer (in kilowatt hours):						
Residential	11,080		10,953		10,944	
Commercial	72,486		74,303		75,709	
Industrial	11,392,166		11,449,959		15,736,138	
Average revenue per customer (in dollars):						
Residential	$ 1,066		$ 1,020		$ 907	
Commercial	5,996		6,050		5,664	
Industrial	730,994		730,791		916,897	
Average revenue per kilowatt hour (in cents):						
Residential	9.62¢		9.31¢		8.29¢	
Commercial	8.27		8.14		7.48	
Industrial	6.42		6.38		5.83	

For further information, see "Results of Operation" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

Retail

Residential customers comprised 88% of the Company's total customers as of December 31, 2008 and 2007, with the remainder consisting of commercial and industrial customers. Residential demand is sensitive to the effects of weather, with demand highest during the winter heating season, and the condition of the economy. Generally, a 1% increase in Oregon's unemployment rate results in an approximate 0.7% decrease in demand from the Company's residential customers.

Commercial and industrial customer classes are not dominated by any single industry. While the 20 largest customers constitute 6% of total retail revenues, they represent nine different commercial and industrial groups, including high technology, paper manufacturing, metal fabrication, health services, and governmental agencies. No single customer represents more than 5% of PGE's total retail load or 2% of total retail revenues. While demand by the Company's commercial and industrial customers is generally not affected by weather, these classes can be affected by employment. Generally, a 1% decrease in Oregon's employment rate results in an approximate 0.4% decrease in demand from the Company's commercial and industrial customers.

PGE's direct access customers consist of commercial and industrial customers who purchase their electricity from an ESS, with PGE delivering the electricity. The revenue earned in connection with the transmission and delivery of this electricity is included in Other retail revenue, net of transition adjustments. PGE served an average of 417 direct access customer accounts in 2008, 322 in 2007, and 239 in 2006.

Residential Exchange Program (REP) - In May 2007, the Bonneville Power Administration (BPA), which provides federal hydropower benefits under the REP, suspended payments under the program to investor-owned utilities, which meant that monthly payments in a total expected annual amount of $76.5 million to PGE were suspended. Because PGE passes REP payments along to its residential and small farm customers in the form of monthly billing credits, the suspension had no net income impact to the Company, but resulted in an approximate 14% average price increase to those customers.

In April 2008, the BPA partially restored benefits on a temporary basis. As a result, prices for residential and small farm customers were reduced by an average of 6.3%. The BPA provided $43 million in interim benefits to the Company, the majority of which was credited to customers by the end of 2008.

In September 2008, the BPA and PGE, as ordered by the OPUC, entered into an agreement, terminating on September 30, 2011, that will provide monthly payments totaling approximately $40 million over the 12-month period ending September 30, 2009. Such benefits will be credited to eligible customers. Remaining benefits under the agreement will be based upon certain power exchange rates and other amounts to be determined in BPA proceedings.

PGE will continue to pursue ongoing benefits for its customers. Various parties have challenged the agreements under which the BPA will provide the future benefits to the customers of investor-owned utilities, including PGE, and others who purchase electricity directly from the BPA.

Wholesale

PGE 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's wholesale market participation includes purchases and sales of power resulting from economic dispatch decisions for its own generation, which allows PGE to secure reasonably priced power for its customers, and purchases and sales of natural gas. 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, water conditions, and seasonal demand.

The majority of PGE's wholesale sales are to utilities and power marketers and are 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

Other includes sales of natural gas or oil in excess of generating plant requirements and revenues from transmission services, pole contact rentals, and certain other electric services to customers.

Seasonality

Demand for electricity by residential customers is affected by weather. Retail customer demand is typically highest in the winter across PGE's service territory when heating and lighting are heavily used. Customer demand also peaks in the summer months primarily due to the use of air conditioning. Within a given year, weather conditions are the dominant cause of usage variations from normal seasonal patterns for residential customers.

Heating degree-days is an indication of the likelihood that customers will use heating and cooling degree-days is an indication of the likelihood that customers will use air conditioning. Heating and cooling degree-days data is used to measure the effect of weather on the demand for electricity. A degree-day is measured by the difference between a base temperature of 65 degrees Fahrenheit and the average temperature for a given day. The following table indicates the heating and cooling degree-days for 2008, 2007 and 2006, along with 15-year averages provided by the National Weather Service, as measured at Portland International Airport:

	Heating	Cooling
2008	4,582	474
2007	4,374	400
2006	4,089	541
15-year average for 2008	4,169	467

PGE's all-time high net system load peak was 4,073 MW and occurred in December 1998. The Company's all-time "summer peak" was 3,743 MW, which was driven by unusually warm weather and increased air conditioning demand, and occurred in August 2008. For 2008, PGE's peak load was 4,031 MW, which occurred in December. PGE's average load was 2,623 MW for the winter and 2,324 MW for the summer in 2008, compared to 2,638 MW for winter and 2,271 MW for summer in 2007.

Power and Fuel Supply

Power Supply

PGE relies primarily upon its generating resources, as well as long- and short-term power purchase contracts, to meet its customers' energy requirements. The Company also continues to emphasize the expansion of renewable energy resources, as well as energy efficiency measures, to meet such needs and enhance customers' ability to manage their energy use more efficiently. The following table summarizes PGE's average resource capability (in MW) for the last three years:

	As of December 31,					
	2008		2007		2006	
	Capability	%	Capability	%	Capability	%
Generation	2,459	55%	2,449	53%	1,974	39%
Purchased power:						
Long-term contracts:						
Capacity/exchange	644		644		644	
Mid-Columbia hydro	545		566		567	
Confederated Tribes hydro	150		150		150	
Wind	35		35		35	
Other	243		243		426	
Total long-term contracts	1,617	36	1,638	36	1,822	36
Short-term contracts	379	9	485	11	1,226	25
Total purchased power	1,996	45	2,123	47	3,048	61
Total average resource capability	4,455	100%	4,572	100%	5,022	100%

That portion of PGE's energy requirements generated by its plants will vary 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, and the market price of electricity. For information regarding actual generating output and purchases for the period 2006-2008, see the Results of Operation section of Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

Generation

PGE's current generating portfolio consists of thermal, hydro, and wind resources. For a complete listing of these facilities, see Item 2. - "Properties."

Thermal PGE's coal and natural gas-fired generation facilities, with a total capability of 1,845 MW, together provided approximately 50% of the Company's total retail load requirement in 2008. These facilities continue to supply reliable power, with plant availability at approximately 89% during 2008.

Hydro The Company's FERC-licensed hydroelectric projects, with a total capability of 489 MW, provided 10% of the Company's total retail load requirement in 2008. 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.

Wind Biglow Canyon Wind Farm (Biglow Canyon), located in Sherman County, Oregon, is PGE's largest renewable energy project. Phase I of Biglow Canyon, comprised of 76 wind turbines with a total capacity of 125 MW, was completed and placed in service in December 2007. In 2008, Phase I provided approximately 2% of the Company's total retail load requirement. Construction of Phases II and III has begun with completion expected by the end of 2009 and 2010, respectively. When completed, Phases II and III will have a total of 141 wind turbines and a combined installed capacity of approximately 324 MW.

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, 2008, there were 23 projects that together provide approximately 48 MW of diesel-fired capacity at peak times.

Purchased Power

PGE supplements its own generation with long- and short-term wholesale contracts as needed to meet its retail load requirement and provide the most economic mix on a variable cost basis. Such contracts have terms ranging from one to 30 years and expire at varying dates through 2035. The following briefly describes the Company's major power purchase contracts:

Capacity/exchange - These contracts provide PGE with firm capacity to help meet the Company's peak loads. The contracts range from 30 MW to 300 MW and expire at various dates from 2009 through 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 545 MW of firm capacity. Under terms of its contract with one of the districts, the Company's share of the combined output of two of the projects is expected to decline from the current 233 MW to an estimated 158 MW in 2010 as the energy requirements of the district increase.

Confederated Tribes - PGE has a two-thirds ownership interest in the 450 MW Pelton/Round Butte hydroelectric project on the Deschutes River in central Oregon, 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. PGE has a long-term agreement that requires the Company to purchase, at market prices, the Tribes' interest in the output of the project during the term of the license.

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

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

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.

For further information regarding PGE's power purchase contracts, see Note 15, Commitments and Guarantees, in the Notes to Consolidated Financial Statements.

Solar - As part of its efforts to secure additional renewable energy resources, PGE has invested in two photovoltaic solar power projects through separate limited liability companies. The first project, with an installed capacity of approximately 104 kW, is located on property owned by the Oregon Department of Transportation. The second project, with a total installed capacity of approximately 1,095 kW, is located on the rooftops of three distribution warehouses in Portland. The projects were placed in service in December 2008 and January 2009. PGE serves as managing member for the limited liability companies, in which it has an initial interest of less than 1%, and operates both facilities under an agreement with the investor member.

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 operates Boardman and has a 65% ownership interest in the plant. The Company has a purchase agreement that provides coal for the plant through 2011. The coal is obtained from surface mining operations in Wyoming and is delivered by rail under two separate ten-year transportation contracts which extend through 2013.

Colstrip - PGE has a 20% ownership interest in Colstrip Units 3 and 4, located in southeastern Montana. Coal for the plants is obtained from an adjacent mine under a contract that extends to 2019, with available supplies sufficient to meet future requirements of the plant.

Natural Gas

Port Westward and Beaver - Firm gas supplies for Port Westward and Beaver are purchased up to 72 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 on an interruptible basis to the extent not utilized by the Company. PGE has access to 87,000 Dth/day of firm gas transportation capacity to serve the two plants and has also received authorization from the FERC to transport natural gas for others under a Part 284 blanket transportation certificate.

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. PGE believes that sufficient market supplies of gas are available to meet anticipated requirements of Port Westward and Beaver through 2010.

The Beaver generating plant has the capability to operate at full capacity on No. 2 diesel fuel oil when it is economic or if the plant's natural gas supply is interrupted. PGE had an approximate 6-day supply of oil at the plant site at December 31, 2008.

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. Firm gas supplies for Coyote Springs, based on anticipated operation of the plant, may be purchased up to 72 months in advance. PGE believes that sufficient market supplies of gas are available to fully meet requirements of Coyote Springs through 2010. Coyote Springs was designed to also operate on oil, although such capability has been deactivated in order to optimize natural gas operations.

Reliability

PGE's base of thermal, hydroelectric, and wind generating resources, along with wholesale power market products, currently provides the Company with the flexibility to respond to seasonal fluctuations in the demand for electricity from its retail and wholesale customers. PGE anticipates that generating capacity within the WECC, as well as an active wholesale market, will continue to provide sufficient supply to supplement the Company's generation and long-term power contracts. To meet anticipated future energy requirements and help assure continued system reliability, PGE utilizes an integrated resource planning process for acquisition of new supply. The process incorporates input from several sources and includes long-term projections of resource adequacy prepared by both PGE and the WECC.

Integrated Resource Plan

PGE's Integrated Resource Plan (IRP), required by the OPUC, describes the Company's energy supply strategy. 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, provide the best combination of expected cost and associated risks and uncertainties for PGE and its customers.

PGE filed an IRP with the OPUC in June 2007 covering the years 2008 through 2015. It proposed additional energy efficiency programs as well as renewable and demand-side resources. It also proposed power purchase agreements of varying terms and the acquisition of additional peaking capacity.

The OPUC did not officially acknowledge the Company's IRP, but found key elements of the plan to be reasonable and directed PGE to proceed with a Request for Proposal (RFP) for up to 218 MWa of new renewable resources. PGE issued the RFP in 2008 and developed a final short list of proposals in November, with negotiations expected to be completed in 2009. PGE began construction of Phases II and III of Biglow Canyon and proceeded with its proposed expansion of energy efficiency programs. Also during 2008, PGE began evaluating proposals received in response to an RFP issued for 50 MW of demand response measures, with agreements expected to be completed in 2009.

As requested by the OPUC, PGE has begun preparation of a new IRP that addresses resource requirements through 2020. PGE expects to file the updated IRP by late 2009.

Transmission and Distribution

PGE operates one balancing authority area in its service territory. A balancing authority area is an electric system bounded by interchange metering. PGE is responsible for continuously balancing electric supply to its customers with PGE's generated power and the power the Company purchases and sells with other entities so that generation internal to the balancing authority area, plus net imported power, matches customer loads. PGE also schedules deliveries of energy over its transmission system in accordance with FERC requirements.

Electric transmission systems deliver energy from electric generators to distribution systems for final delivery to customers. During the year ended December 31, 2008, PGE delivered approximately 21.4 million MWh to retail and wholesale customers 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 it is subject to the reliability rules of the WECC and the NERC. PGE's transmission system, together with contractual rights on other transmission systems, enables the Company to integrate and access generation resources to meet its customers' load requirements. PGE's generation is managed on a coordinated basis to obtain maximum load-carrying capability and efficiency. Portions of the Company's transmission and distribution systems are located:

- 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 Interior or lease by Native American tribes.

PGE's wholesale transmission services are regulated by the FERC pursuant to the Company's OATT, which is filed with the FERC and provides for market-based rates. In accordance with its OATT, PGE offers several transmission services to wholesale customers:

- Network integration transmission service, a guaranteed service that integrates generating resources to serve retail loads;
- Long- and short-term firm point-to-point transmission service, a guaranteed 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 an equal opportunity to access PGE's transmission system. PGE's transmission business is managed and operated independently from the power marketing business in accordance with the FERC's Standards of Conduct.

PGE is currently considering several generation interconnection projects (collectively referred to as the "Southern Crossing Project") under the Company's OATT. The Southern Crossing Project is being designed to integrate several of PGE's generation resources to include Boardman and Coyote Springs and other proposed wind and thermal generation projects. The addition of these generation resources necessitates the development of a significant, new, high-voltage transmission system across the Oregon Cascades to PGE's service territory. The Company is working closely with other utilities and the WECC to coordinate the Southern Crossing Project.

For additional information, see the Transmission and Distribution section of Item 2. - "Properties."

Environmental Matters

PGE operates in a state that is recognized for its environmental leadership and awareness. Accordingly, the Company's policy of environmental stewardship seeks to minimize risk and waste in its operations and promote the efficient use of energy.

PGE's operations are subject to a wide range of environmental protection laws, including those related to air and water quality, noise, waste disposal, endangered species, and climate change. The U.S. Environmental Protection Agency (EPA) and certain state agencies, including the Oregon Environmental Quality Commission (OEQC), the Oregon Department of Environmental Quality (DEQ), the Oregon Department of Energy, and the EFSC, have direct jurisdiction over environmental matters that include the siting and operation of generation and transmission facilities and the accumulation, cleanup, and disposal of toxic and hazardous substances. In addition, the Company's hydroelectric facilities are regulated and licensed by the FERC and are, in some cases, located on property under the jurisdiction of the U.S. Forest Service, which has authority over environmental protection in those cases.

Clean Air Standards

Clean Air Act - PGE's operations, principally its thermal generation plants, are subject to the federal Clean Air Act (CAA). Primary pollutants addressed by the CAA that affect PGE are sulfur dioxide (SO_2), nitrogen oxides, carbon monoxide, and particulate matter. State governments also monitor and administer certain portions of the CAA and must set standards that are at least equal to federal standards. Oregon's air quality standards currently equal or exceed federal standards.

PGE manages its air emissions by the use of low sulfur fuel, emission controls, emission 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 generation plants at forecasted capacity for at least the next several years within the limitations of current SO_2 emission requirements.

Clean Air Mercury Rule - The federal government adopted the Clean Air Mercury Rule in 2005 to regulate mercury air emissions from coal-fired generating plants. That rule was vacated by an appellate court decision in 2008; however, the states in which PGE facilities are located have adopted the following regulations concerning mercury emissions that could have an impact on the Company's Boardman and Colstrip plants:

- In October 2006, the Montana Board of Environmental Review adopted final rules on mercury emissions from coal-fired generating plants in Montana, including Colstrip, which require compliance with mercury emission limits by January 1, 2010.
- In December 2006, the OEQC adopted final rules on mercury emissions from coal-fired generating plants in Oregon, including Boardman, which require compliance with mercury limits by July 1, 2012. This deadline can be extended by one year under certain circumstances. The OEQC is considering revisions to the rule that would allow an extension of up to two years if needed due to extenuating circumstances beyond the Company's control.

Regional Haze - In accordance with federal regional haze rules aimed at visibility impairment in several federally protected areas, the DEQ conducted an assessment of emission sources that has indicated that the Boardman generating plant may cause or contribute to visibility impairment in several federally protected areas and would be subject to a Regional Haze Best Available Retrofit Technology (BART) Determination.

In December 2008, the DEQ issued a proposed plan that would require the installation of controls at Boardman in three phases. PGE estimates that the DEQ plan would cost between $575 million and $636 million (100% of total costs, excluding AFDC, in nominal dollars). PGE has no commitments in place at this time and cautions that the cost estimates are preliminary and subject to change.

The comment and public input period for the DEQ proposed plan has closed. PGE commented with an alternative BART/Reasonable Progress proposal that would allow for decision points along the DEQ timeline to provide flexibility to make the most responsible decision on future controls at those points. The OEQC is expected to adopt a rule in April 2009 now that the public process has been completed. The rule will be submitted to the EPA for approval as part of the Oregon Regional Haze State Implementation Plan (SIP). The Company expects the EPA to issue a decision on the SIP in early 2010.

Climate Change

Greenhouse gas emissions and their potential impacts on climate change have recently received increased public attention, with several legislative efforts initiated to establish mandatory control of greenhouse gas emissions. PGE is participating as a stakeholder in the Western Climate Initiative, a regional accord with a stated goal of reducing greenhouse gas emissions to 15% below 2005 levels by the year 2020. The DEQ, also a participant in the regional accord, has issued a notice of advanced rulemaking that would require reporting of greenhouse gas emissions for stationary sources. Any future laws that impose mandatory reductions in greenhouse gas emissions could have a material impact on PGE, as the Company relies on fossil fuels as a resource for power generation. PGE's Beaver, Coyote Springs, and Port Westward natural gas fired facilities and the Company's ownership shares of the Boardman and Colstrip coal plants provide nearly 75% of the Company's net generation capability.

Water Quality and Endangered Species 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. Significant changes thus far include modification in the timing of stored water releases, a spill program to assist juvenile fish at federal dams located in the Columbia River and Snake River basins, and continued investment in fish protection infrastructure (ladders and screens). These changes have resulted in occasional reductions in hydroelectric generation capability and the seasonal shifting of other generation from the fall and winter periods to the spring and summer periods. While PGE does not own facilities on these rivers, the Company does have contracts for power generated at 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 has an influence on the availability and prices of power in the regional wholesale market in which PGE participates to acquire adequate power to serve its retail customers.

PGE is implementing a series of fish protection measures at its hydro generation facilities on the Clackamas, Deschutes, and Willamette rivers that were prescribed by the U.S. Fish and Wildlife

Service and the National Marine Fisheries Service under their authority granted in the ESA and are contained in the Company's FERC operating licenses.

- ESA consultations on PGE's Clackamas River projects were completed in 2003 and will be in effect until a new license is granted by the FERC. A settlement agreement related to the license application for the Company's four hydroelectric projects on the Clackamas River was submitted to the FERC in March 2006 for review and approval, which is expected in 2010. Pending issuance of a new license, the project will operate under annual licenses issued by the FERC.
- As required under the 50-year license that the FERC issued to PGE in 2005 for its Pelton/ Round Butte project on the Deschutes River, PGE began construction of a selective water withdrawal system in late 2007 in an effort to restore fish passage on the upper portion of the river. The system will collect juvenile salmon and steelhead, allowing them to bypass the dam when migrating to the Pacific Ocean, and will regulate downstream water temperature. Completion of the system is expected in 2009.
- PGE's 30-year license for its Willamette River hydroelectric project, issued by the FERC in December 2005, required several fish protection measures that have since been implemented. Activity during 2008 involved evaluation of the performance of those measures, enhancements to the fish ladder, and removal of a retired building, as required under the FERC license.

In accordance with a 2002 agreement with state and federal agencies, environmental groups, and others, PGE is proceeding with decommissioning the Company's 22 MW Bull Run hydroelectric project, which included the Marmot and Little Sandy dams, located in the Sandy River basin. During 2008, the project ceased generation, as planned. Decommissioning and removal of project facilities continues in accordance with a FERC Surrender Order issued in 2004.

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 PGE facilities is subject to regulation under the federal Resource Conservation and Recovery Act. In addition, the use, disposal, and clean-up of polychlorinated biphenyls, contained in certain electrical equipment, is regulated by the federal Toxic Substances Control Act.

PGE is also subject to regulation under the Comprehensive Environmental Response Compensation and Liability Act (CERCLA), referred to as Superfund. CERCLA can assert joint and several liability for investigation and remediation costs for designated Superfund sites. PGE is currently listed by the EPA as a Potentially Responsible Party (PRP) at two Superfund sites discussed below.

Under the Nuclear Waste Policy Act of 1982, the U.S. Department of Energy (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 for Trojan. Trojan spent nuclear fuel 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 until the permanent off-site storage is available. No federal repository is expected to be available until 2020. Shipment of the spent nuclear fuel stored in the ISFSI to the off-site storage is not expected to be completed prior to 2033.

EPA Actions

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 the Portland Harbor on the federal National Priority List pursuant to CERCLA and listed sixty-nine PRPs, including PGE.

The Portland Harbor 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, PGE received a request from the EPA requiring the Company to provide information concerning its properties in or near the area being examined in the RI/FS, as well as several miles beyond that 5.7 mile segment. PGE requested, and the EPA has granted, an extension to August 2009 to respond. The boundaries of the site will be determined at the conclusion of the RI/FS in a Record of Decision, expected in 2010, in which the EPA will document its findings and select a preferred cleanup alternative.

Harbor Oil - In 2005, PGE received a Special Notice Letter for Remedial Investigation/Feasibility Study from the EPA, in which the Company was named as one of fourteen PRPs with respect to the Harbor Oil site, located in north Portland. The site includes the location of a company, Harbor Oil, Inc., that PGE utilized 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. The EPA has approved an RI/FS work plan for the site and on-site sampling commenced in 2008.

For further information on EPA actions, see “Environmental Matters” in Note 18, Contingencies, in the Notes to Consolidated Financial Statements.

ITEM 1A. RISK FACTORS.

Certain risks and uncertainties that may affect PGE’s business, financial condition, results of operation 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 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 operation.

The prices that the OPUC authorizes PGE to charge for its retail services are the major factor in determining the Company’s operating income, financial position, liquidity, and credit ratings. The OPUC has the authority to disallow recovery of any costs that it considers excessive or imprudently incurred. Furthermore, the regulatory process does not provide assurance that PGE will be able to achieve the earnings level authorized. In PGE’s most recent general rate case, the Company’s initial proposal included an overall rate increase of 8.9%, compared to a 7.3% overall increase approved by the OPUC. The Company will seek to manage costs at levels consistent with the reduced rate increase. However, if the Company is unable to do so, or if such cost management results in increased operational risk, the reduced rate increase could adversely affect the Company’s operations or results of operations. For further information, see the Overview section of Item 7. - “Management’s Discussion and Analysis of Financial Condition and Results of Operation.”

Currently, PGE utilizes a PCAM by which the Company can adjust future prices to reflect a portion of the difference between each year's forecasted and actual NVPC. Use of the approved cost sharing methodology 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 impact of forced generating plant outages, severe weather, reduced hydro availability, and volatile wholesale energy prices.

The current capital and credit market conditions may adversely affect the Company's access to capital, cost of capital, and ability to execute its business plan as scheduled.

Access to capital markets is important to PGE's ability to operate. The Company will face significant capital requirements for several large projects in the near term and expects to issue both debt and equity in 2009 in order to fund such projects. In addition, because of contractual commitments and regulatory requirements, the Company has limited ability to delay or terminate these projects, which include Biglow Canyon and the smart meter project. For further 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 Operation."

Recently, the general economic and capital market conditions in the United States and other parts of the world have deteriorated significantly and have adversely affected access to capital and increased the cost of capital. If these conditions continue or become worse, the Company's future cost of debt and equity capital and 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 as scheduled.

The current economic downturn has reduced the demand for electricity and has impaired the financial soundness of customers, which has adversely affected PGE's results of operation and could continue to do so. The economic downturn could also impair the financial soundness of the Company's vendors and service providers.

The slowing of the Oregon and national economies has resulted in reduced demand for electricity and could result in a continued reduction in such demand. This reduced demand has decreased the Company's earnings and cash flow and could continue to do so. In Oregon, the economic slow-down has included a sustained decline in the housing market and rising unemployment. Oregon's unemployment rate rose from an average of 5.2% for 2007 to an average of 6.3% for 2008, compared to the national average unemployment rate of 5.8%. Oregon's seasonally-adjusted unemployment rate increased to 9% in December 2008.

In addition, the Company's uncollectible customer accounts increased in the fourth quarter of 2008. If customers are not successful in generating sufficient revenue or are precluded from securing financing, they may not be able to pay, or may delay payment of, amounts owed to the Company. Any further inability of customers to pay the Company could adversely affect the Company's earnings and cash flow.

Furthermore, as a result of the current economic downturn affecting the economies of the state of Oregon, the United States and other parts of the world, the Company's vendors and service providers could experience serious cash flow problems. As a result, PGE's vendors and service providers may be unable to perform under existing contracts or may significantly increase their prices or reduce their output or performance on future contracts.

PGE faces regulatory and litigation risk with respect to recovery of the Company's investment in the closed Trojan Nuclear Plant.

There remains uncertainty regarding the ultimate outcome of legal and regulatory proceedings related to PGE's recovery of its investment in Trojan, which was closed in 1993. With respect to the OPUC proceedings, the Utility Reform Project (URP) and the class action plaintiffs have separately appealed, to the Oregon Court of Appeals, the September 30, 2008 OPUC order requiring PGE to refund $33.1 million to customers. With respect to the class actions, the Circuit Court has not yet ruled on the plaintiffs' motion to lift the abatement of the class action proceedings. The outcome of these proceedings could have a material adverse affect on PGE's results of operation and liquidity. For further information regarding Trojan legal and regulatory proceedings, see "Legal Matters" in Note 18, Contingencies, in the Notes to Consolidated Financial Statements and Item 3. - "Legal Proceedings."

Adverse market performance could result in further reductions in the fair market value of benefit plan trust assets and increase the Company's liabilities related to such plans. Such changes could result in a significant increase in funding requirements.

Performance of the capital markets affects the value of assets that are held in trust to satisfy future obligations under the Company's pension plan. Sustained adverse market performance, such as the losses in market value that reduced the value of the Company's pension plan trust assets in 2008, may 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.

Performance of the capital markets also affects the 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. A reduction in the value of these assets is recorded through current earnings and would adversely affect the funded status of the plans.

If PGE is unable to obtain sufficient financial returns on its benefit plan trust assets, the Company's operating results and cash flows could be negatively affected. For further information regarding PGE's contribution obligations under its pension and non-qualified benefit plans, see "Current Market Conditions - Valuation of Investments" in the Overview section of Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation", the "Contractual Obligations and Commercial Commitments" table in the Liquidity and Capital Resources section of Item 7, and "Pension and Other Postretirement Plans" in Note 10, Employee Benefits, in the Notes to Consolidated Financial Statements.

Wholesale energy markets are subject to forces that are often not predictable and which can result in price volatility, deterioration of liquidity, and general market disruption, adversely affecting PGE's costs and ability to manage its energy portfolio and procure required energy supply.

Wholesale electricity prices in the western United States are influenced primarily by factors related to supply and demand. These factors 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 wholesale energy markets can affect the availability and price of purchased power and demand for energy.

Changes in the creditworthiness of large wholesale counterparties can also affect PGE's variable power costs. Further, disruption in wholesale markets could result in a deterioration of market liquidity, increase the risk of counterparty default, affect the regulatory and legislative process in unpredictable ways, affect wholesale energy prices, and impair PGE's ability to manage its energy portfolio. Changes in wholesale energy prices can also affect the market value of derivative instruments and cash requirements to purchase electricity. Although the Company's PCAM can be expected to partially mitigate adverse financial effects related to wholesale market conditions, cost sharing features of the mechanism do not provide for full recovery in customer prices.

Fluctuations in the price of natural gas purchased as fuel for electricity generation can also impact the Company's liquidity. Recently, as a result of declining wholesale power and natural gas prices, PGE has been required to provide increased margin deposits pursuant to existing purchased power and natural gas agreements. If wholesale power and natural gas prices continue to decline, PGE could be required to continue to provide increased margin deposits, which could adversely affect the Company's liquidity.

Fluctuations in the price of natural gas purchased as fuel for electricity generation can also impact results of operations. PGE purchases natural gas in the open market or pursuant to short-term or variable-price contracts as part of its normal business operations. If market 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.

Under certain circumstances, one or more of the banks participating in PGE's credit facilities could decline to fund an advance requested by the Company or could withdraw from participation in the credit facility.

The Company has a $370 million multi-year revolving credit facility, of which $10 million expires in July 2012 and $360 million expires in July 2013, and a $125 million 364-day revolving credit facility, which expires in December 2009. Each facility is with a group of banks. These facilities supplement operating cash flow and provide a primary source of liquidity. The facilities are also used as backup for commercial paper borrowings and are available for general corporate purposes. The Company is required to make certain representations to the banks each time it requests an advance under one of the facilities.

These facilities are commitments on the part of the banks to make loans and, in the case of the multi-year revolving credit facility, to issue letters of credit. However, in the event of the occurrence of certain events that could result in a material adverse change in the business, financial condition or results of operation of PGE, the Company may not be able to make certain representations in which case the banks would not be required to lend. We are also subject to the risk that one or more of the participating banks may default on its 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 an advance, 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 facilities and in certain circumstances an acceleration of repayment of any outstanding advance.

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 ongoing capital projects, such as Biglow Canyon and the smart meter project. In their normal course of business, credit rating agencies re-examine 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 require the Company to pay higher interest rates on future long-term debt. In addition, access to the commercial paper market, a principal source of short-term financing, could be restricted, possibly resulting in higher interest costs. 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 (S&P). In January 2009, S&P revised its outlook on PGE from 'stable' to 'negative' and affirmed PGE's corporate credit rating. The outlook revision reflects the possibility that, in 2009, PGE's debt balances may increase and credit metrics may weaken to levels that would not be commensurate with S&P's expectations for the current 'BBB+' corporate rating. 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, which could have an adverse effect on the Company's liquidity.

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

Weather conditions can adversely affect PGE's revenues and costs and have an impact on the Company's financial and operating results. Temperatures outside the normal range 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.

Weather conditions that reduce stream flows could adversely affect PGE's hydro production and increase the Company's generation or power purchase costs required to meet the shortfall.

PGE derives a portion of its power supply from its hydroelectric facilities and from those owned by certain public utility districts in the state of Washington and the city of Portland, with whom the Company has long-term power 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. As indicated above, application of the Company's PCAM could help mitigate adverse financial effects of such shortfalls. However, full recovery is not assured and any inability to fully recover such costs in future rates could have a negative impact on the Company's results of operation.

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 replacement 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 and any inability to fully recover such costs in future rates could have a negative impact on the Company's results of operation.

Measures required to comply with state and federal regulations related to emissions from thermal electric generating plants could result in increased capital expenditures and changes to the Company's operations that could increase operating costs, reduce generating capacity and adversely affect PGE's results of operation.

Oregon and federal regulators are currently considering the air emission standards applicable to PGE's thermal generating plants in Oregon as part of separate regulatory processes related to haze, mercury, and the Company's air permits. Oregon regulators have adopted measures that will require installation of mercury controls at PGE's Boardman coal plant. Additional emissions controls could be required at Boardman, although specific measures will depend on the outcome of the regulators' reviews. For further 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 emission 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 further information, see Sierra Club et al. v. Portland General Electric Company in Item 3. - "Legal Proceedings."

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 existing 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. Cost and availability of natural gas and coal can also impact the cost and output of the Company's thermal generating plants.

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

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 generating facilities, or modifications to existing facilities, could be affected by various factors, including unanticipated delays and cost increases, which could result in the disallowance of certain costs in the rate determination process. In addition, the 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.

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

A portion of PGE's total energy requirement is comprised 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.

Legislative or regulatory efforts to reduce greenhouse gas emissions, in response to concerns related to climate change, could lead to increased capital and operating costs and have an adverse impact on the Company's operations or results of operation.

The outcome of legislative or regulatory efforts regarding greenhouse gas emissions, whether at the international, federal, regional, state, or local level, or the timing of any such laws or regulations that could be enacted, could have a material adverse effect on future results of operations and cash flows unless the additional costs incurred to comply with such laws or regulations can be recovered through regulated rates and/or future market prices for electricity. The cost of compliance with such measures could also make some of PGE's electric generating units uneconomical to operate or maintain. The Company would likely seek to recover through the ratemaking process any costs of additional emission control equipment or emission reduction measures, such as the cost of sequestration or purchasing allowances, or offset the cost of credits that may be required; however, there can be no assurance that such recovery would be granted.

PGE expects that future federal, and possibly state, legislation or regulation may result in the imposition of limitations on the Company's greenhouse gas emissions from fossil fuel-fired electric generating units. A number of bills have been introduced in the U.S. Congress that would require greenhouse gas emission reductions from fossil fuel-fired electric generation facilities and other sectors of the economy, although no such bill has yet been enacted. Compliance with these greenhouse gas emission reduction requirements could require PGE to make significant expenditures, including with respect to carbon capture and sequestration technology, purchase of emission allowances and/or offsets, fuel switching, and/or retirement of high-emitting generation facilities and replacement with lower emitting generation facilities.

The costs of compliance with these expected greenhouse gas requirements are subject to significant uncertainties, including with respect to the timing of the implementation of emission rules, required levels of emission reductions, emission allocation requirements, the maturation, regulation and commercialization of carbon capture and sequestration technology, and PGE's selected compliance alternatives. As a result, PGE cannot estimate the effect of any such legislation on its results of operations, financial condition or cash flows; however, the costs of compliance with such requirements could be material.

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 operation, 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 actions are subject to many uncertainties and management cannot predict the outcome of individual matters with assurance. The final resolution of some of the matters in which PGE is involved could require the Company to make additional expenditures, in excess of established reserves, 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 operation. 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 operation.

Certain pending legal and regulatory proceedings, such as the Trojan litigation, 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, may have an adverse effect on results of operations and cash flows for future reporting periods. For further information, see Note 18, Contingencies, in the Notes to Consolidated Financial Statements and Item 3. - "Legal Proceedings."

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

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.

To the extent reasonably possible, PGE utilizes insurance as a means to cost effectively mitigate the risk of physical loss or damage to the Company's property resulting from natural disasters, subject to certain coverage terms and conditions. The Company believes that the losses sustained to its transmission and distribution property relating to the December 2008 winter storm that affected Oregon will likely exhaust all remaining benefits available under the Company's transmission and distribution property insurance policy. As a result, PGE would be responsible for any damage sustained to its transmission and distribution property related to future storms, unless additional insurance is obtained. Related losses through the end of the term of the current insurance policy, which terminates in October 2009, would increase costs. The Company would likely seek recovery of any future uninsured storm-related losses through the ratemaking process; however, there can be no assurance that any recovery would be granted. If such recovery is not granted, these increased costs could have an adverse effect on PGE’s results of operation in a future period. Additionally, PGE may not be able to obtain subsequent insurance policies for its transmission and distribution property with similar terms and rates.

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

PGE is subject to regulation by the FERC and the OPUC, and by 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 the future course of changes in this regulatory environment or the ultimate effect that this changing regulatory environment will have on the Company’s business. However, changes in these 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.

Conditions that may be imposed in connection with the renewal of hydroelectric licenses could require large capital expenditures.

PGE is currently involved in renewing the federal license for its hydroelectric projects on the Clackamas River. The FERC, under the Federal Power Act, may impose conditions with respect to environmental, operating and other matters in connection with the renewal of PGE’s license. The Company cannot predict with certainty the requirements that might be imposed during the relicensing process, the economic impact of those requirements, whether a new license will ultimately be issued or whether PGE will be willing to meet the relicensing requirements to continue operating its Clackamas hydroelectric projects. The Company would likely seek recovery of any additional costs related to such licensing requirements through the ratemaking process.

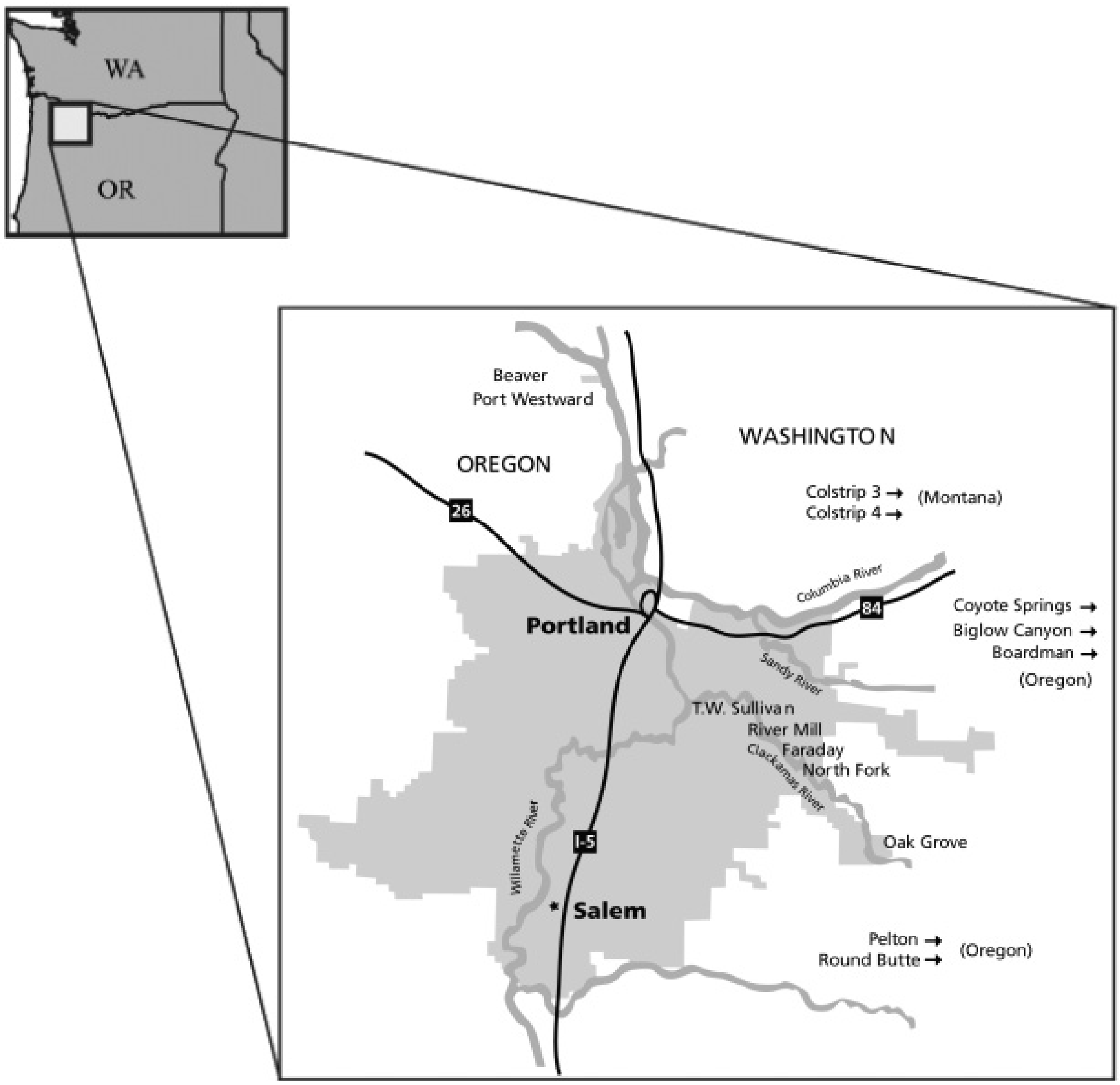
ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

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:



The following are generating facilities owned by PGE as of December 31, 2008:

Facility	Location	Capability [a]
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	529
Coyote Springs	Boardman, Oregon	233
Port Westward	Clatskanie, Oregon	413
Wind:		
Biglow Canyon	Sherman County, Oregon	125
Jointly-owned [b]:		
Coal:		
Boardman [c]	Boardman, Oregon	374
Colstrip 3 and 4 [d]	Colstrip, Montana	296
Hydro:		
Pelton [e]	Deschutes River	73
Round Butte [e]	Deschutes River	225
Total capability		2,459 MW

(a) Based on generation under normal operating conditions, net of station service used in the operation of a given facility.
(b) Reflects PGE's ownership share.
(c) PGE operates Boardman and has a 65% ownership interest.
(d) PPL Montana, LLC operates Colstrip 3 and 4 and PGE has a 20% ownership interest.
(e) PGE operates Pelton and Round Butte and has a 66.67% ownership interest.

Hydro Licensing

PGE holds FERC licenses under the Federal Power Act for its hydroelectric generating plants. The Company's Sullivan plant operates under a FERC license that expires in 2035, while the Pelton and Round Butte plants operate under a license that expires in 2055.

The Company filed an application with the FERC in 2004 to relicense the Clackamas River hydroelectric projects. A settlement agreement, resolving most of the issues raised in the relicensing proceeding and providing for a 45-year license term, was signed by the thirty-three participating parties in March 2006 and was submitted to the FERC for review and approval. The settlement agreement also provides for a collaborative process for the resolution of water temperature issues downstream of the project, which must be settled prior to the issuance of a new license. Pending approval of the new license, the project will operate under annual licenses issued by the FERC. It is expected that the FERC will issue a new license for the Clackamas River projects in 2010.

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, 2008, PGE owned an electric transmission and distribution system consisting of approximately:

Nominal Voltage Transmission and Distribution Lines	Circuit Miles
(in kilovolts)	
500	286
230	382
115	496
57	479
	1,643

In addition to the transmission and distribution lines presented in the table above, PGE has approximately 24,000 circuit miles of primary and secondary distribution lines that deliver electricity to its customers.

The Company also has an ownership in and other contractual rights associated with transmission lines that deliver electricity as follows:

- From the Colstrip plant in Montana to PGE;
- Contractual rights to approximately 18% 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
- Long-term contractual rights for 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 primarily used for the transmission of interstate purchases and sales of electricity among utilities, including PGE.

As of December 31, 2008, PGE owned 173 transmission and distribution substations throughout its service territory.

ITEM 3. LEGAL PROCEEDINGS.

<u>Citizens' Utility Board of Oregon v. Public Utility Commission of Oregon and Utility Reform Project and Colleen O'Neill v. Public Utility Commission of Oregon</u>, Public Utility Commission of Oregon 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 (Docket DR 10) 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 (Docket UE 88), 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 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 does 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 (1998 Remand).

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 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, after a full contested case hearing (Docket UM 989), 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. On November 7, 2003, the Marion County Circuit Court remanded the case to the OPUC to reduce rates or order refunds (2003 Remand). The opinion did not specify the amount or timeframe of any reductions or refunds. PGE and the OPUC each appealed the 2003 Remand to the Oregon Court of Appeals.

On October 10, 2007, the Oregon Court of Appeals issued an opinion that reversed the Settlement Order and remanded the Settlement Order to the OPUC for reconsideration. The Oregon Court of Appeals also vacated the 2003 Remand.

As a result of its reconsideration of the Settlement Order, on September 30, 2008, the OPUC issued an order that requires 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 order to the Oregon Court of Appeals.

On December 1, 2008, the OPUC issued an order that suspended the requirements imposed on PGE by the refund methodology outlined in the September 30, 2008 order for 60 days. On January 24, 2009, counsel for the URP and the Class Action Plaintiffs filed a motion with the Oregon Court of Appeals requesting a stay of the refund pending final disposition of their appeal. On February 2, 2009, the OPUC issued Order No. 09-039, which suspended the requirements imposed on PGE by the refund methodology, pending the Court of Appeals decision on the Motion for Stay filed by the URP and Class Action Plaintiffs. Based on the OPUC orders and request for stay, the timing of the refunds to customers is uncertain, but could occur during 2009.

Management cannot predict the ultimate outcome of the above matter. However, it believes that this matter 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 operation 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 charges 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.

At a status conference on October 15, 2008, the Circuit Court set a schedule for the filing of briefs on the plaintiffs' motion to lift the abatement. Oral argument occurred on January 12, 2009. A decision on the motion to lift the abatement is pending.

Management cannot predict the ultimate outcome of the above matter. However, it believes that this matter 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 operation 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. (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 have been filed with the court, with a decision now pending.

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 resolves the claims as 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 does 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 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 operation 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 January 15, 2008, plaintiffs sent PGE a sixty-day notice of intent to sue for alleged violations of the federal Clean Air Act (CAA), Oregon's State Implementation Plan (SIP) at PGE's Boardman Coal Plant, and the Plant's CAA Title V permit. On September 30, 2008, the plaintiffs sued PGE for these 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. The Company believes that it has strong defenses to the plaintiffs' claims and intends to vigorously defend against this lawsuit.

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 operation or cash flows.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

None.

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 20, 2009, there were 1,252 holders of record of PGE's common stock and the closing sales price of PGE's common stock on that date was $16.74 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
Fiscal 2008:			
Fourth Quarter	$ 24.55	$ 15.36	$ 0.245
Third Quarter	26.82	22.23	0.245
Second Quarter	24.92	22.44	0.245
First Quarter	27.70	21.89	0.235
Fiscal 2007:			
Fourth Quarter	28.83	25.74	0.235
Third Quarter	29.13	25.50	0.235
Second Quarter	31.25	26.40	0.235
First Quarter	30.16	25.56	0.225

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 operation and financial condition, future capital expenditures and investments, and applicable regulatory and contractual restrictions.

As required by Section 303A.12 of the NYSE Listed Company Manual, Peggy Y. Fowler, the Chief Executive Officer of the Company, certified to the NYSE on May 29, 2008 that she was not aware of any violation by the Company of the NYSE's corporate governance listing standards.

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 Operation" and Item 8. - "Financial Statements and Supplementary Data."

	Years Ended December 31,				
	2008	**2007**	**2006**	**2005**	**2004**
	(In millions, except per share amounts)				
Statement of Income Data:					
Revenues	$ 1,745	$ 1,743	$ 1,520	$ 1,446	$ 1,454
Income from operations	217	269	159	172	207
Net income	87	145	71	64	92
Earnings per share - basic and diluted	1.39	2.33	1.14	1.02	1.48
Dividends declared per common share	0.970	0.930	0.675	(a)	(a)
Statement of Cash Flows Data:					
Capital expenditures	383	455	371	255	194

	As of December 31,				
	2008	**2007**	**2006**	**2005**	**2004**
	(Dollars in millions)				
Balance Sheet Data:					
Total assets	$ 5,023	$ 4,108	$ 3,767	$ 3,638	$ 3,403
Total long-term debt (b)	1,306	1,313	1,003	890	922
Total shareholders' equity	1,354	1,316	1,224	1,197	1,279
Common equity ratio	47.3%	50.0%	53.0%	57.5%	58.4%

(a) Not meaningful as PGE was a wholly-owned subsidiary of Enron.

(b) For 2006 and earlier, includes preferred stock subject to mandatory redemption requirements.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION.

Information Regarding 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 relate to expectations, beliefs, plans, objectives for future operations, cash flows from operations, assumptions, business prospects, the outcome of litigation and regulatory proceedings, growth in demand for energy, future capital expenditures, market conditions, long-term earnings growth, the cost, completion and benefits of capital projects, future events, liquidity or performance, and other matters. Words or phrases such as "anticipates," "believes," "should," "estimates," "expects," "intends," "plans," "predicts," "projects," "will likely result," "will continue," 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, without limitation, management's examination of historical operating trends, 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 assets and facilities, operation and construction 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, without limitation, the proceedings related to the Trojan Investment Recovery, the Pacific Northwest Refund proceeding, the Portland Harbor investigation, and other matters described in Note 18, Contingencies, in the Notes to Consolidated Financial Statements in Item 8 of this Annual Report on Form 10-K;

- the continuing effects of the ongoing deterioration of the economies of the state of Oregon, the United States and other parts of the world, including reductions in demand for electricity, impaired financial soundness of vendors and service providers and elevated levels of uncollectible customer accounts;

- capital market conditions, including the recent credit crisis, interest rate volatility, severe 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;

- unseasonable or extreme weather and other natural phenomena, which, in addition to affecting PGE's customers' demand for power, could have a serious impact on PGE's ability and cost to procure adequate supplies of fuel or power to serve its customers, and could increase PGE's costs to maintain its generating facilities and transmission and distribution system;

- operational factors affecting PGE's power generation facilities, including forced outages, hydro conditions, wind conditions, and disruption of fuel supply;

- wholesale energy prices and their impact on the availability and price of wholesale power in the western United States;

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

- 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 emissions;

- the effectiveness of PGE's risk management policies and procedures and the creditworthiness of its 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 adversely affect PGE's results of operation;

- the outcome of efforts to relicense the Company's hydroelectric projects, as required by the FERC;

- 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, including the retirement of PGE's Chief Executive Officer and hiring of a new Chief Financial Officer;

- general political, economic, and financial market conditions;

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

- acts of war or terrorism;

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

- declines in the market prices for equity securities and increased funding requirements for defined benefit pension plans and other benefit plans.

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

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 are subject to fluctuations during the year due to the impacts of seasonal weather conditions on demand for electricity, price changes, customer usage patterns (which are affected by the condition of the local economy), and the availability and price of purchased power and fuel. PGE is a winter peaking utility that typically experiences its highest retail energy sales during the winter heating season, with a slightly lower peak in the summer that generally results from air conditioning demand.

General Rate Case Results - On January 23, 2009, the OPUC issued its final order concerning PGE's general rate case and proposed tariffs, which became effective on January 1, 2009. PGE's initial filing proposed an 8.9% average price increase related to higher purchased power and fuel costs, increased investment in utility plant, and higher operating expenses, compared to the 7.3% average price increase approved by the OPUC. The OPUC approved a cost of capital that provides for a capital structure of 50% equity and 50% debt and a return on equity of 10.1%. The order authorizes $121 million of increased revenues, consisting of approximately $95 million for NVPC and $26 million for other costs. Certain customer credits, including those related to 2007 results of the Company's PCAM, reduced the average price increase to approximately 5.6%. The OPUC also authorized PGE to file tariffs to implement a decoupling mechanism. For further information, see *Decoupling Mechanism* in "Legal, Regulatory and Environmental Matters" in this Item. Management is taking measures to manage costs in response to the final results of this general rate case.

Current Market Conditions - Volatile capital market conditions have adversely affected both access to capital and the cost of capital in global markets. PGE is continually assessing the impact of these market conditions on its operations, which include, but are not limited to, the following:

- *Impacts on the Company's plans to issue capital stock or debt* - PGE has estimated capital expenditure requirements of approximately $722 million in 2009 and $526 million in 2010 in addition to long-term debt maturities of $142 million in 2009 and $186 million in 2010. Although the current market conditions have made access to capital more difficult, PGE has recently been successful in securing a new credit facility and issuing long-term debt, which is discussed below in Capital and Financing. PGE believes it will be able to finance its ongoing capital projects in 2009 and anticipates issuing $675 million of debt in 2009 - 2010, of which $130 million was issued in January 2009, and approximately $175 million to $200 million of equity in 2009. In addition, the interest rate and interest period on $142 million of Pollution Control Bonds expire May 1, 2009, which will require PGE to remarket these bonds at current market rates or replace them with other debt instruments.

- *Valuation of Investments* -
    - PGE sponsors a pension plan. The fair market value of investments held by the pension trust decreased substantially in 2008. Pursuant to the Pension Protection Act of 2006, PGE is legally obligated to maintain a certain funding level with respect to the pension plan. The required funding level is determined annually based on certain actuarial assumptions and the valuation of the assets held by the pension trust. As of January 1, 2009, although PGE will not be required to fund a portion of the unfunded position of the pension plan in 2009, it will be required to in 2010, which is estimated to be $23 million. For future estimated contributions to the pension plan, see "Contractual Obligations and Commercial Commitments" in this Item 7.
    - Non-qualified benefit plan and nuclear decommissioning assets, which include marketable securities, are held in separate trusts to cover PGE's obligations under its non-qualified benefit plans and nuclear decommissioning activities, respectively. Fluctuations in the fair market value of the non-qualified benefit plan trust assets are recorded in current earnings. During 2008, the fair value of the trust assets decreased 33%, resulting in unrealized losses of $23 million, of which $17 million is included in Other income (expense), net in PGE's consolidated statement of income for the year ended December 31, 2008. Fluctuations in the fair market value of the nuclear decommissioning trust assets are recorded in Regulatory assets in the consolidated balance sheet. During 2008, the fair market value of the Nuclear decommissioning trust assets increased $1 million.

- *Other Demands on Liquidity* - Recently, PGE has been required to provide increased collateral to counterparties pursuant to existing purchased power and natural gas agreements. Such collateral consists of both cash, classified as Margin deposits on PGE's consolidated balance sheet, and letters of credit. These increased collateral requirements are primarily driven by decreases in the fair value of PGE's outstanding contracts. If wholesale power and natural gas prices continue to decline, PGE may be required to provide additional collateral. As of December 31, 2008, PGE had provided $308 million in collateral, consisting of $189 million in cash and $119 million in letters of credit, compared to $167 million as of September 30, 2008, consisting of $144 million in cash and $23 million in letters of credit, and $33 million as of December 31, 2007, consisting of $28 million in cash and $5 million in letters of credit.

For additional information with respect to these and other matters, see "Liquidity and Capital Resources" in this Item 7. and Item 7A. - "Quantitative and Qualitative Disclosures About Market Risk."

Customers - During 2008, PGE served an average of 811,315 retail customers compared to 800,587 during 2007, an increase of 1.3%. This customer growth, along with more extreme weather in 2008, resulted in a 1.9% increase in retail energy deliveries relative to 2007. On a weather adjusted basis, retail energy deliveries increased 0.8% from 2007.

The slow-down of the state's economy, including a sustained decline in the housing market, continued throughout 2008 and into 2009. Oregon's unemployment rate rose from an average of 5.2% for 2007 to an average of 6.3% for 2008, compared to the national average unemployment rate of 5.8%. Oregon's seasonally-adjusted unemployment rate increased to 9% in December 2008. PGE projects weather adjusted energy deliveries for 2009 will be comparable to weather adjusted energy deliveries for 2008, which is a result of the increase in the unemployment rate.

Installation of a limited number of new smart meters has begun as part of the smart meter project's acceptance testing phase, with full deployment expected to be completed by the end of 2010 for residential and commercial customers. PGE expects the project to provide improved services as well as operational efficiencies and cost savings. A new tariff, effective from June 1, 2008 through December 31, 2010, provides for recovery of costs related to this project, including the remaining net investment of the meters being removed, during this period.

Capital and Financing - PGE maintains liquidity through revolving credit facilities totaling $495 million and access to the commercial paper market. As of December 31, 2008, the unused available credit under the credit facilities is $166 million, with $228 million available as of February 20, 2009.

During 2008, PGE issued $50 million and repurchased $56 million of long-term debt, and in December PGE entered into a $125 million 364-day revolving credit facility. In January 2009, PGE issued $130 million of long-term debt.

PGE has major capital projects in process, which require financing in 2009 and 2010. PGE estimates that as of December 31, 2008, and after considering the issuance of $130 million of First Mortgage Bonds in January 2009, it could issue up to $598 million of additional First Mortgage Bonds under the most restrictive issuance test as delineated in the Mortgage and Deed of Trust securing the bonds.

In May 2008, PGE's Board of Directors approved a 4.3% increase in the Company's quarterly common stock dividend, from $0.235 per share to $0.245 per share. Dividends declared totaled $61 million in 2008, $58 million in 2007, and $42 million in 2006.

Power Supply - PGE utilizes its own generating resources and wholesale market purchases to meet the energy and capacity needs of its customers. In 2008, the Company's generating plants provided approximately 62% of its retail load requirement, compared to 56% in 2007 and 37% in 2006. The sequential increases are primarily due to the addition of Port Westward and Biglow Canyon Phase I to the Company's generation portfolio in June and December 2007, respectively. Generation from PGE's hydroelectric plants provided approximately 10% of its retail load requirement in each of the last three years (2006-2008). Current forecasts indicate below normal regional hydro conditions for 2009.

Biglow Canyon Phases II and III are currently under construction, with completion expected by the end of 2009 and 2010, respectively. The two phases will have a combined installed capacity of approximately 324 MW, further increasing the diversity of the Company's generating resource portfolio while minimizing related environmental impacts. For further information regarding estimated future capital expenditures, see "Capital Requirements" in "Liquidity and Capital Resources" in this Item 7.

As part of the Company's integrated resource planning process, PGE in 2008 issued a request for proposals for 218 MWa of new renewable energy resources and has identified a final short list of bidders, with agreements expected to be completed in 2009. Such resources, which are in addition to

Biglow Canyon, are required to become available between 2009 and 2014 to meet requirements of Oregon's Renewable Energy Standard.

PGE is currently preparing a new IRP to be filed by late 2009. PGE expects the new IRP to further define the Company's future energy and capacity needs and assess the economic viability of the proposed Boardman environmental retrofits.

Legal, Regulatory and Environmental Matters - On September 30, 2008, the OPUC issued an order in the matter of recovery of PGE's investment in Trojan. The order requires PGE to refund $33.1 million to customers who received service during the period October 1, 2000 through September 30, 2001. For further information, see Note 18, Contingencies, in the Notes to Consolidated Financial Statements.

In December 2008, the DEQ issued a proposed plan that would require the installation of emission controls at Boardman under a phased-in approach. For further discussion of this matter, see *Clean Air Standards*, in "Capital Requirements" under "Liquidity and Capital Resources" in this Item 7.

PGE is a party to other proceedings whose ultimate outcome could have a material impact on the results of operations and cash flows in future reporting periods. These include matters related to:

- Claims for refunds related to wholesale energy sales in the Pacific Northwest during 2000 - 2001;
- An audit and subsequent investigation by the FERC related to the Company's compliance with its OATT; and
- Investigations of the Portland Harbor and Harbor Oil sites.

For further information regarding the above and other matters, see Note 18, Contingencies, in the Notes to Consolidated Financial Statements.

The following price adjustments, as approved by the OPUC, became effective on January 1, 2009:

- An approximate 7.3% average price increase for final resolution of the general rate case, including projected NVPC. The approved NVPC projection establishes a new baseline for purposes of the PCAM calculation for 2009.
- A refund to customers of $16.7 million, before interest, for 2007 pursuant to the PCAM. This amount, plus accrued interest ($2.2 million as of December 31, 2008), will be refunded to customers over a one-year period beginning January 1, 2009.

The above items, combined with other miscellaneous tariff changes, result in an overall retail price increase of approximately 5.6% effective January 1, 2009.

Recent and pending rate actions include, but are not limited to, the following:

- Boardman Deferral Amortization - On October 9, 2007, PGE filed a request with the OPUC to amortize the deferral of $26.4 million of replacement power costs, plus accrued interest ($7.8 million as of December 31, 2008), associated with the forced outage of Boardman from November 18, 2005 through February 5, 2006. In its filing, the Company proposed that the amortization be offset with certain credits due to customers, with no price impact anticipated. PGE's request is subject to a regulatory proceeding that provides for both a prudency review with respect to the outage and to a regulated earnings test. Management cannot predict the ultimate outcome of this proceeding.

- Utility Rate Treatment of Income Taxes (SB 408) - PGE filed its report with the OPUC reflecting the amount of taxes paid by the Company for the 2007 reporting year, as well as the amount of taxes authorized to be collected in rates. The report is being reviewed as part of a formal process, with the OPUC expected to issue an order in April 2009. Pursuant to this report, PGE has determined that the appropriate collection due from customers is $14.7 million plus accrued interest, based on the OPUC's administrative rules that govern the calculation of the amount. Such amount is included in Regulatory assets as of December 31, 2008. Under OPUC rules, collections from customers will begin on June 1, 2009.

- Power Costs - Pursuant to the Annual Power Cost Update Tariff process, PGE annually files by April 1 a preliminary estimate of the following year's forecasted power costs. Under this process, new rates become effective January 1 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.

- Renewable Resources - Pursuant to a renewable adjustment clause mechanism (RAC), PGE can recover in customer prices prudently incurred costs of renewable resources that are expected to be placed in service in the current year. The Company will submit an annual filing to the OPUC by April 1, with rates to become effective January 1 of the following year. As part of the RAC, the OPUC has authorized the deferral of eligible costs not yet included in rates until the January 1 effective date of the new rates. Under this mechanism, PGE expects to file for recovery of its investments in Biglow Canyon Phase II and certain solar generating facilities in 2009.

- Selective Water Withdrawal System - Under a stipulation in PGE's general rate case proceeding, the Company removed from requested rates recovery of its investment in the Selective Water Withdrawal System at the Pelton/Round Butte generating facility. However, the stipulation also provided for a process to recover the cost of this system through a separate proceeding, which is currently in process. PGE anticipates rate recovery of this system when the project is completed, which is expected in the second quarter of 2009. PGE's initial filing in this matter indicated an annual revenue increase of $12.9 million related to this project.

- Decoupling Mechanism - Pursuant to authorization contained in the final order in PGE's general rate case, the Company on January 30, 2009 filed with the OPUC an application to defer, for later ratemaking treatment, potential revenues associated with a new decoupling mechanism as well as revenues associated with a return on equity (ROE) refund. The decoupling mechanism is intended to allow recovery of reduced earnings resulting from a reduction in sales of electricity resulting from customers' energy efficiency and conservation efforts. It would be implemented under a new two-year tariff that includes a Sales Normalization Adjustment (SNA), for residential and small non-residential customers, and a Nonresidential Lost Revenue Recovery (LRR), for large non-residential customers with loads less than 1 MWa. The SNA is based on the difference between actual, weather adjusted usage per customer and that projected in PGE's recent general rate case. The LRR is based on the difference between energy efficiency savings (as reported by the ETO) and those incorporated in the applicable load forecast. The ROE refund, estimated at approximately $1.9 million annually, would reduce PGE's allowed ROE from 10.1%, as approved by the OPUC, to 10.0%, and is intended to reflect a reduction in the Company's risk associated with the decoupling mechanism.

The American Recovery and Reinvestment Act of 2009 - On February 17, 2009, the American Recovery and Reinvestment Act of 2009 (the Act) was enacted. The Act provides for tax and appropriation benefits to the utility industry including the following:

- Extension of the renewable energy production tax credits (PTC) through 2012 for wind farms;
- Optional election of investment tax credits (ITC) in lieu of the PTC for wind farms placed in service through 2012. This ITC would provide a tax credit equal to 30% of qualified costs in the year the wind projects are placed in service. This is expected to include Biglow Canyon Phases II and III;
- Optional decision to receive, in lieu of PTC or ITC, Treasury Department energy grants equivalent to the ITC for (i) qualifying facilities placed in service in either 2009 or 2010 or (ii) qualifying facilities on which construction began in 2009 or 2010 and are placed in service after 2010 but before the credit termination date;
- Bonus depreciation of 50% for qualified property placed in service in 2009; and
- Appropriation opportunities providing funding for smart grid projects, vehicle electrification and research relating to potential carbon capture projects.

PGE is currently evaluating the impact of and alternatives under the Act.

Results of Operation

The following tables provide financial and operational information to be considered in conjunction with management's discussion and analysis of results of operation for 2008 compared to 2007, and for 2007 compared to 2006, which follow hereafter.

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

	Years Ended December 31,					
	2008		2007		2006	
	Amount	**As % of Rev**	**Amount**	**As % of Rev**	**Amount**	**As % of Rev**
Revenues, net	$ 1,745	100%	$ 1,743	100%	$ 1,520	100%
Operating expenses:						
Purchased power and fuel	878	50	879	50	763	50
Production and distribution	169	10	150	9	140	9
Administrative and other	190	11	184	11	164	11
Depreciation and amortization	208	12	181	10	219	15
Taxes other than income taxes	83	5	80	5	75	5
Total operating expenses	1,528	88	1,474	85	1,361	90
Income from operations	217	12	269	15	159	10
Other income (expense):						
Allowance for equity funds used during construction	9	1	16	1	16	1
Miscellaneous income (expense)	(14)	(1)	8	-	1	-
Other income (expense), net	(5)	-	24	1	17	1
Interest expense	90	5	74	4	69	4
Income before income taxes	122	7	219	12	107	7
Income taxes	35	2	74	4	36	2
Net income	$ 87	5%	$ 145	8%	$ 71	5%

Revenues, energy sold and delivered (based on MWh), and retail customers consist of the following for the periods presented (dollars in millions and MWh in thousands):

	Years Ended December 31,					
	2008		2007		2006	
	Amount	As % of Total	Amount	As % of Total	Amount	As % of Total
Revenues:						
Retail sales:						
Residential	$ 758	44%	$ 716	41%	$ 628	41%
Commercial	598	34	593	34	547	36
Industrial	158	9	159	9	206	14
Total retail sales	1,514	87	1,468	84	1,381	91
Other retail revenues	37	2	60	4	(2)	-
Trojan refund liability	(33)	(2)	-	-	-	-
Direct access customers	(10)	(1)	(12)	(1)	(12)	(1)
Total retail revenues	1,508	86	1,516	87	1,367	90
Wholesale revenues	195	11	201	12	135	9
Other operating revenues	42	3	26	1	18	1
Revenues, net	$ 1,745	100%	$ 1,743	100%	$ 1,520	100%
Energy sold and delivered (based on MWh):						
Retail energy sales:						
Residential	7,878	34%	7,688	32%	7,573	33%
Commercial	7,226	31	7,289	31	7,319	32
Industrial	2,472	11	2,485	11	3,541	16
Total retail energy sales	17,576	76	17,462	74	18,433	81
Delivery to direct access customers	2,418	10	2,165	9	999	4
Total retail energy deliveries	19,994	86	19,627	83	19,432	85
Wholesale sales	3,190	14	4,042	17	3,312	15
Total energy sold and delivered	23,184	100%	23,669	100%	22,744	100%
Average number of retail customers:						
Residential	710,991	88%	701,952	88%	691,931	88%
Commercial	99,690	12	98,096	12	96,674	12
Industrial	217	-	217	-	225	-
Direct access	417	-	322	-	239	-
Total	811,315	100%	800,587	100%	789,069	100%

PGE's total system load and retail load requirement for the periods presented are as follows (MWh in thousands):

	Years Ended December 31,					
	2008		2007		2006	
Generation:						
Thermal	9,454	43%	8,574	38%	5,207	22%
Hydro	1,822	8	1,801	8	2,002	9
Wind	384	2	28	-	-	-
Total generation	11,660	53	10,403	46	7,209	31
Purchased power:						
Term purchases	5,569		7,598		10,374	
Purchased hydro	3,037		3,300		3,208	
Spot purchases	1,648		1,379		2,229	
Total purchased power	10,254	47	12,277	54	15,811	69
Total system load	21,914	100%	22,680	100%	23,020	100%
Less: wholesale sales	(3,190)		(4,042)		(3,312)	
Retail load requirement	18,724		18,638		19,708	

Net income for the year ended December 31, 2008 was $87 million, or $1.39 per diluted share, compared to $145 million, or $2.33 per diluted share, for the year ended December 31, 2007. The decrease was due primarily to the following:

- A $20 million decrease resulting from an after-tax provision for a future refund to customers, related to the Trojan order;
- A $17 million decrease resulting from the impact of SB 408, with a $6 million customer refund (after taxes) recorded in 2008 and an $11 million collection (after taxes) recorded in 2007;
- A $16 million decrease from the after-tax impact of the deferral in 2007 of a portion of Boardman replacement power costs (including accrued interest) for potential future recovery (as approved by the OPUC); and
- A $15 million decrease from a decline in the fair market value of non-qualified benefit plan trust assets. While 2007 fair market value gains had a positive $3 million after-tax impact, losses in 2008 had a negative $12 million after-tax impact.

Partially offsetting the above decreases were:

- An approximate 2% increase in retail energy deliveries; and
- A $10 million increase related to application of the Company's PCAM -
    - In 2007, lower-than-projected NVPC resulted in a $16 million ($10 million after taxes) future refund to customers. PGE's NVPC as determined pursuant to the PCAM were less than the established baseline by $29.4 million, with 90% of the difference between this amount and the $11.7 million deadband threshold recorded for future customer refund; such refunds began on January 1, 2009.

- ○ In 2008, PGE's NVPC as determined pursuant to the PCAM were less than the established baseline by $31 million. No customer refund was recorded, however, as the Company's return on equity for the year did not attain the level required for a refund under the PCAM.

Net income for the year ended December 31, 2007 was $145 million, or $2.33 per diluted share, compared to $71 million, or $1.14 per diluted share, for the year ended December 31, 2006. The increase was due primarily to the following:

- A 1% increase in retail energy deliveries;
- Increased generation from the return of Boardman to full operation;
- The addition of Port Westward to the Company's base of generating resources;
- A $35 million increase resulting from the impact of SB 408, with an $11 million customer collection (after taxes) recorded in 2007 and a $24 million refund (after taxes) recorded in 2006;
- A $32 million increase resulting from the after-tax impact of incremental power costs (incurred in 2006) required to replace the output of Boardman during its extended repair outage; and
- A $16 million increase resulting from the after-tax impact of the 2007 deferral of a portion of Boardman replacement power costs for potential future recovery.

2008 Compared to 2007

Revenues in 2008 were comparable to 2007, with an increase of $2 million, which is the result of the following offsetting factors:

Total retail revenues decreased $8 million, or 1%, due primarily to the following offsetting factors:

- A $33 million decrease related to the accrual of refunds to customers pursuant to the OPUC order issued September 30, 2008 related to certain Trojan matters;
- A $28 million decrease related to SB 408, with an estimated refund to customers of $10 million recorded in 2008, resulting primarily from the Trojan order, compared to an estimated collection from customers of $18 million recorded in 2007;
- A $36 million increase resulting from a 2% increase in average price, which was driven by price increases for the Company's smart meter project and recovery of Biglow Canyon Phase I, partially offset by a price decrease for changes in forecasted 2008 power and fuel costs;
- A $10 million increase resulting from a 2% increase in total retail energy deliveries, due to more extreme weather conditions in 2008, as indicated in the table below, and a 1.3% increase in the average number of customers served in 2008 compared to 2007; and
- A $5 million increase in supplemental tariffs, which are fully offset in depreciation and amortization.

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		Cooling	
	2008	2007	2008	2007
1st Quarter	1,981	1,852	-	-
2nd Quarter	860	698	98	56
3rd Quarter	80	123	376	344
4th Quarter	1,661	1,701	-	-
Year-to-date	4,582	4,374	474	400
15-year average for the year-to-date	4,169	4,161	467	454

On a weather adjusted basis, retail energy deliveries increased 0.8% in 2008 compared to 2007, with deliveries to residential, commercial, and industrial customers increasing (decreasing) by 1.0%, (0.4)%, and 2.9%, respectively. PGE forecasts comparable total weather adjusted energy deliveries for 2009 relative to 2008.

Other retail revenues for 2008 and 2007 include $34 million and $42 million, respectively, in customer credits under the Residential Exchange Program administered by the BPA, with such amounts fully offset within Retail sales to residential and commercial customers. As a result of a decision by the Ninth Circuit, the BPA suspended such benefits in May 2007. In April 2008, benefits were temporarily restored under an Interim Relief agreement with the BPA. The resumption of customer credits, as approved by the OPUC, resulted in an average price reduction of approximately 6.3% for residential and small farm customers, effective April 15, 2008.

Wholesale revenues result from sales of electricity to utilities and power marketers which are made in conjunction with the Company's effort to secure reasonably priced power for its retail customers, manage risk and administer its current long-term wholesale contacts. Such sales can vary significantly period to period. Wholesale revenues in 2008 decreased $6 million, or 3%, from 2007 as a result of:

- A $42 million, or 21%, decrease in energy sales; partially offset by
- A $36 million, or 23%, increase in average sales price, related to higher natural gas prices and lower regional hydro availability.

Other operating revenues increased $16 million, or 62%, primarily due to sales of fuel oil of $15 million in 2008, which resulted in realized gains totaling $11 million. Pursuant to an assessment of reliability requirements, PGE reduced its oil inventory level at its Beaver generating plant.

Purchased power and fuel expense for 2008 decreased slightly from 2007. Decreases were related to the following:

- A $68 million reduction in the cost of purchased power, due primarily to a 16% decrease in purchases. The addition of Port Westward in June 2007 and Biglow Canyon Phase I in December 2007 to the Company's generating portfolio resulted in reduced reliance on purchases in the wholesale market. Further, reduced energy received from mid-Columbia hydro projects during 2008 was largely offset by increased Company-owned hydroelectric and wind production;

- A $41 million decrease related to settled natural gas swap agreements entered into in conjunction with PGE's management of its net power costs, due to increased natural gas prices. These agreements are among those financial instruments in the Company's diversified power supply portfolio used to manage market risk, with activities reflected in Wholesale revenues, Purchased power and fuel expense, and Other operating revenues. See "Commodity Price Risk" in Item 7A. - "Quantitative and Qualitative Disclosures About Market Risk" for further information; and
- A $15 million decrease in the estimated amount recorded for future refund to customers under the PCAM. In 2008, PGE's actual NVPC was less than the $13.8 million deadband threshold by approximately $17 million, resulting in a refund calculation comparable to that of 2007. However, based on the results of a regulated earnings test, no refund was recorded in 2008. Preliminary estimates indicate that the 2009 deadband will range from approximately $15 million below, to $30 million above, the baseline NVPC.

Offsetting the above decreases were:

- A $98 million increase in the cost of thermal production, due primarily to a 27% increase in gas-fired generation related to Port Westward;
- A $20 million increase related to the deferral of excess Boardman power costs in 2007, which were incurred in late 2005 and early 2006; and
- A $5 million increase due to a reduction in the Company's wholesale credit reserve in 2007, primarily as a result of a settlement with certain California parties involving transactions in 2000-2001.

The average variable power cost of PGE's total system load was $40.01 and $39.19 per MWh in 2008 and 2007, respectively, an increase of 2%. Averages exclude the effect of amounts related to regulatory power cost deferrals and wholesale credit provisions.

Current forecasts indicate that regional hydro conditions in 2009 will be below normal levels. 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. The following indicates the forecast of the April-to-September 2009 runoff (issued February 20, 2009) compared to the actual runoffs for 2008 and 2007 (as a percentage of normal):

Location	2009 Forecast	2008 Actual	2007 Actual
Columbia River at The Dalles, Oregon	79%	101%	97%
Mid-Columbia River at Grand Coulee, Washington	86	102	102
Clackamas River	84	163	100
Deschutes River	89	101	91

Production and distribution expense increased $19 million, or 13%, in 2008 due to the following factors:

- A $7 million increase in operating costs at the Company's generating facilities, including Port Westward and Biglow Canyon Phase I;

- A $4 million increase related to line maintenance, including locating expense related to the installation of fiber optic lines by other utilities and increased tree trimming;
- A $4 million increase resulting from an increase in the number of employees and general wage increases;
- A $3 million increase resulting from increased maintenance and repair expenses incurred at the Boardman and Beaver plants in connection with scheduled maintenance activities in 2008; and
- A $1 million increase related to the December 2008 snow and ice storm, net of expected insurance recovery in the amount of $7 million.

Administrative and other expense increased $6 million, or 3%, in 2008 due to the following factors:

- A $3 million increase associated with higher uncollectible retail customer accounts. In 2008, the provision for the allowance for uncollectible accounts increased $2 million, which was driven by the weakening of the economy, compared to a decrease of $1 million in 2007;
- A $2 million increase related to the settlement of a legal claim; and
- A $2 million increase in legal fees, including those related to the Company's 2009 general rate case proceedings and other regulatory matters.

Depreciation and amortization expense increased $27 million, or 15%, in 2008 due largely to the following offsetting factors:

- A $17 million increase related to capital plant additions, consisting primarily of $15 million related to Port Westward and Biglow Canyon Phase I;
- An $8 million increase related to accelerated depreciation of existing meters that are being replaced as part of the Company's smart meter project;
- A $5 million increase related to the amortization of regulatory liabilities during 2007 (fully offset by a corresponding increase in retail revenues); and
- A $3 million decrease in the amortization of computer software.

Taxes other than income taxes increased $3 million, or 4%, in 2008 due primarily to higher property taxes resulting from increases in assessed values, increased franchise fees resulting from higher retail revenues, and an increase in payroll taxes.

Other income (expense), net decreased $29 million, or 121%, in 2008 due primarily to the following factors:

- A $22 million decrease in income from non-qualified benefit plan trust assets resulting from a $17 million decline in the fair market value of the plan assets during 2008 compared to gains of $5 million in 2007; and
- A $7 million decrease in the allowance for equity funds used during construction, which resulted from lower construction work in progress balances during 2008 due to the completion of both Port Westward and Biglow Canyon Phase I in 2007.

Interest expense increased $16 million, or 22%, in 2008 primarily due to a higher level of outstanding long-term debt resulting from the issuance of additional First Mortgage Bonds during the second half of 2007 and into 2008. Long-term debt outstanding has increased as a result of funding the Company's capital projects. During 2008, the average outstanding balance of long-term debt was $1,310 million compared to $1,158 million for 2007, which resulted in an increase in interest expense of approximately $13 million. Additionally, the credit to interest expense for AFDC decreased $3 million as a result of lower construction work in progress balances during 2008 compared to 2007.

Income taxes decreased $39 million, or 53%, in 2008, with an effective tax rate of 28.4% in 2008 compared to 33.8% in 2007. These decreases are due primarily to lower taxable income and an increase of $9 million in federal and state energy tax credits generated from the operation of Biglow Canyon Phase I in 2008.

2007 Compared to 2006

Revenues in 2007 increased $223 million, or 15%, in 2007 from 2006 as a result of the following:

Total retail revenues increased $149 million, or 11%, in 2007 due primarily to the following offsetting factors:

- A $101 million increase resulting from a 7% increase in average price, which was driven by increases for higher power and fuel costs and cost recovery of Port Westward;
- A $76 million increase resulting from changes under the Residential Exchange Program due to the discontinuance of subscription power benefits (fully offset by increased purchased power costs) and suspension of cash payments in May 2007;
- A $58 million increase related to SB 408, with $18 million in collections recorded in 2007 and a $40 million refund recorded in 2006;
- A $78 million decrease resulting from a 5% reduction in total retail energy sales, which was driven by an increase in the number of customers served by ESSs; and
- A $13 million decrease in supplemental tariffs, which are fully offset in depreciation and amortization.

Lower energy sales to industrial customers resulted from a greater portion of industrial customers choosing direct access and purchasing their energy requirements from an ESS. Reduced revenues from these customers reflect the lower energy sales as well as an increase in “transition adjustment” credits, reflecting the difference between the cost and market value of PGE’s power supply portfolio, as provided by Oregon’s electricity restructuring law. The increase in the transition adjustment credits is due to both an increase in the number of customers served by ESSs and an increase in the rate of the transition adjustment credit.

On a weather adjusted basis, retail energy deliveries increased 1.1% in 2007, with deliveries to residential, commercial, and industrial customers increasing by 0.7%, 1.0%, and 2.2%, respectively, which was primarily driven by the increase in average customers served in 2007 discussed above.

Wholesale revenues in 2007 increased $66 million, or 49%, from 2006 as a result of:

- A $36 million, or 22%, increase in energy sales; and
- A $30 million, or 22%, increase in average sales price, related to higher natural gas prices and lower regional hydro availability.

Other operating revenues increased $8 million, or 44%, in 2007, primarily the result of increased gains from the sale of natural gas in excess of generating plant requirements.

Purchased power and fuel expense for 2007 increased $116 million, or 15%, from 2006. The average variable power cost of PGE's total system load was $39.19 and $33.65 per MWh in 2007 and 2006, respectively, an increase of 16%. Averages exclude the effect of amounts related to regulatory power cost deferrals, unrealized gains on derivative instruments, and wholesale credit provisions.

Increases in Purchased power and fuel expense were due primarily to the following:

- A $101 million increase related to higher thermal generation, which displaced higher-cost electricity purchases in the wholesale market. Increased generation was related primarily to operation of PGE's Port Westward plant during the last half of 2007 and full-year operation of Boardman, which was closed for repairs in the first half of 2006;
- A $95 million increase related to settled natural gas swap agreements entered into in conjunction with PGE's management of its net power costs;
- A $58 million increase related to a 12% increase in the average cost of purchased power;
- A $16 million estimate recorded for future refund to customers under the PCAM, based upon the difference between NVPC as determined pursuant to the PCAM and that forecasted and included in retail prices. PGE's 2007 NVPC under the PCAM was less than the established baseline by $29.4 million, with 90% of the difference between this amount and the $11.7 million deadband threshold recorded as a future refund;
- Unrealized gains on derivative activities of $5 million in 2006. Results of these activities were fully deferred in 2007 as a result of the OPUC's approval of the PCAM; and
- Discontinuance of subscription power benefits under the Residential Exchange Program (fully offset by increased revenues, with no net income effect).

Partially offsetting the above increases were:

- A $136 million decrease due to a 22% reduction in electricity purchases, related primarily to an increase in lower cost thermal generation;
- A $14 million decrease related to the deferral, for future recovery, of excess Boardman power costs, as approved by the OPUC in February 2007; and
- A $5 million decrease due to a reduction in the Company's wholesale credit reserve, related primarily to the settlement with certain California parties involving wholesale energy transactions in 2000-2001.

The addition of Port Westward in June 2007 and the full-year operation of Boardman combined to increase thermal production by 65% in 2007, resulting in reduced reliance on higher cost purchases in the wholesale market. Partially offsetting the increase in thermal production was a 10% decrease in Company-owned hydro production, resulting from lower stream flows.

Production and distribution expense increased $10 million, or 7%, in 2007 compared to 2006, due primarily to the following:

- A $6 million increase resulting from operating costs at Port Westward, which was placed in service in June 2007; and
- A $2 million increase related to maintenance activities at Boardman and Colstrip.

Administrative and other expense increased $20 million, or 12%, in 2007 compared to 2006, due to the following factors:

- A $9 million increase in incentive compensation primarily driven by higher net income and improved performance;

- A $6 million increase in employee benefits, primarily due to increased costs related to retirement plans; and
- A $2 million increase in stock-based compensation expense related to the Company's stock incentive plan.

Depreciation and amortization expense decreased $38 million, or 17%, from 2006 due primarily to the net effect of the following factors:

- A $27 million decrease resulting primarily from reductions in depreciation rates for utility plant assets and the authorized recovery of Trojan decommissioning costs, both of which became effective in January 2007 pursuant to the OPUC order in PGE's general rate case;
- A $13 million decrease in the amortization of regulatory assets (fully offset by a corresponding decrease in retail revenues);
- A $2 million decrease resulting from a reduction in the deferral of certain tax credits for future ratemaking treatment; and
- A $7 million increase related to Port Westward, Biglow Canyon Phase I, and other capital additions during 2007.

Taxes other than income taxes increased $5 million, or 7%, in 2007 primarily due to a $3 million increase in city franchise fees resulting from customer price increases during 2007 and a $2 million increase in property taxes resulting from higher assessed property values.

Other income (expense), net increased $7 million, or 41%, in 2007 due primarily to the net effect of the following factors:

- A $5 million increase in interest income related to the $26.4 million of excess power costs associated with Boardman's repair outage that was deferred for future recovery;
- A $5 million increase due the recognition of a loss provision on a non-utility assets and the write-off of certain software costs in 2006; and
- A $3 million decrease in income from non-qualified benefit plan trust assets.

Interest expense increased $5 million, or 7%, in 2007, primarily due to a higher level of outstanding long-term debt resulting from the issuance of additional First Mortgage Bonds in 2007. During 2007, the average outstanding balance of long-term debt was $1,158 million compared to $947 million for 2006.

Income taxes increased $38 million, or 106%, in 2007, with an effective tax rate of 33.8% in 2007 compared to 33.5% in 2006. These increases were due primarily to higher taxable income in 2007.

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 "The current capital and credit market conditions may adversely affect the Company's access to capital, cost of capital, and ability to execute its business plan as scheduled" in Item 1A. - "Risk Factors."

Capital Requirements

PGE has undertaken projects which will require significant capital spending in the next several years. The following table presents management's projected primary cash requirements for 2009 through 2013, as well as actual total capital expenditures for 2008 (in millions):

	Years Ending December 31,					
	2008	2009	2010	2011	2012	2013
Ongoing capital expenditures	$ 210	$ 224	$ 232	$ 210 - $230	$ 265 - $285	$ 240 - $260
Biglow Canyon Phase II	75	230	-	-	-	-
Biglow Canyon Phase III	22	176	201	-	-	-
Hydro licensing and construction	54	24	15	$50 - $70		
Smart meter project	10	66	53	-	-	-
Boardman emissions controls *	1	2	25	$255 - $295		
Total capital expenditures	$ 372	$ 722	$ 526			
Long-term debt maturities		$ 142	$ 186	$ -	$ 100	$ 100

* - Represents 80% of estimated total costs. For further explanation see "Boardman emissions controls" below.

Due to timing and cost uncertainties, estimated future expenditures related to the addition of up to 218 MWa of renewable energy sources and significant new high voltage transmission projects (including the Southern Crossing Project proposed by PGE) are not included in the table above. For further information, see Integrated Resource Plan in the "Power and Fuel Supply" section and the "Transmission and Distribution" section of Item 1. - "Business." 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 - Both Phases II and III are currently under construction. The estimated total cost of Phase II is $326 million, including $10 million of AFDC, and Phase III is $433 million, including $27 million of AFDC. Phases II and III are expected to be completed by the end of 2009 and 2010, respectively, with installed capacities of 149 MW and 175 MW, respectively.

Hydro licensing and construction - As required under the 50-year license that the FERC issued to PGE in 2005 for its Pelton/Round Butte project on the Deschutes River, PGE began construction of a selective water withdrawal system in late 2007 in an effort to restore fish passage on the upper portion of the river. The system will collect juvenile salmon and steelhead, allowing them to bypass the dam when migrating to the Pacific Ocean, and will regulate downstream water temperature. Completion of the system, at a total cost of approximately $105 million to $110 million, is expected in 2009. PGE's portion of the costs is expected to be approximately $80 million, including AFDC.

The Company filed an application with the FERC in 2004 to relicense the Clackamas River hydroelectric projects. A settlement agreement, resolving most of the issues raised in the licensing proceeding and providing for a 45-year license term, was signed by the thirty-three participating parties in March 2006 and was submitted to the FERC for review and approval. In June 2008, PGE filed an application with the DEQ proposing final resolution to the remaining lower Clackamas River temperature issues. Pending issuance of the new license, the project will operate under annual licenses issued by the FERC. It is expected that the DEQ will complete its water quality certification process in 2009 and the FERC will issue a new license for the Clackamas River projects in 2010.

Smart meter project - Pursuant to its smart meter project, PGE plans to install approximately 850,000 new customer meters that will enable two-way remote communication with the Company. Approximately 16,000 new meters are being installed as part of the project's systems acceptance testing phase, with the remaining meters to be installed starting in 2009 and continuing into 2010. PGE estimates the capital cost of the smart meter project to range from $130 million to $135 million. The project is expected to provide improved services, operational efficiencies, and a reduction in future operating expenses.

Boardman emissions controls - In accordance with federal regional haze rules aimed at visibility impairment in several federally protected areas, the DEQ conducted an assessment of emission sources that has indicated that the Boardman generating plant may cause or contribute to visibility impairment in several federally protected areas and would be subject to a Regional Haze Best Available Retrofit Technology (BART) Determination.

In December 2008, the DEQ issued a proposed plan that would require the installation of controls at Boardman in three phases. The first phase would require installation of controls for nitrogen oxides (NO_x) as required under the Clean Air Act, with estimated completion in 2011. The second phase would address mercury and sulfur dioxide removal using a semi-dry scrubber and bag house, with estimated completion in 2014. The DEQ proposes that these first two phases would meet federal requirements for installing BART. The third phase would require the installation of Selective Catalytic Reduction for additional NO_x control, with estimated completion in 2017. The DEQ proposes that the third phase would meet reasonable progress requirements towards haze emission reduction goals. PGE estimates that the DEQ proposed plan would cost between $575 million and $636 million (100% of total costs, excluding AFDC, in nominal dollars). PGE has no commitments in place at this time and cautions that the cost estimates are preliminary and subject to change.

The comment and public input period for the DEQ proposed plan has closed. PGE has commented with an alternative BART/Reasonable Progress proposal that would allow for decision points along the DEQ timeline to provide flexibility to make the most responsible decision on future controls at those points. The OEQC is expected to adopt a rule in April 2009 now that the public process has been completed. The rule will be submitted to the EPA for approval as part of the Oregon Regional Haze State Implementation Plan (SIP). The Company expects the EPA to issue a decision on the SIP in early 2010.

In 1985, PGE 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 a third party financial institution (Purchaser). This transaction reduced PGE's ownership interest in Boardman from 80% to 65%. The Purchaser leased the Boardman Assets to a lessee (Lessee) unrelated to PGE or the Purchaser. The term of the lease ends on December 31, 2013. Concurrently with the sale, PGE assigned to the Lessee certain agreements for the sale of power and transmission services from Boardman and the Intertie (P&T Agreements) to a regulated electric utility (Utility) unrelated to PGE, the Purchaser, or the Lessee. The payments by the Utility under the P&T Agreements generally cover the payment obligations of the Lessee under the lease, but do not cover all capital expenditures and are not expected to cover a material portion of the costs relating to the controls for the Boardman generating plant. The Purchaser has certain rights to participate in the financing of the portion of the total cost attributable to its interest. As a result of these agreements, PGE's share of the total cost for the emission controls on the Boardman generating plant is expected to be 80% if the Purchaser does not exercise its rights under the agreements to finance the portion of the total cost attributable to its interest. At the expiration of the lease, and in certain other circumstances, PGE has an option to repurchase the Boardman Assets.

As the regulatory requirements are clarified by the relevant agencies and the related costs more closely estimated, the Company will further evaluate the economic prudence of these expenditures. In doing so, the Company will also consider additional costs such as taxes, emission fees and other costs that may be imposed under any future laws related to climate change, as well as the Company's ability to recover these costs through the ratemaking process. Such additional costs, combined with any expenditures for controls, could constitute an investment in excess of what the plant can economically support. The ultimate impact that the above regulatory requirements and emission controls will have on future operations, costs, or generating capacity of the Company's thermal generating plants is not yet determinable and will be evaluated through the IRP process. PGE will seek recovery of its costs through the ratemaking process.

Liquidity

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

As of December 31, 2008, PGE had negative working capital of $279 million compared to working capital of $147 million as of December 31, 2007. This decrease in working capital is primarily driven by an increase in the net liabilities from price risk management activities of $350 million during 2008, which are classified as current in PGE's consolidated balance sheets. The regulatory asset related to price risk management is classified as noncurrent in PGE's consolidated balance sheets, impacting the Company's working capital. These derivative instruments are recorded at their estimated fair value ("mark-to-market"), as discussed in Note 4, Fair Value of Financial Instruments, in the Notes to Consolidated Financial Statements. During 2008, the commodities market experienced significant volatility which resulted in, among other things, decreased market prices for purchased power and natural gas in the second half of the year. Pursuant to regulatory accounting under SFAS 71, the mark-to-market of PGE's derivative instruments is deferred and, accordingly, the Company's net regulatory asset related to price risk management increased $350 million, with no impact to the statement of income.

PGE has an unsecured $370 million revolving credit facility (Credit Facility) with a group of banks that supplements operating cash flow and provides a primary source of liquidity. The Credit Facility is for general corporate purposes and the issuance of standby letters of credit, as well as for supporting the Company's commercial paper program, under which it may issue commercial paper for terms of up to 270 days. The commercial paper program requires the Company to maintain unused revolving credit capacity at least equal to the amount of commercial paper issued. In July 2012, $10 million of the Credit Facility matures, with the remaining $360 million maturing in July 2013.

In December 2008, PGE entered into an unsecured $125 million revolving credit facility (Short-term Credit Facility) with a separate group of banks on substantially the same terms as the Credit Facility discussed above, although no letters of credit may be issued under the Short-term Credit Facility. The Short-term Credit Facility, which matures in December 2009, is for general corporate purposes, including back-up for the issuance of commercial paper.

As of December 31, 2008, PGE had $65 million of commercial paper outstanding and borrowings of $131 million under the Credit Facility, the total of which is classified as Short-term debt on the consolidated balance sheet. The Company also had issued $133 million in letters of credit. As of February 20, 2009, PGE had $53 million of commercial paper outstanding and borrowings of $61 million under the Credit Facility and had issued $153 million in Letters of Credit. As of February 20, 2009, PGE had an aggregate of $228 million unused available credit under its credit facilities.

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

	Years Ended December 31,		
	2008	**2007**	**2006**
Cash and cash equivalents, beginning of year	$ 73	$ 12	$ 122
Net cash provided by (used in):			
Operating activities	183	344	106
Investing activities	(382)	(451)	(380)
Financing activities	136	168	164
Net change in cash and cash equivalents	(63)	61	(110)
Cash and cash equivalents, end of year	$ 10	$ 73	$ 12

Cash Flows from Operating Activities - The $161 million decrease in cash provided by operating activities in 2008 compared to 2007 was primarily attributable to the net effect of the following:

- A $184 million decrease related to higher margin deposit requirements with certain wholesale customers and brokers, driven primarily by lower power and natural gas prices, as discussed below;
- A $28 million decrease resulting from a 2007 cash settlement from the California Power Exchange, related to wholesale energy transactions in 2000-2001;
- A $15 million decrease as the result of higher interest payments in 2008, related to a higher level of outstanding long-term debt from the issuance of First Mortgage Bonds during the second half of 2007 and in 2008;
- A $7 million decrease resulting from higher employee incentive payments in 2008;
- A $7 million decrease resulting from payments for extended warranties related to Biglow Canyon Phases II and III in 2008;
- A $7 million decrease resulting from higher payments for payroll taxes and other employee benefits;
- A $6 million decrease resulting from higher payments under a long-term service agreement at Port Westward, which was placed in service in June 2007;
- A $6 million decrease due to the 2007 insurance recovery of costs related to a December 2006 wind storm;
- A $3 million decrease resulting from the payment of a legal settlement in 2008;
- A $55 million increase in cash received from retail sales of electricity, primarily driven by an increase in energy deliveries;

- A $34 million increase related to the Residential Exchange Program. Due to the suspension of monthly payments by the BPA during 2007 and the temporary lump sum benefit received in 2008 to be credited to customers, the cash received was $27 million higher in 2008 than in 2007. Because of lower annual benefits subsequent to the suspension, $7 million less was credited to customers in 2008;
- A $26 million increase due to reduced income tax payments in 2008, resulting from lower taxable income in 2008 and to tax credits related to the operation of Biglow Canyon Phase I; and
- A $6 million increase resulting from lower payments for reduced power and fuel purchases in 2008.

A significant portion of cash provided by operations consists of the recovery in customer prices of non-cash charges for depreciation and amortization. The $27 million increase in these charges in 2008 was due primarily to the authorized recovery of both Port Westward and Biglow Canyon Phase I, which were placed in service in June and December 2007, respectively, and accelerated depreciation of existing meters which are being replaced as part of PGE's smart meter project. The Company estimates that recovery of depreciation and amortization charges will be approximately $209 million in 2009. Combined with all other sources, cash provided by operations is estimated to be approximately $470 million for 2009, which reflects the return of approximately $120 million of margin deposits held by certain wholesale customers and brokers as of December 31, 2008. The estimated return of margin deposits is primarily based on the timing of contracts settling coupled with projected future energy prices. The remaining $141 million expected cash flows from operations in 2009 is based on normal operations, net of amount expected to be refunded to customers pursuant to the Trojan order.

Cash Flows from Investing Activities - Cash flows from investing activities consist primarily of new construction and improvements to PGE's distribution, transmission, and generation facilities. The $69 million decrease in cash used in investing activities was primarily attributable to the net effect of:

- A $74 million decrease in construction costs for Biglow Canyon;
- A $33 million decrease in construction costs for Port Westward, which was completed in June 2007;
- A $19 million increase in expenditures for the Pelton/Round Butte Selective Water Withdrawal System, construction of which began in late 2007;
- An $8 million increase in expenditures for the smart metering project;
- A $7 million increase in expenditures for solar generating facilities; and
- A $3 million increase resulting from the insurance recovery of 2006 storm damage costs.

The Company plans $722 million in total capital expenditures in 2009 related to Phases II and III of Biglow Canyon, hydro relicensing, ongoing capital expenditures related to upgrades to and replacement of transmission, distribution and generation infrastructure, and the smart meter project.

Cash Flows from Financing Activities - Financing activities provide supplemental cash for both day-to-day operations and capital requirements as needed. Cash flows from financing activities decreased $32 million in 2008 compared to 2007. During 2008, net cash provided by financing activities consisted of short-term borrowings 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 payments of dividends of $60 million. During 2007, net cash provided by financing activities primarily consisted of the issuance of long-term debt of $381 million, partially offset by net repayment of short-term debt of $81 million, the repayment of long-term debt of $71 million, and the payment of dividends of $58 million.

Dividends on Common Stock

The following table indicates common stock dividends declared in 2008:

Declaration Date	Record Date	Payment Date	Dividends Declared Per Common Share
February 20, 2008	March 25, 2008	April 15, 2008	$ 0.235
May 7, 2008	June 25, 2008	July 15, 2008	0.245
August 6, 2008	September 25, 2008	October 15, 2008	0.245
October 29, 2008	December 26, 2008	January 15, 2009	0.245

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 operation and financial condition, future capital expenditures and investments, and applicable regulatory and contractual restrictions.

On February 19, 2009, the Board of Directors declared a dividend of $0.245 per share of common stock to stockholders of record on March 25, 2009, payable on or before April 15, 2009.

Debt and Equity Financings

PGE has two unsecured revolving credit facilities with groups of banks which provide an aggregate maximum amount available to the Company of $495 million. The credit facilities are currently scheduled to terminate as follows: $125 million in December 2009, $10 million in July 2012 and $360 million in July 2013. These credit facilities supplement operating cash flow and provide a primary source of liquidity. As of December 31, 2008, PGE had $196 million outstanding under the credit facilities, consisting of borrowings and outstanding commercial paper, and had issued $133 million in letters of credit. PGE has approval from the FERC to issue short-term debt up to a total of $550 million through February 6, 2010.

In January 2009, PGE issued $130 million of First Mortgage Bonds in two series. One series is for $67 million to mature January 15, 2016 at a fixed rate of 6.80%. The second series is for $63 million to mature on January 15, 2014 at a fixed rate of 6.50%. As of December 31, 2008, total long-term debt outstanding was $1,306 million. As of February 20, 2009, the total long-term debt outstanding was $1,436 million, which includes the issuance of $130 million of First Mortgage Bonds in January 2009.

PGE's ability to secure sufficient long-term capital at a reasonable cost is determined by its financial performance and outlook, capital expenditure requirements, and alternatives available to investors. 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, as of February 25, 2009, the availability of the credit facilities, the expected ability to issue long-term debt and equity securities, and cash generated from operations would 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. The Company anticipates issuing a total of approximately $675 million of debt in 2009 - 2010, of which $130 million was issued in January 2009, and $175 million to $200 million of equity in 2009. In addition, the interest rate and interest period on $142 million of Pollution Control Bonds expire May 1, 2009, which will require PGE to remarket these bonds at current market rates or replace them with other debt instruments. PGE has approval from the OPUC to issue up to 12.5 million shares of common stock.

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 47.3% and 50.0% as of December 31, 2008 and 2007, respectively.

Credit Ratings and Debt Covenants

In January 2009, S&P affirmed its corporate investment grade credit rating and revised its outlook on PGE from 'stable' to 'negative.' The outlook revision reflects the possibility that in 2009 PGE's debt balances may increase and credit metrics may weaken to levels that would not be commensurate with expectations for the Company's current 'BBB+' corporate rating. In November 2008, Moody's revised its outlook on PGE from 'stable' to 'positive'. 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	Baa1	A
Senior unsecured debt	Baa2	BBB+
Commercial paper	Prime-2	A-2
Outlook	Positive	Negative

Should Moody's and/or S&P reduce their credit rating on PGE's unsecured debt to below investment grade, the Company could be subject to requests by certain of its wholesale, commodity and related transmission counterparties to post additional performance assurance collateral in connection with its price risk management activities. These deposits, which are classified as Margin deposits in PGE's consolidated balance sheet, are based on the contract terms and commodity prices and can vary from period to period. As of December 31, 2008, PGE had posted approximately $308 million of collateral with these counterparties, consisting of $189 million in cash and $119 million in letters of credit, $18 million of which is affiliated with master netting agreements. Based on the Company's energy portfolio, estimates of current energy market prices, and the level of collateral outstanding as of December 31, 2008, the approximate amount of additional collateral that could be requested upon a single agency downgrade to below investment grade is approximately $151 million and decreases to approximately $46 million by December 31, 2009. The amount of additional collateral that could be requested upon a dual agency downgrade to below investment grade is approximately $215 million and decreases to approximately $77 million by December 31, 2009.

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 Company's Amended and Restated Articles of Incorporation and the

Indenture of Mortgage and Deed of Trust securing the bonds. PGE estimates that as of December 31, 2008, and after considering the issuance of the $130 million of FMBs in January 2009, it could issue up to approximately $598 million of First Mortgage Bonds under the most restrictive issuance test in the Indenture of Mortgage and Deed of Trust. Any issuances would be subject to market conditions and amounts may 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 agreements, to 65% of total capitalization (debt ratio). As of December 31, 2008, the Company's debt ratio, as calculated under the credit agreements, was 52.7%.

Contractual Obligations and Commercial Commitments

The following indicates PGE's contractual obligations as of December 31, 2008 (in millions):

	Payments Due						
	2009	**2010**	**2011**	**2012**	**2013**	**Thereafter**	**Total**
Long-term debt	$ 142	$ 186	$ -	$ 100	$ 100	$ 778	$1,306
Short-term debt	203	-	-	-	-	-	203
Interest on long-term debt (1)	80	69	66	65	58	1,062	1,400
Capital expenditures	423	215	17	8	16	21	700
Purchased power and fuel:							
Electricity purchases	362	81	75	64	64	553	1,199
Capacity contracts	25	22	21	20	20	58	166
Public Utility Districts	8	7	7	5	5	39	71
Natural gas	69	38	31	15	14	38	205
Coal and transportation	19	13	11	3	3	-	49
Pension plan contributions (2)	-	23	26	35	28	-	112
Operating leases	7	7	7	8	8	212	249
Total	$1,338	$ 661	$ 261	$ 323	$ 316	$2,761	$5,660

(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, 2008.

(2) Contributions to the Company's pension plan are estimated based on numerous plan assumptions, including plan funded status. For plan year 2009, a discount rate of 6.91% was used and for the plan years of 2010 through 2014, a discount rate of 6.5% and return on plan assets of 9% was used. Contributions in 2014 are estimated to be $25 million. Contributions beyond 2014 have not been estimated.

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, Wanapum 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 project, 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 likely to have, a material current or future effect on its consolidated financial condition, revenues or expenses, results of operation, liquidity, capital expenditures or capital resources.

Critical Accounting Policies

The preparation of the 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 consolidated financial statements. The following accounting policies represent those that management believes are particularly important to the consolidated financial statements and that require the use of estimates, assumptions, and judgments to determine matters that are inherently uncertain.

Regulatory Accounting

As a regulated utility, PGE prepares its consolidated financial statements in accordance with the provisions of SFAS 71, *Accounting for the Effects of Certain Types of Regulation* (SFAS 71). The application of SFAS 71 results in differences in the timing and recognition of certain revenues and expenses in comparison with businesses in other industries.

PGE is subject to jurisdiction of the OPUC, which reviews and approves the Company's retail rates, ensuring that they provide the Company an opportunity to earn a fair return on its investment. The Company's rates, as authorized by the OPUC, are based on the cost of service and are designed to recover operating expenses and capital costs associated with generation, transmission and distribution assets used to provide regulated service to customers. Although changes in such rates are subject to a formal ratemaking process, it is expected that the OPUC will continue to recognize all prudently-incurred costs and authorize rates that allow for their recovery.

If future recovery of costs ceases to be probable, however, PGE would be required to write off its regulatory assets and liabilities. In addition, if PGE determines that all or a portion of its utility operations no longer meet the criteria for continued application of SFAS 71, the Company would be required to adopt the provisions of SFAS 101, *Revenue Recognition in Financial Statements*, which would require the Company to write off those regulatory assets and liabilities related to operations that no longer meet requirements of SFAS 71. Discontinued application of SFAS 71 could have a material impact on the Company's results of operation and financial position.

Asset Retirement Obligations

SFAS 143, *Accounting for Asset Retirement Obligations*, as interpreted by FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations-an interpretation of FASB Statement No. 143*, requires the recognition of asset retirement obligations (AROs), measured at estimated fair value, for legal obligations related to dismantlement and restoration costs associated with the retirement of tangible long-lived assets in the period in which the liability is incurred. 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. Capitalized asset retirement costs are depreciated over the life of the related asset, with accretion of the ARO liability classified as an operating expense on the statement of income. On the statement of income, AROs related to electric utility plant are included in depreciation and amortization expense, with those related to other property included in other income (expense). Accumulated asset retirement removal costs that do not qualify as AROs have been reclassified from accumulated depreciation to regulatory liabilities on the consolidated balance sheets.

Revenue Recognition

Retail revenue is billed monthly and is based on meter readings taken throughout the month. At the end of each reporting period, PGE estimates 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. Such amount is classified as Unbilled revenues in the Company's consolidated balance sheets. Unbilled revenues is calculated based on each month's actual net retail system load, the number of days from the meter read date through the last day of the month, and current retail customer prices.

Contingencies

The Company has unresolved legal and regulatory issues for which there is inherent uncertainty with respect to the ultimate outcome of the respective matter. Contingencies are evaluated based on SFAS 5, *Accounting for Contingencies*, using the best information available. In accordance with SFAS 5, 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. Reserves established reflect management's assessment of inherent risks, credit worthiness, and complexities involved in the collection process. No assurance can be given for the ultimate outcome of any particular contingency.

Price Risk Management

PGE engages in price risk management activities in its electric business, utilizing derivative instruments such as electricity forward, swap, and option contracts and natural gas forward, swap, option, and futures contracts to protect the Company against variability in expected future cash flows due to associated price risk and to minimize net power costs for retail customers. Derivative contracts are accounted for in accordance with SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended.

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 earnings 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 contracts 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 2008 pension expense by approximately $1.3 million. A 0.25% reduction in the discount rate would not have had a material effect on net periodic pension expense.

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 operation 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 Audit 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 units. 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.

Gains and losses from instruments that reduce commodity price risks are recognized when settled in purchased power and fuel expense, or in wholesale revenue. Valuation of these financial instruments reflects management's best estimates of market prices, including closing NYMEX and over-the-counter quotations, time value of money, and volatility factors underlying the commitments.

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 2008 were $4.8 million, $7.0 million, and $2.2 million, respectively, and in 2007 were $4.7 million, $7.6 million, and $1.6 million, respectively.

PGE's energy portfolio activities are subject to regulation, with related costs covered 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 under SFAS 71. As contracts are settled, these deferrals reverse. In PGE's value at risk methodology, no amounts are included for potential deferrals under SFAS 71.

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, 2008, a 10% change in the value of the Canadian dollar would result in an immaterial change in pre-tax income 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, 2008, PGE has $196 million of borrowings and outstanding commercial paper, classified as Short-term debt in the Company's consolidated balance sheet.

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

As of December 31, 2008, 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	2009	2010	2011	2012	2013	Thereafter
First Mortgage Bonds	$ 946	$ 970	$ -	$ -	$ -	$ 100	$ 100	$ 770
Pollution Control Revenue Bonds	184	189	142	37	-	-	-	10
7.875% unsecured notes	156	149	-	149	-	-	-	-
Total	$ 1,286	$ 1,308	$ 142	$ 186	$ -	$ 100	$ 100	$ 780

Interest rates on $142 million of Pollution Control Revenue Bonds are fixed until May 1, 2009. Pursuant to the terms of the bond agreements, PGE is required to redeem the entire principal amount of these bonds on or before May 1, 2009. The Company has the option to remarket the bonds and establish new terms concerning the interest rates, all subject to market conditions at the time of remarketing.

As of December 31, 2008, a 1% increase in the current interest rates would result in an approximate $1.4 million increase in annual interest expense.

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 electricity sales. Estimated provisions for uncollectible accounts receivable related to retail electricity sales are provided for such risk.

The following table presents PGE’s credit exposure for commodity activities and their subsequent maturity as of December 31, 2008. The table reflects credit risk included in accounts receivable and price risk management assets, offset by related accounts payable and price risk management liabilities (dollars in millions):

	Credit Risk Before Collateral	% of Total Exposure	Credit Collateral	Maturity of Credit Risk Exposure					
				2009	2010	2011	2012	2013	Thereafter
Externally rated:									
Investment grade	$ 36	99%	$ 15	$ (1)	$ 8	$ 8	$ 7	$ 6	$ 8
Non-investment grade	1	1	1	1	-	-	-	-	-
Total	$ 37	100%	$ 16	$ -	$ 8	$ 8	$ 7	$ 6	$ 8

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. Non-investment grade includes those counterparties with below investment grade credit ratings on senior unsecured debt. For non-rated counterparties, PGE performs credit analysis to determine an internal credit rating that approximates investment or non-investment grade. Included in this analysis is a review of counterparty financial statements, specific business environment, access to capital, and indicators from debt and capital markets. 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 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 2018. Management believes that circumstances that could result in the nonperformance by these counterparties are remote.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

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

Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying consolidated balance sheets of Portland General Electric Company and subsidiaries (the "Company") as of December 31, 2008 and 2007, and the related consolidated statements of income, shareholders' equity, comprehensive income, and cash flows for each of the three years in the period ended December 31, 2008. We also have audited the Company's internal control over financial reporting as of December 31, 2008, 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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, 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, 2008, 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, 2009

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

Years Ended December 31,	2008	2007	2006
Revenues, net	$ 1,745	$ 1,743	$ 1,520
Operating expenses:			
Purchased power and fuel	878	879	763
Production and distribution	169	150	140
Administrative and other	190	184	164
Depreciation and amortization	208	181	219
Taxes other than income taxes	83	80	75
Total operating expenses	1,528	1,474	1,361
Income from operations	217	269	159
Other income (expense):			
Allowance for equity funds used during construction	9	16	16
Miscellaneous income (expense)	(14)	8	1
Other income (expense), net	(5)	24	17
Interest expense	90	74	69
Income before income taxes	122	219	107
Income taxes	35	74	36
Net income	$ 87	$ 145	$ 71
Weighted-average shares outstanding (in thousands):			
Basic	62,544	62,512	62,501
Diluted	62,581	62,534	62,505
Earnings per share - basic and diluted	$ 1.39	$ 2.33	$ 1.14
Dividends declared per common share	$ 0.970	$ 0.930	$ 0.675

See accompanying notes to consolidated financial statements.

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

As of December 31,	2008	2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 10	$ 73
Accounts receivable, net	168	178
Unbilled revenues	96	92
Assets from price risk management activities	39	64
Inventories, at average cost:		
Materials and supplies	36	35
Fuel	35	29
Margin deposits	189	28
Current deferred income taxes	151	13
Other current assets	44	26
Total current assets	768	538
Electric utility plant:		
Production	1,943	1,944
Transmission	351	329
Distribution	2,307	2,184
General	259	252
Intangible	206	189
Construction work in progress	284	126
Total electric utility plant	5,350	5,024
Accumulated depreciation and amortization	(2,049)	(1,958)
Electric utility plant, net	3,301	3,066
Regulatory assets	825	304
Non-qualified benefit plan trust	46	69
Nuclear decommissioning trust	46	46
Other noncurrent assets	37	85
Total assets	$ 5,023	$ 4,108

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,	2008	2007
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 217	$ 227
Liabilities from price risk management activities	426	101
Short-term debt	203	-
Current portion of long-term debt	142	-
Other current liabilities	41	40
Accrued taxes	18	23
Total current liabilities	1,047	391
Long-term debt, net of current portion	1,164	1,313
Regulatory liabilities	683	574
Deferred income taxes	438	279
Unfunded status of pension and postretirement plans	174	40
Non-qualified benefit plan liabilities	91	86
Asset retirement obligations	58	91
Other noncurrent liabilities	14	18
Total liabilities	3,669	2,792
Commitments and contingencies (see notes)		
Shareholders' equity:		
Preferred stock, no par value, 30,000,000 shares authorized; none issued and outstanding as of December 31, 2008 and 2007	-	-
Common stock, no par value, 80,000,000 shares authorized; 62,575,257 and 62,529,787 shares issued and outstanding as of December 31, 2008 and 2007, respectively	659	646
Accumulated other comprehensive loss	(5)	(4)
Retained earnings	700	674
Total shareholders' equity	1,354	1,316
Total liabilities and shareholders' equity	$ 5,023	$ 4,108

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(Dollars in millions)

	Common Stock		Accumulated Other Comprehensive Loss	Retained Earnings	Total Shareholders' Equity
	Shares	Amount			
Balances as of December 31, 2005	62,500,000	$ 642	$ (3)	$ 558	$ 1,197
Vesting of restricted stock units	4,767	-	-	-	-
Stock-based compensation	-	1	-	-	1
Dividends declared	-	-	-	(42)	(42)
Net income	-	-	-	71	71
Other comprehensive income	-	-	1	-	1
Initial adoption of SFAS 158	-	-	(4)	-	(4)
Balances as of December 31, 2006	62,504,767	643	(6)	587	1,224
Vesting of restricted stock units	16,841	-	-	-	-
Shares issued pursuant to employee stock purchase plan	8,179	-	-	-	-
Stock-based compensation	-	3	-	-	3
Dividends declared	-	-	-	(58)	(58)
Net income	-	-	-	145	145
Other comprehensive income	-	-	2	-	2
Balances as of December 31, 2007	62,529,787	646	(4)	674	1,316
Vesting of restricted stock units	19,884	-	-	-	-
Shares issued pursuant to employee stock purchase plan	25,586	1	-	-	1
Former parent capital contribution	-	8	-	-	8
Stock-based compensation	-	4	-	-	4
Dividends declared	-	-	-	(61)	(61)
Net income	-	-	-	87	87
Other comprehensive income	-	-	(1)	-	(1)
Balances as of December 31, 2008	62,575,257	$ 659	$ (5)	$ 700	$ 1,354

See accompanying notes to consolidated financial statements.

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

Years Ended December 31,	**2008**	**2007**	**2006**
Net income	$ 87	$ 145	$ 71
Other comprehensive income (loss) items, net of taxes:			
Gains (losses) on cash flow hedges:			
Unrealized holding losses, net of taxes of $2 in 2007 and $16 in 2006	-	(2)	(26)
Reclassification to net income for contract settlements, net of taxes of $(1) in 2008, $(1) in 2007, and $7 in 2006	2	2	(11)
Reclassification of net realized and unrealized (gains) losses to SFAS 71 regulatory assets (liabilities), net of taxes of $1 in 2008, $(1) in 2007, and $(24) in 2006	(2)	-	37
Total gains on cash flow hedges	-	-	-
Pension and other postretirement plans' funded position, net of taxes of $69 in 2008 and $(12) in 2007	(108)	20	-
Reclassification of defined benefit pension plan and other benefits to SFAS 71 regulatory deferral, net of taxes of $(69) in 2008 and $12 in 2007	107	(18)	-
Minimum pension liability adjustment	-	-	1
Total other comprehensive income (loss) items, net of taxes	(1)	2	1
Comprehensive income	$ 86	$ 147	$ 72

See accompanying notes to consolidated financial statements.

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

Years Ended December 31,	2008	2007	2006
Cash flows from operating activities:			
Net income	$ 87	$ 145	$ 71
Reconciliation of net income to net cash provided by operating activities:			
Increase (decrease) in net liabilities from price risk management activities	350	(26)	132
Regulatory deferrals - price risk management activities	(350)	26	(132)
Depreciation and amortization	208	181	219
Trojan refund liability	34	-	-
Deferred income taxes	22	22	(38)
Unrealized (gains) losses on non-qualified benefit plan trust assets	17	(5)	(7)
Allowance for equity funds used during construction	(9)	(16)	(16)
Power cost deferrals, net	2	(9)	-
Senate Bill 408 deferrals, net of amortization	(1)	(16)	42
Other non-cash income and expenses, net	-	6	7
Changes in working capital:			
Net margin deposit activity	(163)	21	(94)
(Increase) decrease in receivables	6	(4)	17
Increase (decrease) in payables	(11)	19	(88)
Other working capital items, net	(8)	(2)	(11)
Other, net	(1)	2	4
Net cash provided by operating activities	183	344	106
Cash flows from investing activities:			
Capital expenditures	(383)	(455)	(371)
Sales of nuclear decommissioning trust securities	23	21	21
Purchases of nuclear decommissioning trust securities	(19)	(23)	(37)
Insurance proceeds	3	-	-
Other, net	(6)	6	7
Net cash used in investing activities	(382)	(451)	(380)
Cash flows from financing activities:			
Proceeds from issuance of long-term debt	50	381	275
Borrowings on revolving lines of credit	189	-	-
Payments on revolving lines of credit	(58)	-	-
(Payments) borrowings on short-term debt, net	72	(81)	81
Payments on long-term debt	(56)	(71)	(162)
Dividends paid	(60)	(58)	(28)
Debt issuance costs	(1)	(3)	(2)
Net cash provided by financing activities	136	168	164
Change in cash and cash equivalents	(63)	61	(110)
Cash and cash equivalents, beginning of year	73	12	122
Cash and cash equivalents, end of year	$ 10	$ 73	$ 12
Supplemental disclosures of cash flow information:			
Cash paid during the year for:			
Interest, net of amounts capitalized	$ 73	$ 58	$ 55
Income taxes	20	46	101
Non-cash investing and financing activities:			
Accrued capital additions	16	27	20
Accrued dividends payable	16	15	14
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, 2008, PGE served 810,197 retail customers with a service area population of approximately 1.6 million, comprising 43% of the state's population.

As of December 31, 2008, PGE had 2,753 employees, with 888 employees covered under agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers (Local 125). Such agreements cover 854 and 34 employees for five-year periods ending February 28, 2009 and August 1, 2011, respectively. PGE is in negotiations with Local 125 for a new agreement to replace the one scheduled to expire February 28, 2009. The existing agreement will remain in effect following the expiration date unless either party gives at least 60 days' written notice of termination.

PGE is subject to the jurisdiction of the Public Utility Commission of Oregon (OPUC) with respect to retail prices, services, accounting, issuance of securities and other matters. Currently, PGE is subject to cost-based ratemaking for its business. The Company is also subject to regulation by the FERC as to accounting policies and practices, wholesale and transmission prices and certain other operational matters, including those related to transmission planning, wholesale activities, reliability standards, and licensing of hydroelectric projects.

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, then the VIE is consolidated and a minority 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. See Note 16.

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 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 2007 and 2006 financial information to conform to the 2008 presentation. These reclassifications include (a) the presentation of income tax expense of $74 million and $36 million as one caption in the consolidated statements of income for the years ended December 31, 2007 and 2006, respectively, of which $71 million and $38 million was previously reported in operating expenses for the years ended December 31, 2007 and 2006, respectively, and ($3) million and $2 million was previously reported in Other income (deductions) for the years ended December 31, 2007 and 2006, respectively, and (b) the inclusion of long-term debt of $1,313 million in Total liabilities in the consolidated balance sheet as of December 31, 2007, which was previously reported in Total capitalization.

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, 2008 and $59 million as of December 31, 2007.

Accounts Receivable

Accounts receivable are recorded at invoiced amount and do not bear interest when recorded. A late fee of 1.5% may be assessed on residential account balances after 60 days and on commercial 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 electricity 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 derivative instruments such as forward, swap, and option contracts for electricity and natural gas, and futures contracts for natural gas. Pursuant to Statement of Financial Accounting Standards No. (SFAS) 133, *Accounting for Derivative Instruments and Hedging Activities (as amended)* (SFAS 133), derivative instruments are recorded on the consolidated balance sheets as assets or liabilities from price risk management activities measured at fair value, unless they qualify for the normal purchases and normal sales exception, with changes in fair value recognized in earnings unless hedge accounting applies.

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 under SFAS 133, as amended by SFAS 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities*. Other activities consist of certain electricity forwards that qualify as cash flow hedges of forecasted transactions, and electricity options, certain electricity forwards and swaps, certain natural gas forwards and swaps, and forward contracts for acquiring Canadian dollars. Such activities are utilized 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 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 regulation under SFAS 71, *Accounting for the Effects of Certain Types of Regulation* (SFAS 71).

Electricity sales and purchases from derivative activities that are physically settled are recorded in Revenues and Purchased power and fuel expense, 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 the requirements of Emerging Issues Task Force (EITF) Issue No. 03-11, *Reporting Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not "Held for Trading Purposes" as Defined in Issue 02-3* (EITF 03-11).

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 sheet and were $189 million and $28 million as of December 31, 2008 and 2007, 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 may include natural gas, oil, and coal and are valued at the lower of average cost or market.

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 are capitalized in accordance with American Institute of Certified Public Accountants Statement of Position 98-1, *Accounting for the Costs of Computer Software Developed or Obtained for Internal Use*. Costs of licensing the Company's hydroelectric projects are capitalized and amortized over the related license period.

PGE records AFDC, which represents the pre-tax cost of borrowed funds used for construction purposes and a reasonable rate 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 2008 and 2007, and 9% in 2006. AFDC from borrowed funds was $6 million in 2008, $10 million in 2007, and $8 million in 2006 and is reflected in the consolidated statements of income as a reduction to interest expense. AFDC from equity funds was $9 million in 2008 and $16 million in 2007 and 2006 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 3.7% in 2008, 3.9% in 2007, and 4.3% in 2006. Estimated asset retirement removal costs included in depreciation expense were $47 million, $43 million, and $68 million for the years ended December 31, 2008, 2007, and 2006, respectively.

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. The results of the most recent depreciation study, filed in November 2005, were incorporated into customer rates that became effective on January 17, 2007.

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	88 years
Wind	27 years
Transmission	48 years
Distribution	29 years
General	13 years

Distribution average life declined from 38 years in 2007 to 29 years in 2008 as a result of the shortened life for mechanical meters which are being retired over the period 2008 through 2010 as part of PGE's smart meter project. Full recovery of the undepreciated balance of the meters being retired was approved by the OPUC, effective June 1, 2008 through December 31, 2010.

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 pursuant to SFAS 143, *Accounting for Asset Retirement Obligations* (SFAS 143) 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. Amortization expense was $14 million in 2008 and $15 million in 2007 and 2006. Accumulated amortization was $109 million and $96 million as of December 31, 2008 and 2007, respectively.

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 in accordance with SFAS 115, *Accounting for Certain Investments in Debt and Equity Securities* (SFAS 115). 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, as PGE expects to recover costs for these activities through rates. 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 SFAS 71. Regulatory assets represent probable future revenue associated with certain costs that will be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenue associated with amounts that are to be credited to customers through the ratemaking process. Accounting under SFAS 71 is appropriate as long as rates are established by or subject to approval by independent third-party regulators; rates are designed to recover the specific enterprise's cost of service; and in view of demand for service, it is reasonable to assume that rates set at levels that will recover costs can be charged to and collected from customers.

Circumstances that could result in the discontinuance of SFAS 71 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 rates are set by regulators from cost-based regulation to another form of regulation. PGE periodically reviews the criteria of SFAS 71 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.

Power Cost Adjustment Mechanism

Since January 17, 2007, PGE has been 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 an 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 return on equity (ROE) for that year being no less than 1% above the Company's last authorized ROE. A collection will occur only to the extent that it results in PGE's actual ROE for that year being no greater than 1% below the Company's last authorized ROE. PGE's authorized ROE for 2008 was 10.1%. A final determination of any customer refund or collection is made by the OPUC through a public filing and review.

PGE estimates and records amounts related to the PCAM on a quarterly basis during the year. If the projected difference between baseline and actual NVPC for the year exceeds the 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 level required, a regulatory asset is recorded for any future amount due from retail customers.

For 2008, the deadband ranged from $14 million below, to $28 million above, the baseline. PGE's actual NVPC as determined under the PCAM for 2008 was less than the established baseline by approximately $31 million. As of December 31, 2008, no regulatory liability was recorded for this amount as PGE's earnings did not attain the level required under the PCAM's regulated earnings test. A final determination regarding the 2008 results will be made by the OPUC through a public filing and review in 2009.

Asset Retirement Obligations

AROs are accounted for in accordance with SFAS 143 and FIN 47, *Accounting for Conditional Asset Retirement Obligations* (FIN 47), which require, among other things, that the fair value of a liability for an ARO be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. PGE recognizes those legal obligations associated with the disposal of long-lived assets that result from the acquisition, construction, development or normal operation of such assets as AROs. 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 remaining life of the asset, which is included in Depreciation and amortization for electric utility plant and Other income (expense) for non-utility property in the consolidated statements of income.

Contingencies

Contingencies are evaluated based on SFAS 5, *Accounting for Contingencies*, 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 and the amount of the loss can be reasonably estimated. If a range of possible 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 the probable loss cannot be reasonably estimated. A material loss contingency will be disclosed when it is reasonably possible that an asset has been impaired or a liability incurred. Gain contingencies are recognized when realized and are disclosed when material. Legal costs incurred in connection with loss contingencies are expensed as incurred.

Accumulated Other Comprehensive Income (Loss)

SFAS 130, *Reporting Comprehensive Income*, establishes standards for the reporting of comprehensive income (loss) and its components. Accumulated other comprehensive income (loss) (AOCI) is comprised of the difference between the pension and other postretirement plans' obligations recognized in earnings to date, and the funded position as of December 31, 2008 and 2007.

Revenue Recognition

Revenues are recognized as electricity is delivered to customers and include amounts for any services provided. The rates 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 remitted to taxing authorities are included in Taxes other than income taxes and totaled $36 million in 2008, $35 million in 2007, and $32 million in 2006.

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 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 defers the recognition of certain revenues until the period in which the related costs are incurred or approved by the OPUC for amortization, in accordance with the provisions of SFAS 71. For further information, see *Regulatory Assets and Liabilities* in this Note 2.

Stock-Based Compensation

Stock-based compensation is accounted for in accordance with SFAS 123 (revised 2004), *Share-based Payments* (SFAS 123R), which requires the measurement and recognition of compensation expense for all share-based payment awards, including restricted stock units, based on the estimated fair value of the awards. Under SFAS 123R, 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 in accordance with SFAS 109, *Accounting for Income Taxes* (SFAS 109). This approach 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 in accordance with SFAS 109 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 rates and are charged or credited directly to a regulatory asset or regulatory liability. These amounts were recognized as net regulatory assets of $88 million and $87 million as of December 31, 2008 and 2007, respectively, and will be included in rates 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.

Uncertain tax positions are accounted for in accordance with FIN 48, *Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement 109* (FIN 48). An uncertain tax position represents 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 sustained by the taxing authorities, 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. As of December 31, 2008, PGE had no uncertain tax positions.

Interest and penalties related to any future income tax deficiencies will be recorded within Interest expense and Other income (expense), net, respectively, in the consolidated statements of income.

New Accounting Standards

Adopted Accounting Pronouncements

On January 1, 2008, PGE adopted Statement of Financial Accounting Standards No. (SFAS) 157, *Fair Value Measurements* (SFAS 157), which defines fair value, establishes criteria to be considered when measuring fair value and expands disclosures about fair value measurements. In February 2008, FASB Staff Position 157-2, *Effective Date of FASB Statement No. 157* (FSP FAS 157-2) was issued. FSP FAS 157-2 delays the adoption of SFAS 157 for nonfinancial assets and liabilities until fiscal years beginning after November 15, 2008, or January 1, 2009 for PGE. SFAS 157 does not modify any currently existing accounting pronouncements. PGE applies fair value measurements to certain assets and liabilities, including assets and liabilities from price risk management activities. The adoption of SFAS 157 did not have a material impact on the Company's consolidated financial position or consolidated results of operation. PGE expects that the adoption of FSP FAS 157-2 will not have a material impact on its consolidated financial position, consolidated results of operation, or consolidated cash flows. For additional information, see Note 4.

On September 30, 2008, PGE adopted FASB Staff Position No. SFAS 157-3, *Determining the Fair Value of a Financial Asset in a Market That Is Not Active* (FSP FAS 157-3), which clarifies the application of SFAS 157 in an inactive market and provides an illustrative example to demonstrate how the fair value of a financial asset is determined when the market for that financial asset is inactive. FSP FAS 157-3 was issued on October 10, 2008 and is effective upon issuance, including prior periods for which financial statements have not been issued. The adoption of FSP FAS 157-3 had no impact on the Company's consolidated financial position, consolidated results of operation, or consolidated cash flows.

On January 1, 2008, PGE adopted SFAS 159, *The Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115* (SFAS 159), which allows eligible financial assets and liabilities to be measured at fair value that are not otherwise measured at fair value. If the fair value option for an eligible item is elected, unrealized gains and losses for that item are reported in earnings at each reporting date. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparisons between the different measurement attributes the Company elects for similar types of assets and liabilities. The Company elected not to measure eligible financial assets and liabilities at fair value that were not otherwise measured at fair value. The adoption of SFAS 159 had no impact on PGE's consolidated financial position, consolidated results of operation, or consolidated cash flows.

On January 1, 2008, PGE adopted FASB Staff Position No. FIN 39-1, *Amendment of FASB Interpretation No. 39* (FSP FIN 39-1), which permits reporting entities to offset the receivable or payable recognized for derivative instruments that have been offset under a master netting arrangement. FSP FIN 39-1 requires financial statement disclosure of a reporting entity's accounting policy (to offset or not to offset), as well as amounts recognized for the right to reclaim cash collateral, or the obligation to return cash collateral, that have been offset against net derivative positions. PGE elected to continue to not offset its exposures under master netting arrangements in accordance with FSP FIN 39-1, and therefore elected not to offset any fair value amounts recognized for the right to claim cash collateral or the obligation to return cash collateral against its derivative positions. The adoption of FSP FIN 39-1 had no impact on PGE's consolidated financial position, consolidated results of operation, or consolidated cash flows.

On December 31, 2008, PGE adopted FASB Staff Position No. FAS 140-4 and FIN 46(R)-8, *Disclosures by Public Entities about Transfers of Financial Assets and Interests in Variable Interest Entities* (FSP FAS 140-4 and FIN 46R-8), which amends FIN 46R, *Consolidation of Variable Interest Entities (revised December 2003)-an interpretation of ARB. No 51* (FIN 46R), to require public entities, including sponsors that have a variable interest in a VIE, to provide additional disclosures about their involvement with VIEs to provide financial statements users with an understanding of: (1) significant judgments and assumptions made by an entity in determining whether it must consolidate a VIE and/or disclose information about its involvement with a VIE; (2) nature of restrictions on a consolidated VIE's assets reported by an entity in its statement of financial position, including the carrying amounts of such assets; (3) nature of, and changes in, the risks associated with an entity's involvement with a VIE; and (4) how an entity's involvement with a VIE affects the entity's financial position, financial performance, and cash flows. It also amends SFAS 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities-a replacement of FASB Statement No. 125*. The adoption of FSP FAS 140-4 and FIN 46R-8 did not have a material impact on PGE's consolidated financial position, consolidated results of operation, or consolidated cash flows.

On January 1, 2008, PGE adopted EITF Issue No. 06-11, *Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards* (EITF 06-11), which was ratified by the EITF at its June 27, 2007 meeting and clarifies how an entity should recognize the income tax benefit received on dividends that are (1) paid to employees holding equity-classified nonvested shares and (2) charged to retained earnings under SFAS 123R, *Share-Based Payment*. EITF 06-11 is applied prospectively to the income tax benefits that result from dividends on equity-classified employee share-based payment awards declared in fiscal years beginning after December 15, 2007, and interim periods within those fiscal years. The adoption of EITF 06-11 did not have a material impact on PGE's consolidated financial position, consolidated results of operation, or consolidated cash flows.

New Accounting Pronouncements

In December 2007, the FASB issued SFAS 160, *Noncontrolling Interests in Consolidated Financial Statements-an amendment of ARB No 51* (SFAS 160), and establishes accounting and reporting standards for the noncontrolling interest in a subsidiary, as well as the deconsolidation of a subsidiary. SFAS 160 clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the deconsolidated entity that should be reported as equity in the consolidated financial statements. It also (1) changes the way the consolidated income statement is presented by requiring consolidated net income to be reported at amounts that include the amounts attributable to both the parent and the noncontrolling interest, (2) establishes a single method of accounting for changes in a parent's ownership interest in a subsidiary that do not result in deconsolidation, and (3) changes the way the consolidated income statement is presented. SFAS 160 shall be applied prospectively, with the exception of the presentation and disclosure requirements, and is effective for fiscal years beginning on or after December 15, 2008, and interim periods within those fiscal years. Earlier application is not permitted. The presentation and disclosure requirements shall be applied retrospectively for all periods presented. Any noncontrolling interest resulting from the consolidation of less than wholly-owned subsidiary beginning January 1, 2009 will be accounted for in accordance with SFAS 160. PGE estimates that the adoption of SFAS 160 will not have a material impact on its consolidated financial position or consolidated results of operation, but will have an impact on the presentation of noncontrolling interests in its consolidated financial statements. Beginning with the Company's financial statements for the interim period ending March 31, 2009, any noncontrolling interest as of and for the period ending March 31, 2009 will be presented in PGE's consolidated financial statements as described above.

In March 2008, the FASB issued SFAS 161, *Disclosures about Derivative Instruments and Hedging Activities* (SFAS 161), which requires enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under SFAS 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. SFAS 161 is effective for annual and interim periods beginning after November 15, 2008, with early application encouraged. The adoption of SFAS 161 will not have an impact on PGE's consolidated financial position or consolidated results of operation.

In June 2008, FASB Staff Position No. EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities* (FSP EITF 03-6-1), was issued and addresses whether instruments granted in share-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the earnings allocation in computing earnings per share under the two-class method described in SFAS 128, *Earnings per Share*. FSP EITF 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those years. All prior period earnings per share data presented shall be adjusted retrospectively to conform to the provisions of the FASB Staff Position. Early application is not permitted. The adoption of FSP EITF 03-6-1 will not have a material impact on PGE's consolidated financial position or consolidated results of operation.

NOTE 3: BALANCE SHEET COMPONENTS

Accounts Receivable, Net

Accounts receivable is net of an allowance for uncollectible accounts of $4 million and $5 million as of December 31, 2008 and 2007, respectively. The following is the activity in the allowance for uncollectible accounts (in millions):

	Years Ended December 31,		
	2008	2007	2006
Balance as of beginning of year	$ 5	$ 45	$ 50
Increase (decrease) in provision	8	(34)	2
Amounts written off, less recoveries	(9)	(6)	(7)
Balance as of end of year	$ 4	$ 5	$ 45

Prior to January 1, 2006, PGE had established a reserve of $40 million related to pending legal matters between the Company and certain California parties related to wholesale energy transactions in the western markets from January 1, 2000 through June 20, 2001. In the first quarter of 2007, PGE reached a settlement that resolved these matters, resulting in the reversal of this reserve, which is reflected as a decrease in the provision for uncollectible accounts for the year ended December 31, 2007 in the table above.

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 former 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):

	Non-Qualified Benefit Plan Trust		Nuclear Decommissioning Trust	
	2008	2007	2008	2007
Cash equivalents	$ -	$ -	$ 27	$ 23
Marketable securities, at market value:				
Debt securities	3	11	19	23
Equity securities	23	36	-	-
Insurance contracts, at cash surrender value	20	22	-	-
Total	$ 46	$ 69	$ 46	$ 46

NOTE 4: FAIR VALUE OF FINANCIAL INSTRUMENTS

The fair value of cash and cash equivalents, accounts receivable, accounts payable, and short-term debt approximate their carrying amounts due to the short-term nature of these balances. Derivative instruments are recorded at their fair values, which are based on published market indices as adjusted for other market factors such as location pricing differences or internally developed models.

The carrying amounts of other investments are based on the underlying trust investments in marketable securities, which are recorded at fair value in accordance with SFAS 115 and are based on quoted market prices. These include the nuclear decommissioning trust and non-qualified benefit plan trust.

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, 2008, the estimated aggregate fair value of PGE's long-term debt was $1,286 million, compared to its $1,306 million carrying amount. As of December 31, 2007, the estimated aggregate fair value of PGE's long-term debt approximated its $1,313 million carrying amount.

Adoption of SFAS 157

Effective January 1, 2008, the Company adopted SFAS 157, which requires, among other things, enhanced disclosures about assets and liabilities carried at fair value on a recurring basis. Pursuant to FSP FAS 157-2, PGE will adopt SFAS 157 with respect to its nonfinancial assets and liabilities, which include asset retirement obligations, on January 1, 2009.

As defined in SFAS 157, fair value is 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, or exit price. However, as permitted under SFAS 157, PGE utilizes a mid-market pricing convention, the mid-point price between bid and ask prices, as a practical expedient for valuing the majority of its financial instruments.

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 SFAS 157 and includes in Level 3 all of those whose fair value is based on significant unobservable inputs.

The Company's financial assets and liabilities whose fair values were accounted for on a recurring basis are as follows by level within the fair value hierarchy (in millions):

	As of December 31, 2008			
	Level 1	**Level 2**	**Level 3**	**Total**
Assets:				
Nuclear decommissioning trust (1)	$ 27	$ 19	$ -	$ 46
Non-qualified benefit plan trust	26	-	-	26
Assets from price risk management activities (1)	-	33	6	39
	$ 53	$ 52	$ 6	$ 111
Liabilities - Liabilities from price risk management activities (1)	$ -	$ 297	$ 129	$ 426

(1) Activities are subject to regulation and, accordingly, gains and losses are deferred pursuant to SFAS 71 and included in regulatory assets or regulatory liabilities as appropriate.

As required by SFAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

Nuclear decommissioning trust assets reflect the assets held in trust to 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. These assets also include investments recorded at cash surrender value, which are excluded from the table above as they are not subject to SFAS 157. Assets and liabilities from price risk management represent derivative transactions entered into by PGE to manage its exposure to commodity price risk and minimize net power costs for service to the Company's retail customers and may consist of forward, swap, and option contracts for electricity and natural gas, and futures contracts for natural gas.

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 for the year ended December 31 (in millions):

	2008
Balance as of beginning of year	$ 1
Net realized and unrealized losses	(166)
Purchases and issuances, net	(12)
Net transfers out of Level 3	54
Balance as of end of year	$ (123)

Net realized and unrealized losses included in Purchased power and fuel expense in the consolidated statement of income, which includes $120 million in net unrealized losses, have been fully offset by the effects of regulatory accounting pursuant to SFAS 71.

NOTE 5: PRICE RISK MANAGEMENT

PGE 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. Such activities include power purchases and sales resulting from economic dispatch decisions for its own generation, which allows PGE to secure reasonably priced power for its customers. PGE utilizes derivative instruments, which may include forward, swap, and option contracts for electricity and natural gas, and futures contracts for natural gas, in its retail electric utility activities to manage its exposure to commodity price risk and to minimize net power costs for service to its retail customers.

PGE has elected to affirm its ongoing policy 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 pursuant to FIN 39, *Offsetting of Amounts Related to Certain Contracts*.

Changes in the fair value of retail derivative instruments prior to settlement that do not qualify for either the normal purchases and normal sales exception or for hedge accounting are recorded on a net basis in Purchased power and fuel expense. For derivative instruments that are physically settled, sales are recorded in Revenues, with purchases, natural gas swaps and futures recorded in Purchased power and fuel expense. PGE records the non-physical settlement of electricity derivative activities on a net basis in Purchased power and fuel expense, in accordance with EITF 03-11, as none of PGE's derivative activities are executed for trading purposes.

The following table reflects unrealized gains and losses recorded in net income from derivative activities (in millions):

	Years Ended December 31,		
	2008	**2007**	**2006**
Unrealized gains (losses)	$ (351)	$ 26	$ (127)
SFAS 71 regulatory asset (liability)	351	(26)	132
Net unrealized gains	$ -	$ -	$ 5

During 2008, the commodities market experienced significant volatility which resulted in, among other things, decreased market prices for purchased power and natural gas. This resulted in unrealized losses of $351 million in 2008, all of which are deferred pursuant to SFAS 71 until the underlying contract is settled. For a discussion of how fair value is determined for these derivative instruments, see Note 4.

The following table reflects derivative activities from cash flow hedges recorded in comprehensive income, before taxes (in millions):

	Years Ended December 31,		
	2008	2007	2006
Unrealized holding losses	$ -	$ (4)	$ (42)
Reclassification to net income for contract settlements	3	3	(18)
Reclassification of net realized and unrealized (gains) losses to SFAS 71 regulatory assets (liabilities)	(3)	1	61
Net unrealized gains on cash flow hedges recorded in OCI	$ -	$ -	$ 1

Hedge ineffectiveness from cash flow hedges was not material in 2007, and 2006. Additionally, during 2007, PGE elected to discontinue hedge accounting for the Company's remaining outstanding derivatives designated as cash flow hedges, in accordance with SFAS 133, which did not have a material impact on the Company's consolidated financial position or consolidated results of operation. As of December 31, 2008, net unrealized gains of $1 million, substantially all of which the Company estimates will be reclassified into earnings within the next twelve months, are fully offset by SFAS 71 regulatory accounting, with the balance to settle over the next 33 months. These unrealized gains, fully offset by SFAS 71 regulatory accounting, are included in Accumulated other comprehensive loss in the consolidated balance sheet as of December 31, 2008.

NOTE 6: REGULATORY ASSETS AND LIABILITIES

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

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

	Weighted Average Remaining Life	December 31, 2008	December 31, 2007
Regulatory assets:			
Price risk management	1 year	$ 387	$ 37
Pension and other postretirement plans	(1)	232	57
Deferred income taxes	(2)	88	87
Boardman power cost deferral	(3)	34	31
Debt reacquisition costs	25 years	28	28
Utility rate treatment of income taxes	3 years	17	16
Miscellaneous	Various	39	48
Total regulatory assets		$ 825	$ 304
Regulatory liabilities:			
Asset retirement removal costs (4)	(2)	$ 494	$ 451
Utility rate treatment of income taxes	3 years	43	42
Trojan refund liability	1 year	34	-
Asset retirement obligations (4)	(2)	26	28
Power cost adjustment mechanism	1 year	19	16
Trojan ISFSI pollution control tax credits	(3)	17	13
Residential Exchange Program	(5)	12	-
Miscellaneous	Various	38	24
Total regulatory liabilities		$ 683	$ 574

(1) Recovery expected over the average service life of employees. For further information see Note 2.
(2) Recovery expected over the estimated lives of the assets.
(3) Recovery period not yet determined.
(4) Included in rate base for ratemaking purposes.
(5) Recovery period continues for life of program.

As of December 31, 2008, PGE had regulatory assets other than pension and postretirement plans of $529 million not earning a return on investment, with a weighted average remaining life of 6 years. As of December 31, 2008, PGE had regulatory assets of $64 million earning a return on investment at the following rates: (1) $54 million at PGE's authorized cost of capital of 9.083% through 2006 and 8.29% beginning January 17, 2007; (2) $7 million at the approved rate for amortized deferred accounts of 4.27% for 2008; and (3) $3 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. See Note 5.

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. See Note 10.

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. See Note 11.

Asset retirement removal costs represent the costs that do not qualify as AROs and are a component of depreciation expense allowed in customer rates. Asset retirement obligation costs are recorded as a regulatory liability as they are collected in rates, and are reduced by actual removal costs incurred, in accordance with SFAS 143 and SFAS 71.

Utility rate treatment of income taxes regulatory asset or regulatory liability is established pursuant to Oregon Senate Bill 408 (SB 408). SB 408 requires regulated investor-owned utilities that provide electric or natural gas service to more closely match income tax amounts forecasted to be 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 rates 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.

Trojan refund liability was established as a result of the OPUC order issued on September 30, 2008 requiring the refund to customers in the amount of $33.1 million for the settlement of certain Trojan-related matters. The OPUC examined the rates in effect for the period April 1, 1995 through September 30, 2000 and determined the previously allowed return on the Company's investment in Trojan should be removed, the recovery of the investment should be reduced from 17 years to 10 years, and revised certain other assumptions, all of which reduced the recoverable balance as of September 30, 2000 from $180 million to $165 million. The difference of $15 million, plus accrued interest at 9.6% from September 30, 2000, is to be refunded to customers who received service from PGE during the period from October 1, 2000 to September 30, 2001. Had the Company never recovered in rates the $15 million, interest income would have been lower by approximately $2.9 million in 2008, $2.6 million in 2007, and $2.4 million in 2006.

The refund to customers of $33.1 million is classified in Revenues, net in the consolidated statement of income for the year ended December 31, 2008. Interest continues to accrue on the refund to customers at an annual rate of 9.6%. Such amount was approximately $1 million in 2008 and is included in Interest expense in PGE's consolidated statement of income for the year ended December 31, 2008.

Residential Exchange Program represents the benefits received from the BPA but not yet passed through to eligible customers.

NOTE 7: ASSET RETIREMENT OBLIGATIONS

AROs consist of the following (in millions):

	December 31, 2008	December 31, 2007
Trojan decommissioning activities	$ 37	$ 62
Utility plant	11	20
Non-utility property	10	9
Asset retirement obligations	$ 58	$ 91

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 final site restoration and 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. Final site restoration activities will begin once the spent fuel is shipped to a U.S. Department of Energy (USDOE) facility, which is not expected prior to 2033.

The USDOE has proposed that a canister-based system be required for commercial spent nuclear fuel disposal in their license application for the Monitored Geologic Repository (Yucca Mountain). The canister-based system would be the first element of an integrated three-canister system to provide containment strength and corrosion resistance to the disposal package. The estimated ARO liability does not include any cost related to this USDOE proposal as its impact is not known at this time.

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. Most decommissioning work has been completed at Bull Run as of December 31, 2008, with the demolition of the powerhouse planned for summer 2009 if an alternative use for the facility is not chosen. Environmental monitoring is scheduled to continue through 2012. Total nominal remaining costs are estimated at $3 million, or $1 million if the powerhouse is not demolished.

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

	Years Ended December 31, 2008	2007	2006
Balance as of beginning of year	$ 91	$ 134	$ 134
Liabilities incurred	-	7	-
Liabilities settled	(13)	(9)	(6)
Accretion expense	2	7	7
Revisions in estimated cash flows	(22)	(48)	(1)
Balance as of end of year	$ 58	$ 91	$ 134

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 under SFAS 71. 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.

The 2008 decrease in the Trojan ARO includes the completion and realized cost savings of all demolition activities accomplished prior to the final shipment of spent fuel, and a revision to the estimated future cash flows, including an equally-weighted assumption of final decommissioning occurring in 2034 or 2039. In 2007, PGE reduced the estimated ARO to reflect the completion of demolition activities, reduce the estimated annual cash flows related to the ISFSI operation until final decommissioning, and adjust for certain other decommissioning activities. PGE maintains a separate trust account, Nuclear decommissioning trust in the consolidated balance sheet, for funds collected from customers through rates to cover the cost of Trojan decommissioning activities. See "Trust Accounts" in Note 3 for additional information on the nuclear decommissioning trust account.

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 under SFAS 143 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 a $400 million unsecured revolving credit facility (Credit Facility) with a group of banks. The Credit Facility is available for general corporate purposes, with the maximum amount available to PGE for borrowings and/or the issuance of standby letters of credit, with $10 million of the Credit Facility scheduled to terminate in July 2012 and $390 million in July 2013. The Credit Facility allows PGE to borrow for one, two, three, or six months at a fixed interest rate established at the time of the borrowing, or at a variable interest rate for any period up to the then remaining term of the Credit Facility. The Credit Facility provides that all outstanding loans mature on the termination date of the Credit Facility, provided that annually such date may be extended for an additional year for those lenders who agree to an extension. The Credit Facility requires annual fees based on PGE's unsecured credit rating, and contains customary covenants and default provisions, including a requirement that limits consolidated indebtedness, as defined in the Credit Facility agreement, to 65% of total capitalization. As of December 31, 2008, PGE was in compliance with this covenant.

On September 15, 2008, Lehman Brothers, Inc., the parent company of Lehman Brothers Bank, FSB (Lehman), filed for protection under Chapter 11 of the U.S. Bankruptcy Code. At the time, Lehman represented $55 million, or approximately 14%, of the Credit Facility. In October 2008, $25 million of Lehman's $55 million share of the Credit Facility was reassigned to Sumitomo Mitsui Bank Corporation. The Company is in discussion with another bank for reassignment of the remaining $30 million of Lehman's share. As a result of these events, the Credit Facility has effectively been reduced to $370 million.

During December 2008, PGE obtained an additional $125 million unsecured revolving credit facility (Short-term Credit Facility) with a group of banks, which expires December 4, 2009. Advances under the Short-term Credit Facility are either at a fixed 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 Short-term Credit Facility. Similar to the Credit Facility, the Short-term Credit Facility requires annual fees based on PGE's unsecured credit rating, and contains customary covenants and default provisions, including a requirement that limits consolidated indebtedness, as defined in the Short-term Credit Facility agreement, to 65% of total capitalization. As of December 31, 2008, PGE was in compliance with this covenant.

The Company has a $400 million 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 Facility.

As of December 31, 2008, PGE had $65 million of commercial paper outstanding and borrowings of $131 million under the Credit Facility, the total of which is included in Short-term debt on the consolidated balance sheet. The Company also had issued $133 million in letters of credit. As of December 31, 2008, the aggregate unused available credit under the credit facilities is $166 million, which excludes Lehman's $30 million share of the Credit Facility.

Pursuant to an order issued by the FERC, the Company is authorized to issue short-term debt, including commercial paper, up to $550 million through February 6, 2010.

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

	Years Ended December 31,		
	2008	**2007**	**2006**
Average daily amount of short-term debt outstanding	$ 33	$ 22	$ 12
Weighted daily average interest rate [(1)]	3.8%	5.6%	5.1%
Maximum amount outstanding during the year	$ 199	$ 93	$ 81

(1) 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):

	December 31,	
	2008	**2007**
First Mortgage Bonds, rates range from 4.45% to 9.31%, with a weighted average rate of 6.0% in 2008 and 6.1% in 2007, due at various dates through 2039	$ 970	$ 970
Pollution Control Revenue Bonds:		
Port of Morrow, Oregon, 5.2% rate to 2009 and variable thereafter, due 2033	23	23
Port of Morrow, Oregon, variable rate, due 2031	-	6
City of Forsyth, Montana, 5.2% to 5.45% rate to 2009 and variable thereafter, due 2033	119	119
Port of St. Helens, Oregon, 4.8% to 5.25% rate, due 2010 to 2014	47	47
Total Pollution Control Revenue Bonds	189	195
7.875% unsecured notes, due March 10, 2010	149	149
Unamortized debt discount	(2)	(1)
Total long-term debt	1,306	1,313
Less: current portion of long-term debt	(142)	-
Long-term debt, net of current portion	$ 1,164	$ 1,313

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.

On January 15, 2009, PGE issued $130 million of its First Mortgage Bonds. The bonds were issued in two series. One series is for $67 million to mature January 15, 2016 at a fixed rate of 6.80%. The second series is for $63 million to mature on January 15, 2014 at a fixed rate of 6.50%.

Pollution Control Revenue Bonds - The current interest rate and interest period expire May 1, 2009 on $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. PGE is required under the terms of these Bonds to redeem the entire principal amount of the Bonds at a redemption price equal to 100% of the principal amount plus accrued interest on May 1, 2009. PGE has the option to have the Bonds remarketed beginning May 1, 2009 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 the remarketing. The Bonds are currently secured by a pledge of PGE First Mortgage Bonds. Upon remarketing, the Bonds could be backed by PGE First Mortgage Bonds or a bank letter of credit depending on market conditions. The Bonds are classified under the Current portion of long-term debt in the consolidated balance sheet as of December 31, 2008.

As of December 31, 2008, the future minimum principal payments on long-term debt are as follows (in millions):

Years ending December 31:	
2009	$ 142
2010	186
2011	-
2012	100
2013	100
Thereafter	778
	$ 1,306

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 Board of Directors of PGE appoints an Investment Committee, consisting of officers of the Company, which is responsible for the selection and monitoring of investments. The assets of the pension plan are held in a trust. 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 no contributions to the pension plan in 2008, 2007, and 2006, and does not expect to make any contribution in 2009. PGE is expected to make a contribution in 2010, which is estimated to be $23 million.

Effective January 31, 2009, the pension plan closed to new non-bargaining employees. For non-bargaining employees hired on or after February 1, 2009, the pension plan has been replaced with a new defined contribution plan. Employee contributions to the defined contribution plan, made on a pre-tax basis, are matched by the Company up to 5% of the participating employee's base salary. PGE also makes an additional 5% Company contribution regardless of whether or not the employee makes a contribution. There are no impacts to current participants of the pension plan.

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. Contributions made to a voluntary employees' beneficiary association trust are used to fund these plans. Costs of these plans, based upon an actuarial study, are included in rates 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 Retirement 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 and 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 February 28, 2009. For active non-bargaining employees, the Company grants a fixed dollar amount which will become available for qualified medical expenses upon their retirement.

Minimal contributions were made to the postretirement and non-bargaining HRA plans in 2008 or 2007. Contributions totaling $1 million were made to the bargaining unit HRA in 2008 and 2007. No contributions are currently expected to be made to the other postretirement plans in 2009. The measurement date for the postretirement plans is December 31.

Non-Qualified Benefit Plans - The Non-Qualified Benefit Plans (NQBP) in the following tables consist primarily of obligations for a SERP, which was closed to new participants in 1997. 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 as defined by SFAS 158. 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 Compensation Plans - In addition to the non-qualified benefit plans discussed above, PGE provides certain employees with benefits under unfunded MDCPs, whereby participants may defer a portion of their compensation, as well as other non-qualified plans for certain employees and directors. 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 included in PGE's consolidated balance sheets as of December 31, 2008 and 2007 (in millions):

	2008			2007		
	NQBP	MDCP	Total	NQBP	MDCP	Total
Non-qualified benefit plan trust	$ 18	$ 28	$ 46	$ 25	$ 44	$ 69
Non-qualified benefit plan liabilities [(1)]	23	68	91	23	63	86

(1) For the NQBP, excludes the current portion of $2 million in 2008 and $1 million in 2007, which is classified in Other current liabilities in the consolidated balance sheets.

Trust assets and obligations related to the other compensation plans are not included in the following tables.

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, 2008 and 2007 (dollars in millions):

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2008	2007	2008	2007	2008	2007
Benefit obligation:						
As of January 1	$ 475	$ 492	$ 68	$ 58	$ 24	$ 26
Service cost	12	13	2	2	-	-
Interest cost	30	27	4	4	2	1
Plan amendments	-	-	-	5	-	-
Participants' contributions	-	-	1	1	-	-
Actuarial (gain) loss	(24)	(31)	3	3	1	(2)
Prior service cost	-	-	-	-	-	1
Benefit payments	(26)	(26)	(5)	(5)	(2)	(2)
As of December 31	$ 467	$ 475	$ 73	$ 68	$ 25	$ 24
Fair value of plan assets:						
As of January 1	$ 518	$ 503	$ 27	$ 28	$ 25	$ 25
Actual return on plan assets	(145)	41	(6)	2	(5)	2
Company contributions	-	-	2	1	-	-
Participants' contributions	-	-	1	1	-	-
Benefit payments	(26)	(26)	(5)	(5)	(2)	(2)
As of December 31	$ 347	$ 518	$ 19	$ 27	$ 18	$ 25
Funded (unfunded) position as of December 31	$ (120)	$ 43	$ (54)	$ (41)	$ (7)	$ 1
Accumulated benefit plan obligation as of December 31	$ 420	$ 420	N/A	N/A	$ 25	$ 20
Classification in consolidated balance sheet:						
Noncurrent asset	$ -	$ 43	$ -	$ -	$ 18	$ 25
Current liability	-	-	-	-	(2)	(1)
Noncurrent liability	(120)	-	(54)	(41)	(23)	(23)
Net asset (liability)	$ (120)	$ 43	$ (54)	$ (41)	$ (7)	$ 1

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2008	**2007**	**2008**	**2007**	**2008**	**2007**
Amounts included in comprehensive income:						
Net actuarial (gain) loss	$ 166	$ (30)	$ 12	$ 3	$ 1	$ (2)
Prior service cost	-	-	-	5	-	1
Amortization of net actuarial loss	-	(3)	-	-	1	(1)
Amortization of prior service cost	(1)	(1)	(1)	(3)	-	-
Amortization of transition obligation	-	-	(1)	(1)	-	-
	$ 165	$ (34)	$ 10	$ 4	$ 2	$ (2)
Amounts included in AOCI [1]:						
Net actuarial loss	$ 202	$ 36	$ 21	$ 10	$ 8	$ 7
Prior service cost	2	3	7	8	-	-
	$ 204	$ 39	$ 28	$ 18	$ 8	$ 7
Assumptions used:						
Average discount rate used to calculate benefit obligation	6.90%	6.50%	5.77% - 6.09%	5.75% - 6.25%	6.90%	6.50%
Weighted average rate of increase in future compensation levels	4.42	4.42	5.07	5.07	N/A	N/A
Long-term rate of return on plan assets	9.00	9.00	7.67	8.14	N/A	N/A

(1) Amounts included in AOCI related to the Company's defined benefit pension plan and other benefits are transferred to Regulatory assets pursuant to SFAS 71. 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		
	2008	2007	2006	2008	2007	2006	2008	2007	2006
Service cost	$ 12	$ 13	$ 13	$ 2	$ 2	$ 1	$ -	$ -	$ -
Interest cost on benefit obligation	30	27	27	4	4	3	2	1	1
Expected return on plan assets	(45)	(42)	(41)	(2)	(2)	(2)	-	-	-
Amortization of transition obligation	-	-	-	1	1	1	-	-	-
Amortization of prior service cost	1	1	1	1	3	1	-	-	-
Amortization of net actuarial loss	-	3	4	-	-	1	-	1	1
Net periodic benefit cost	$ (2)	$ 2	$ 4	$ 6	$ 8	$ 5	$ 2	$ 2	$ 2

PGE estimates that $4 million will be amortized from AOCI into net periodic benefit cost in 2009, consisting of a net actuarial loss of $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					
	2009	2010	2011	2012	2013	2014 - 2018
Defined benefit pension plan	$ 30	$ 30	$ 32	$ 34	$ 35	$ 196
Other postretirement benefits	5	5	6	6	6	29
Non-qualified benefit plans	2	2	2	3	2	12
Total	$ 37	$ 37	$ 40	$ 43	$ 43	$ 237

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, an 8% annual rate of increase in the per capita cost of covered health care benefits is assumed for 2009. The rate is assumed to decrease to 5% by 2015 and remain at that level thereafter. Assumed health care cost trend rates can affect amounts reported for the health care plans.

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

Investment Policy and 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 Policy 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:

	December 31,		
	2008	**2007**	**Target**
Defined Benefit Pension Plan:			
Equity securities	68%	67%	67%
Debt securities	32	33	33
	100%	100%	100%
Other Postretirement Benefit Plans:			
Equity securities	60%	66%	60%
Debt securities	40	34	40
	100%	100%	100%
Non-Qualified Benefits Plans:			
Cash equivalents	-%	1%	-%
Debt securities	7	18	16
Equity securities	51	40	38
Insurance contracts	42	41	46
	100%	100%	100%

401(k) Retirement Savings Plan

PGE sponsors a 401(k) Plan, which covers substantially all employees. Contributions to the 401(k) Plan by eligible employees, made on a "pre-tax" basis, are matched by the Company up to a specified maximum percentage of the participating employee's base salary. For non-bargaining employees, contributions up to 6% of base pay are matched by the Company and vest after one year of service.

For bargaining employees, contributions are based upon provisions of the International Brotherhood of Electrical Workers Local 125 agreement that became effective on March 1, 2004. Contributions to the 401(k) Plan by those employees who are also covered by a defined benefit pension plan are matched by the Company at up to 6% of base pay. Contributions by those employees not covered by a defined benefit pension plan will be matched until 2009 by the Company up to 8% of base pay, based upon both the employee's age and years of service; in addition, PGE contributes from 5% to 10% of base pay, based upon the employee's age.

All contributions to the 401(k) Plan are invested in accordance with employees' investment choices. During the years ended December 31, 2008, 2007, and 2006, PGE made matching contributions of approximately $14 million, $14 million, and $13 million, respectively.

NOTE 11: INCOME TAXES

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

	Years Ended December 31,		
	2008	**2007**	**2006**
Current:			
Federal	$ 12	$ 50	$ 66
State and local	1	3	8
	13	53	74
Deferred:			
Federal	20	20	(29)
State and local	4	4	(6)
	24	24	(35)
Investment tax credit adjustments	(2)	(3)	(3)
Income tax expense	$ 35	$ 74	$ 36

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,		
	2008	**2007**	**2006**
Federal statutory tax rate	35.0%	35.0%	35.0%
Federal tax credits	(6.6)	-	-
Investment tax credits	(1.6)	(1.5)	(2.7)
State and local taxes, net of federal tax benefit	1.4	2.3	1.9
Flow through depreciation	(0.8)	(1.5)	4.7
Adjustments for previously recorded taxes	-	-	(3.6)
Other	1.0	(0.5)	(1.8)
Effective tax rate	28.4%	33.8%	33.5%

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

	December 31, 2008	December 31, 2007
Deferred income tax assets:		
Regulatory liabilities	$ 288	$ 229
Price risk management	164	34
Employee benefits	97	63
Depreciation and amortization	30	35
Other	13	13
Total deferred income tax assets	592	374
Deferred income tax liabilities:		
Depreciation and amortization	559	493
Price risk management	172	36
Employee benefits	62	27
Regulatory assets	48	59
Nuclear decommissioning trust	10	10
Other	28	15
Total deferred income tax liabilities	879	640
Deferred income tax liability, net	$ (287)	$ (266)
Classification of net deferred income taxes:		
Current deferred income tax asset	$ 151	$ 13
Noncurrent deferred income tax liability	(438)	(279)
	$ (287)	$ (266)

PGE files income tax returns in the U.S. federal jurisdiction, the states of Oregon and Montana, and certain local jurisdictions. The Company is not currently under examination by federal, state, or local tax authorities. Open tax years are 2005 and subsequent years for federal, state, and local tax purposes.

PGE generated approximately $13 million of Oregon tax credits that, due to taxable income limitations, were not utilized by Enron 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. Uncertainties existed with respect to the timing and ability by Enron to utilize the credits. To the extent that Enron was unable to utilize these credits on its tax returns, PGE utilized a portion of the tax credits to offset quarterly income tax payments due to the state of Oregon during periods subsequent to the separation with no effect on income. 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 is reflected as an adjustment to equity, net of related federal tax effect, during the year ended December 31, 2008.

As of December 31, 2008, PGE has Oregon tax credit carry forwards of $8 million expiring between 2009 and 2016.

NOTE 12: COMMON STOCK AND EMPLOYEE STOCK PURCHASE PLAN

Common Stock

On April 3, 2006, PGE and Enron entered into a separation agreement and, in accordance with the Enron Chapter 11 Plan, PGE issued 62.5 million shares of common stock and cancelled the then outstanding 42.8 million shares of common stock held by Enron Corp. Following issuance of the 62.5 million shares of common stock, PGE ceased to be a subsidiary of Enron. Approximately 35.5 million shares of PGE's common stock were initially issued to a Disputed Claims Reserve (DCR). On June 18, 2007, the DCR sold substantially all of its remaining holdings of PGE common stock in a public offering.

PGE's common stock is listed on the New York Stock Exchange under the ticker symbol "POR."

Employee Stock Purchase Plan

In May 2007, PGE shareholders approved the Portland General Electric Company 2007 Employee Stock Purchase Plan (ESPP), under which a total of 625,000 shares may be issued. The ESPP permits all eligible Company 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 worth of 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, 2008 and 2007, the Company issued 25,586 shares and 8,179 shares, respectively, under the ESPP, with proceeds totaling approximately $0.5 million and $0.2 million, respectively.

NOTE 13: STOCK-BASED COMPENSATION EXPENSE

In 2006, PGE adopted the Portland General Electric Company 2006 Stock Incentive Plan (the Plan). Under the Plan, PGE 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 4,286,595 shares remain available for future issuance as of December 31, 2008.

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. Vesting of Performance Stock Units will be 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 will be 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.

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

	Units	Weighted Average Grant Date Fair Value
Outstanding as of December 31, 2005	-	$ -
Granted	188,248	24.97
Forfeited	(3,301)	26.21
Vested	(4,767)	25.82
Outstanding as of December 31, 2006	180,180	24.97
Granted	100,425	28.44
Forfeited	(7,194)	25.14
Vested	(20,160)	25.76
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

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 shareholders' 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 2,792 shares in 2008 and 3,319 shares in 2007.

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, 2008, 2007 and 2006, PGE recorded $4 million, $3 million and $1 million, respectively, of stock-based compensation expense, which is included in Administrative and other expense in the consolidated statements of income. As of December 31, 2008, unrecognized stock-based compensation expense was $3.5 million, of which $2.6 million and $0.9 million is expected to be expensed in 2009 and 2010, respectively. Stock-based compensation expense was calculated assuming the attainment of performance goals that would allow the vesting of 100%, 136%, and 129% of awarded Performance Stock Units for 2008, 2007, and 2006, respectively, with an estimated 5% 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, 2008, 2007, or 2006.

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,		
	2008	**2007**	**2006**
Numerator (in millions):			
Net income available for common shareholders	$ 87	$ 145	$ 71
Denominator (in thousands):			
Weighted average common shares outstanding - basic	62,544	62,512	62,501
Dilutive effect of restricted stock units and employee stock purchase plan shares	37	22	4
Weighted average common shares outstanding - diluted	62,581	62,534	62,505
Earnings per share - basic and diluted	$ 1.39	$ 2.33	$ 1.14

Basic and diluted earnings per share amounts are calculated based on actual amounts. Accordingly, basic and diluted earnings per share amounts as presented in the table above and on the consolidated statements of income may not necessarily recalculate based on the rounded amounts presented for both net income and weighted average shares outstanding.

NOTE 15: COMMITMENTS AND GUARANTEES

Commitments

As of December 31, 2008, PGE's future minimum payments pursuant to purchase obligations for the following five years and thereafter are as follows (in millions):

	Payments Due						
	2009	2010	2011	2012	2013	Thereafter	Total
Capital expenditures	$ 423	$ 215	$ 17	$ 8	$ 16	$ 21	$ 700
Purchased power and fuel:							
Electricity purchases	362	81	75	64	64	553	1,199
Capacity contracts	25	22	21	20	20	58	166
Public Utility Districts	8	7	7	5	5	39	71
Natural gas	69	38	31	15	14	38	205
Coal and transportation	19	13	11	3	3	-	49
Operating leases	7	7	7	8	8	212	249
Total	$ 913	$ 383	$ 169	$ 123	$ 130	$ 921	$2,639

Capital Expenditures - Certain commitments have been made for capital and other purchases for 2009 and beyond. Such commitments include those related to hydro license agreements, Biglow Canyon Phases II and III, 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 2035, and power capacity contracts through 2016. As of December 31, 2008, PGE has power sale contracts with counterparties of approximately $136 million in 2009, $5 million annually in 2010 and 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, 2008, PGE was owed 185 MWh of electricity, all of which are expected to be delivered by the end of February 2009. 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, 2008, PGE owed 8,706 MWh of electricity, all of which are expected to be delivered by the end of February 2009.

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. Selected information regarding these projects is summarized as follows (dollars in millions):

	Revenue Bonds as of December 31, 2008	PGE Share		Contract	PGE Cost, including Debt Service		
		Output	Capacity (1)	Expiration	2008	2007	2006
Rocky Reach	$ 321	12.0%	156	2011	$ 9	$ 9	$9
Priest Rapids	248	4.1%	39	2052	2	3	3
Wanapum	422	18.7%	194	(2)	12	10	8
Wells	187	19.4%	156	2018	8	8	7
Portland Hydro	17	100.0%	36	2017	3	4	4

(1) In MW.
(2) Expires at the end of the license term to be determined by the FERC.

Under contracts with the public utility districts, PGE has acquired a percentage of the output (Allocation) of Rocky Reach, Priest Rapids, 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, Wanapum and Wells, PGE would be allocated up to a cumulative maximum of 25% of the defaulting purchaser's percentage Allocation. For Priest Rapids, 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 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 $8 million in 2008, 2007, and 2006.

The future minimum operating lease payments presented in the table above is net of sublease income of $3 million in 2009, $2.9 million in 2010, $2.3 million in 2011, $1.5 million in 2012 and $0.6 million in 2013. Sublease income is classified as Miscellaneous income in the consolidated statements of income and was $3 million in 2008, 2007, and 2006.

Guarantees

PGE entered into a sale transaction in 1985 in which it sold an undivided 15% interest in Boardman and a 10.714% undivided interest in the Pacific Northwest Intertie (Intertie) transmission line (jointly the Boardman Assets) to an unrelated third party (Purchaser). The Purchaser leased the Boardman Assets to a lessee (Lessee) unrelated to PGE or the Purchaser. Concurrently, PGE assigned to the Lessee certain agreements for the sale of power and transmission services from Boardman and the Intertie (P&T Agreements) to a regulated electric utility (Utility) unrelated to PGE, the Purchaser, or the Lessee. The payments by the Utility under the P&T Agreements exceed the payments to be made by the Lessee to the Purchaser under the lease. In exchange for PGE undertaking certain obligations of the Lessee under the lease, the Lessee reassigned to PGE certain rights, including the excess payments, under the P&T Agreements. However, in the event that the Utility defaults on the payments it owes under the P&T Agreements, PGE may be required to pay the damages owed by the Lessee to the Purchaser under the lease. Assuming no recovery from the Utility and no reduction in damages from mitigating sales or leases related to the Boardman Assets and P&T Agreements, the maximum amount that would be owed by PGE in 2009 is approximately $147 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, 2008, management believes the likelihood is remote that PGE would be required to perform or otherwise incur any significant losses. The Company has not recorded any liability with respect to these indemnifications.

NOTE 16: VARIABLE INTEREST ENTITIES

Pursuant to FIN 46R, the primary beneficiary of a VIE is required to consolidate the VIE and disclose certain information about its significant interest in the VIE. The primary beneficiary of a VIE is the entity that receives the majority of a VIE's expected losses, expected residual returns, or both. FIN 46R also provides the guidance for determining whether an entity is a VIE.

PGE has determined it is the primary beneficiary of two VIEs which were formed in late 2008, SunWay 1, LLC (SunWay 1) and SunWay 2, LLC (SunWay 2) (or collectively, LLCs). Both entities 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 1.2 MW of electricity.

PGE is the Managing Member in each of the LLCs, representing less than 1% equity interest in each entity, and a financial institution is the Investor Member, representing 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 LLC and the Investor Member will own 5%, without the exchange of any consideration. PGE expects to purchase the residual 5% interest from the Investor Member at the then fair market value of the LLCs' net assets.

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) based on projections prepared in accordance with the operating agreement, PGE will absorb a majority of the expected losses of the LLCs; (2) PGE expects to own 100% of the LLCs shortly after five years have lapsed, at which time the facilities will have approximately 75% of their estimated useful life remaining; and (3) PGE has the expertise to own and operate electric generating facilities and is authorized to operate the LLCs pursuant to the operating agreements.

PGE's consolidated financial statements as of and for the year ended December 31, 2008 reflect the consolidation of SunWay 1 and SunWay 2.

There are no restrictions on SunWay 1 and SunWay 2's assets included in PGE's consolidated balance sheet as of December 31, 2008, with the carrying amounts of those assets totaling $8.8 million, substantially all of which are classified as Electric utility plant, net in the consolidated balance sheet. As of December 31, 2008, SunWay 1 and SunWay 2's total liabilities amounted to $8.5 million, substantially all of which are classified as Short-term debt in PGE's consolidated balance sheet.

NOTE 17: JOINTLY-OWNED PLANT

PGE has interests in three jointly-owned generating facilities. Under the joint operating agreements, each participating utility 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, 2008, PGE had the following investments in jointly-owned plant (dollars in millions):

	PGE Share	In-service Date	Plant In-service	Accumulated Depreciation (1)	Construction Work In Progress
Boardman	65.00%	1980	$ 425	$ 270	$ 6
Colstrip 3 and 4	20.00	1986	487	307	4
Pelton/Round Butte	66.67	1958/1964	124	47	70
Total			$ 1,036	$ 624	$ 80

(1) Excludes asset retirement obligations and accumulated asset retirement removal costs.

NOTE 18: CONTINGENCIES

Legal Matters

Trojan Investment Recovery

Background. In 1993, PGE closed the Trojan Nuclear Plant as part of the Company's least cost planning process. PGE sought full recovery of, and a rate of return on, its Trojan plant costs, including decommissioning, in a general rate case filing with the OPUC. In 1995, the OPUC issued a general rate order which granted the Company recovery of, and a rate of return on, 87% of its remaining investment in Trojan plant costs, and full recovery of its estimated decommissioning costs through 2011.

Court Proceedings on OPUC Authority to Grant Recovery of Return on Trojan Investment. Numerous challenges, appeals and reviews were subsequently filed in the Marion County Circuit Court (Circuit Court), the Oregon Court of Appeals, and the Oregon Supreme Court 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 Citizens' Utility Board (CUB) and the Utility Reform Project (URP). The Oregon Court of Appeals issued an opinion in 1998, stating that the OPUC does not have the authority to allow PGE to recover a return on the Trojan investment, but upholding the OPUC's authorization of PGE's recovery of the Trojan investment and ordering remand of the case to the OPUC. PGE, the OPUC, and the URP each requested the Oregon Supreme Court conduct a review of the Court of Appeals decision. On November 19, 2002, the Oregon Supreme Court dismissed the petitions for review. As a result, the 1998 Oregon Court of Appeals opinion stands and the case was remanded to the OPUC (1998 Remand).

Settlement of Court Proceedings on OPUC Authority. In 2000, while the petitions for review of the 1998 Oregon Court of Appeals decision were pending at the Oregon Supreme Court, 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 the Trojan plant. The URP did not participate in the settlement. The settlement, which was approved by the OPUC in September 2000, allowed PGE to remove from its balance sheet the remaining before-tax investment in Trojan of approximately $180 million at September 30, 2000, along with several largely offsetting regulatory liabilities.

Challenge to Settlement of Court Proceeding. The URP filed a complaint with the OPUC challenging the settlement agreements and the OPUC's September 2000 order. 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. On October 10, 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.

Remand of 2002 Order. As a result of the Oregon Court of Appeals remand of the 2002 Order, the OPUC considered the following issues:

- Whether the OPUC has authority to engage in retroactive ratemaking; and
- What prices would have been if, in 1995, the OPUC had interpreted the law to prohibit a return on the Trojan investment.

On September 30, 2008, the OPUC issued an order that requires PGE to refund $33.1 million to certain customers. The refund relates to the unamortized Trojan balance on September 30, 2000, as discussed below.

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.

The OPUC examined the rates in effect for the period April 1, 1995 through September 30, 2000 and determined what rates during this period would have been if, in 1995, the OPUC had interpreted the law to prohibit a return on the Trojan investment. The OPUC removed the previously allowed return on the Company's Trojan investment during the period, reduced the recovery period from 17 to 10 years, and revised certain other assumptions, all of which reduced the recoverable balance as of September 30, 2000 from $180.5 million to $165.1 million. The OPUC ruled that the difference of $15.4 million, plus interest at 9.6% from September 30, 2000, should be refunded 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, results in a total refund of $33.1 million as of September 30, 2008. The order also provides that the total refund amount will accrue interest at 9.6% from October 1, 2008 until all refunds are issued to customers.

As a result of this order, PGE recorded, as a regulatory liability, the total refund due to customers of $33.1 million, which reduced 2008 revenues. The URP and the plaintiffs in the class actions described below have separately appealed the order to the Oregon Court of Appeals. The full text of OPUC Order No. 08-487 is available on its Internet website at www.puc.state.or.us. On December 1, 2008, the OPUC issued an order that suspended the requirements imposed on PGE by the refund methodology outlined in the September 30, 2008 order for 60 days. On January 24, 2009, counsel for the URP and the Class Action Plaintiffs filed a motion with the Oregon Court of Appeals requesting a stay of the refund pending final disposition of their appeal. On February 2, 2009, the OPUC issued Order No. 09-039, which suspended the requirements imposed on PGE by the refund methodology pending the Court of Appeals decision on the Motion for Stay filed by the URP and Class Action Plaintiffs. Based on the OPUC orders and subsequent request for stay, the timing of refunds to customers is uncertain, but could occur during 2009.

Class Actions. In a separate legal proceeding, two class action suits were filed in Circuit Court against PGE on January 17, 2003 on behalf of two classes of electric service customers. One 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 other 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, as a result of the inclusion of a return on investment of Trojan in the prices PGE charged its customers.

On December 14, 2004, the judge granted the Class Action Plaintiffs' motion for Class Certification and Partial Summary Judgment and denied PGE's motion for Summary Judgment. On March 3, 2005 and March 29, 2005, PGE filed two Petitions for an Alternative 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, and 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 the class action proceedings until the OPUC responded with respect to certain issues on remand to the 2003 Remand (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 1995 through October 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 further stated 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 Circuit Court for disposition of whatever issues remain unresolved from the remanded OPUC proceedings.

On October 5, 2006, the Circuit Court issued an Order of Abatement in response to the ruling of the Oregon Supreme Court, abating the class actions, but inviting motions to lift the abatement after one year. On October 17, 2007, the plaintiffs filed a motion to lift the abatement. A decision on the motion to lift the abatement is pending.

Management cannot predict the ultimate outcome of the above matters. However, it believes 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 operation and cash flows for a future reporting period.

Regulatory Matters

Colstrip Royalty Claim

Western Energy Company (WECO) supplies coal from the Rosebud Mine in Montana under a Coal Supply Agreement and a Transportation Agreement with owners of Colstrip Units 3 and 4 coal plant (Colstrip), in which PGE has a 20% ownership interest. In 2002, 2003, and 2006, WECO received orders from the Office of Minerals Revenue Management of the U.S. Department of the Interior (USDI) that asserted underpayment of royalties and taxes by WECO related to transportation of coal from the mine to Colstrip. In May 2005, WECO received a Preliminary Assessment Notice from the Montana Department of Revenue (MDOR), asserting claims similar to those of the USDI.

In October 2008, PGE and the other owners of Colstrip agreed with WECO to pay a portion of the taxes and royalties that WECO is required to pay to the MDOR and the USDI for both past and future periods. On October 23, 2008, WECO entered into an agreement with MDOR that settles all claims for years prior to 2008 and establishes a method for calculating taxes and royalties for subsequent periods. Management believes that PGE's share of WECO's obligation to pay royalties, taxes and interest to the USDI and MDOR for periods through December 31, 2008 would be approximately $2.5 million and during 2008 accrued a reserve of that amount. As of December 31, 2008, the Company had paid $0.4 million to WECO related to the MDOR settlement.

PGE estimates that the Company's share of royalties, taxes, and interest for future periods will be approximately $0.2 million per year. The Company has applied to the OPUC for authorization to recover $2.2 million in future prices, relating to years prior to 2007. Amounts related to 2007 and 2008 were included as qualifying power costs in the calculation of the Company's PCAM for those years. The PCAM adjustment approved by the OPUC for 2007 costs, included these costs. The 2008 costs will be considered by the OPUC during 2009. The OPUC has informed PGE that it will withhold any decision on PGE's request for recovery of costs prior to 2007 until WECO settles the USDI claims and all costs to PGE are determinable. PGE believes it is probable that the OPUC will allow recovery of the $2.2 million of incremental costs for the 2006 and prior time period. Accordingly, the Company recorded a $2.2 million regulatory asset and reduced Purchased power and fuel expense, in the fourth quarter of 2008.

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 (Pacific Northwest Refund proceeding). 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, 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 have been filed with the court, with a decision now pending.

The settlement between PGE and certain other parties in the California refund case in Docket No. EL00-95, *et seq*., approved by the FERC on May 17, 2007, resolves all claims as 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 does 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, or whether the FERC will order refunds in the Pacific Northwest, and if so, how such refunds would be calculated. Management believes 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 operation and cash flows in future reporting periods.

Complaint and Application for Deferral – Income Taxes

On October 5, 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 are not being 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.

On August 14, 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, without prejudice, on grounds that it was superfluous to the Complainants' request 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. The order also provided that the OPUC would review PGE's earnings at the time it considers amortization of the deferral. PGE understands that the OPUC will consider the potential impact of the deferral on PGE's earnings over a relevant 12-month period, which will include the Deferral Period.

On December 1, 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; (ii) a relevant 12-month period would be the 12-month period ended September 30, 2006; and (iii) PGE's earnings over such period would preclude any refund. The OPUC has indicated that it will determine whether any necessary rate adjustment should be made to amortize the deferral granted in its August 14, 2007 order.

On October 15, 2007, PGE filed a petition for judicial review with the Oregon Court of Appeals, seeking review of the OPUC's August 14, 2007 order. The Court of Appeals has granted PGE's request to stay the proceedings pending an OPUC order in the matter.

Management cannot predict the ultimate outcome of this matter. However, based on the information currently known to management, it believes this matter will not have a material adverse effect on PGE's financial condition, results of operation or cash flows.

FERC Investigation

In May 2008, PGE received a notice of a preliminary non-public investigation from the FERC Division of Investigations concerning PGE's compliance with its Open Access Transmission Tariff. The investigation involves certain issues identified during an audit by FERC staff.

Management cannot predict the final outcome of the investigation or what actions, if any, the FERC will take or require the Company to take. Management believes 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 operation and cash flows in future reporting periods.

Environmental Matters

Portland Harbor

Since 1973, PGE has operated a substation on land owned by the Company located near the Willamette River. A 1997 investigation by the U.S. Environmental Protection Agency (EPA) of a segment of the river known as the Portland Harbor revealed significant contamination of river sediments. The EPA subsequently included this segment on the federal National Priority List pursuant to the federal Comprehensive Environmental Response, Compensation, and Liability Act as a federal Superfund site and listed sixty-nine Potentially Responsible Parties (PRPs), including PGE.

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.

On January 22, 2008, PGE received a Section 104(e) Information Request from the EPA requiring the Company to provide information concerning its properties in or near the segment of the river being examined in the RI/FS, as well as several miles beyond that 5.7 mile segment. PGE has requested, and the EPA granted, an extension until August 2009 for the Company to respond.

The EPA will determine the boundaries of the site at the conclusion of the RI/FS in a Record of Decision, expected in 2010. The EPA will document its findings in the Record of Decision and select a preferred cleanup alternative.

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. Management believes 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 operation and cash flows in future reporting periods.

PGE filed an application with the OPUC in March 2008 requesting deferred accounting, for later ratemaking treatment, of incremental costs related to investigation and remediation costs incurred in relation to the Portland Harbor site. In February 2009, the OPUC approved PGE's application, effective March 31, 2008. Ratemaking treatment will be reserved for a future regulatory proceeding that provides for both a prudency review with respect to the costs incurred and a regulated earnings test. As a result, there can be no assurance that recovery of all of these costs will be granted.

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. On September 29, 2003, the Harbor Oil facility was included on the federal 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. The letter started a period for the PRPs to participate in negotiations with the EPA to reach a settlement to conduct or finance an RI/FS of the Harbor Oil site. On May 31, 2007, an Administrative Order on Consent was signed by the EPA and six other parties, including PGE, to implement an RI/FS at the Harbor Oil site. The EPA has approved an RI/FS work plan. On-site sampling commenced in 2008 and has yet to be completed.

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. Management believes 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 operation and cash flows in future reporting periods.

PGE filed an application with the OPUC in March 2008 requesting deferred accounting, for later ratemaking treatment, of incremental costs related to RI/FS work and any resulting remediation costs incurred in relation to the Harbor Oil site. In February 2009, the OPUC approved PGE's application, effective March 31, 2008. Ratemaking treatment will be reserved for a future regulatory proceeding that provides for both a prudency review with respect to the costs incurred and a regulated earnings test. As a result, there can be no assurance that recovery of all of these costs will be granted.

Other Matters

PGE is subject to other regulatory 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 resolving such matters will not have a material adverse effect on its financial position, results of operation, or cash flows, these matters are subject to inherent uncertainties and management's view of these matters may change in the future.

NOTE 19: RELATED PARTY TRANSACTIONS

Prior to April 3, 2006, PGE was a wholly-owned subsidiary of Enron and was included in Enron's consolidated income tax return. Pursuant to this relationship, PGE was billed for a portion of Enron's costs incurred related to the resolution of issues associated with Enron's bankruptcy and litigation related to certain employee benefit plans in which PGE employees previously participated. Additionally, PGE made payments to Enron for PGE's income tax liabilities.

During 2006, PGE recognized a reduction of $1 million in administrative and other expense related to the final resolution of costs billed by Enron in 2005 for issues associated with its bankruptcy and litigation related to employee benefit plan matters described above and paid Enron $17 million for its current income taxes payable for the first quarter of 2006. As of December 31, 2006, and since that date, PGE had no outstanding amounts due to Enron.

QUARTERLY FINANCIAL DATA (Unaudited)

	Quarter Ended			
	March 31	June 30	September 30	December 31
2008	(In millions, except per share amounts)			
Revenues (a)	$ 471	$ 425	$ 400	$ 449
Income from operations (a)	63	76	21	57
Net income (a)	28	39	-	20
Earnings per share - basic and diluted (d)	0.44	0.63	-	0.32
2007				
Revenues	$ 436	$ 402	$ 435	$ 470
Income from operations (b) (c)	90	79	45	55
Net income (b)	55	46	20	24
Earnings per share - basic and diluted (d)	0.88	0.73	0.32	0.40

(a) Revenues for the third quarter of 2008 include the accrual of a refund to customers in the amount of $33.1 million pursuant to an OPUC order issued September 30, 2008 related to the settlement of various Trojan matters, which reduced Net income by approximately $20 million.

(b) Operating results for the first quarter of 2007 include the approximate $13 million after-tax effect of the deferral of a portion of Boardman replacement power costs for future rate recovery (as approved by the OPUC) and the approximate $4 million after-tax effect of the settlement between PGE and certain California parties related to wholesale energy transactions in the western energy markets during 2000-2001.

(c) To conform to the 2008 financial statement presentation, income taxes have been reclassified and are no longer included in operating expenses. Accordingly, Income from operations amounts for 2007 presented in the table above differ from the amounts presented for Quarterly Financial Data in PGE's Form 10-K for the year ended December 31, 2007 filed with the SEC on February 27, 2008.

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

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

None.

ITEM 9A. CONTROLS AND PROCEDURES.

(a) Disclosure Controls and Procedures

Management of the Company, under the supervision and with the participation of the Co-Chief Executive Officer, James J. Piro, 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 Co-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 Co-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 Co-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 Co-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, 2008, the Company's internal control over financial reporting is effective.

The Company’s internal control over financial reporting, as of December 31, 2008, 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, 2008.

(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 2008 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 AND EXECUTIVE OFFICERS OF THE REGISTRANT.

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 13, 2009.

The information required to be furnished pursuant to this item with respect to the identification of the Audit Committee, the Audit Committee financial expert, and the Company’s code of ethics will be set forth under the caption “Corporate Governance” in the definitive proxy statement and is incorporated herein by reference.

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,” “Compensation Committee Interlocks and Insider Participation,” “Compensation and Human Resources Committee Report,” “Compensation Discussion and Analysis,” and “Executive Compensation” 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 13, 2009.

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 13, 2009.

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 13, 2009.

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 May 13, 2009.

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*	Amended and Restated Articles of Incorporation of Portland General Electric Company (Form 8-K filed April 3, 2006, Exhibit 3.1).
3.2*	Fifth Amended and Restated Bylaws of Portland General Electric Company (Form 8-K filed August 8, 2007, 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).
4.3*	Fifty-sixth Supplemental Indenture dated May 1, 2006 (Form 8-K filed May 25, 2006, Exhibit 4).
4.4*	Fifty-seventh Supplemental Indenture dated December 1, 2006 (Form 8-K filed December 21, 2006, Exhibit 4).
4.5*	Fifty-eighth Supplemental Indenture dated April 1, 2007 (Form 8-K filed April 12, 2007, Exhibit 4).
4.6*	Fifty-ninth Supplemental Indenture dated October 1, 2007 (Form 8-K filed October 5, 2007, Exhibit 4).
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).
(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).

Exhibit Number	Description
10.3*	Credit Agreement dated December 8, 2008, between Portland General Electric Company, Wells Fargo Bank, National Association, as Administrative Agent, and a group of lenders (Form 8-K filed December 10, 2008, Exhibit 4.1).

Exhibits 10.4 through 10.15 were filed in connection with the Company's 1985 Boardman/ Intertie Sale:

Exhibit Number	Description
10.4*	Long-term Power Sale Agreement dated November 5, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10).
10.5*	Long-term Transmission Service Agreement dated November 5, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10).
10.6*	Participation Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10).
10.7*	Lease Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10).
10.8*	PGE-Lessee Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10).
10.9*	Asset Sales Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10).
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).
10.11*	Supplemental Bill of Sale dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10).
10.12*	Trust Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10).
10.13*	Tax Indemnification Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10).
10.14*	Trust Indenture, Mortgage and Security Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10).
10.15*	Restated and Amended Trust Indenture, Mortgage and Security Agreement dated February 27, 1986 (Form 10-K for the year ended December 31, 1997, Exhibit 10).
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 March 4, 2005 (Form 10-K filed March 11, 2005, Exhibit 10). +
10.19*	Portland General Electric Company Management Deferred Compensation Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.1). +

Exhibit Number	Description
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). +
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 Directors' Restricted Stock Unit Agreement (Form 8-K filed July 14, 2006, Exhibit 10.1). +
10.28*	Form of Officers' Performance Stock Unit Agreement (Form 8-K filed July 14, 2006, Exhibit 10.2). +
10.29*	Form of Officers' Performance Stock Unit Agreement (Form 8-K filed March 13, 2008, Exhibit 10.1). +
10.30*	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 Co-Chief Executive Officer.
31.2	Certification of Chief Financial Officer.
(32)	**Section 1350 Certifications**
32.1	Certifications of Co-Chief Executive Officer and Chief Financial Officer.

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.

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* - Incorporated by reference as indicated.

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

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 25, 2009.

PORTLAND GENERAL ELECTRIC COMPANY

By: /s/ James J. Piro

James J. Piro
Co-Chief Executive Officer and President

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 and on February 25, 2009.

Signature	Title
/s/ James J. Piro James J. Piro	*Co-Chief Executive Officer, President and Director* (principal executive officer)
/s/ Maria M. Pope Maria M. Pope	*Senior Vice President, 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/ Peggy Y. Fowler Peggy Y. Fowler	*Co-Chief Executive Officer and 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*