UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, DC 20549

FORM 10-Q

x **Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the quarterly period ended December 31, 2011

OR

o **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

Commission File Number 001-07172

BRT REALTY TRUST

(Exact name of Registrant as specified in its charter)

Massachusetts	**13-2755856**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

60 Cutter Mill Road, Great Neck, NY	**11021**
(Address of principal executive offices)	(Zip Code)

516-466-3100

(Registrant s telephone number, including area code)

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o

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

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 small reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer o	Accelerated filer x
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No x

Indicate the number of shares outstanding of each of the issuer s classes of stock, as of the latest practicable date.

14,076,712 Shares of Beneficial Interest,

$3 par value, outstanding on February 5, 2012

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BRT REALTY TRUST AND SUBSIDIARIES

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Part 1 - FINANCIAL INFORMATION

Item 1. Financial Statements

BRT REALTY TRUST AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(Dollars in thousands, except share data)

	December 31, 2011 (Unaudited)	September 30, 2011
ASSETS		
Real estate loans, all earning interest	$ 52,679	$ 67,266
Deferred fee income	(880)	(576)
	51,799	66,690
Real estate loan held for sale		8,446
Real estate properties net of accumulated depreciation of $2,689 and $2,511	59,875	59,277
Investment in unconsolidated ventures	1,014	4,247
Cash and cash equivalents	76,589	44,025
Available-for-sale securities at market	3,601	2,766
Other assets	5,424	5,561
Total Assets	$ 198,302	$ 191,012
LIABILITIES AND EQUITY		
Liabilities:		
Junior subordinated notes	$ 37,400	$ 37,400
Mortgages payable	18,629	14,417
Accounts payable and accrued liabilities	1,164	948
Deposits payable	2,099	2,518
Total Liabilities	59,292	55,283
Commitments and contingencies		
Equity:		
BRT Realty Trust shareholders equity:		
Preferred shares, $1 par value:		
Authorized 10,000 shares, none issued		
Shares of beneficial interest, $3 par value:		
Authorized number of shares, unlimited, 13,941 and 14,994 issued	41,822	44,981
Additional paid-in capital	167,245	171,889
Accumulated other comprehensive income net unrealized gain on available-for-sale securities	655	278
Accumulated deficit	(73,141)	(77,015)
Cost of 492 and 1,422 treasury shares of beneficial interest	(3,824)	(11,070)
Total BRT Realty Trust shareholders equity	132,757	129,063
Non-controlling interests	6,253	6,666
Total Equity	139,010	135,729
Total Liabilities and Equity	$ 198,302	$ 191,012

See accompanying notes to consolidated financial statements.

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BRT REALTY TRUST AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

(Dollars in thousands, except share data)

	Three Months Ended December 31,	
	2011	**2010**
Revenues:		
Interest on real estate loans	$ 1,910	$ 1,156
Loan fee income	342	243
Rental revenue from real estate properties	768	854
Recovery of previously provided allowances	7	
Other, primarily investment income	127	199
Total revenues	3,154	2,452
Expenses:		
Interest on borrowed funds	467	657
Advisor s fees, related party	171	221
Foreclosure related professional fees		190
General and administrative including $279 and $202 to related party	1,674	

Item 4. Submission of Matters to a Vote of Security Holders

None.

Executive Officers of the Registrant [1]

Name	Age	
Peggy Y. Fowler Chief Executive Officer and President	55	Appo Also until Febr Serv Inc.[2 June

James J. Piro Executive Vice President, Finance, Chief Financial Officer and Treasurer		54		Appo Serv Fina until Chie of Po affili
Stephen R. Hawke Senior Vice President, Customer Service and Delivery		57		Appo Serv Deli curre Engi Serv Serv Utili 2003
Arleen N. Barnett Vice President, Administration, Corporate Compliance Officer		55		Appo Serv Info Com appo Presi until Reso (an E 2003
Carol A. Dillin Vice President, Public Policy		49		A p p Febr Affa April

Executive Officers of the Registrant (1)

Name		Age		
Campbell A. Henderson		53		Appo Serv

Vice President, Information Technology and Chief Information Officer				Man until Chie Asso from Chie Indu
Ronald W. Johnson Vice President, Customers and Economic Development		56		Appo Serv Stra July Serv Reso from
Pamela G. Lesh Vice President, Regulatory Affairs and Strategic Planning		50		Appo Serv Affa posit and June
James F. Lobdell Vice President, Power Operations and Resource Planning		48		Appo Serv Sept posi Man May Dire to M
Joe A. McArthur Vice President, Customer Service		59		Appo Serv July
Douglas R. Nichols Vice President,		64		Appo Serv Febr

General Counsel and Secretary				Serv May Cour Enro

Executive Officers of the Registrant [1]

Name		Age		
Stephen M. Quennoz Vice President, Nuclear and Power Supply/ Generation		59		App Serv Janu Serv Ope 2001

(1)

As of February 28, 2007. Officers of PGE are elected for one-year terms or until their successors are elected and qualified.

(2)

Portland General Holdings, Inc. (PGH) filed for bankruptcy protection on June 27, 2003. PGH's bankruptcy case was dismissed by the Bankruptcy Court on October 20, 2005. PGH, a wholly-owned subsidiary of Enron, remained with Enron following the April 3, 2006 separation of PGE from Enron.

Part II

Item 5. Market for Registrant's Common Equity, Related Stockholder

Matters and
Issuer Purchases
of Equity
Securities

In accordance with Enron's Chapter 11 Plan, on April 3, 2006 PGE issued 62.5 million shares (of 80 million, no par value, shares authorized) of new PGE common stock. Approximately 27 million shares of the new PGE common stock were initially issued to the Debtors' creditors holding allowed claims, and approximately 35.5 million shares were issued to a the DCR, where the shares will be held to be released over time to the Debtors' creditors holding allowed claims, in accordance with the Chapter 11 Plan. Distributions are generally scheduled for April and October of each year. Since the initial distribution, approximately 3.5 million shares of PGE common stock have been released from the DCR, with approximately 32 million shares held in the DCR as of February 1, 2007. The 42.8 million shares of PGE common stock previously held by Enron were cancelled.

The new PGE common stock is traded on the New York Stock Exchange under the ticker symbol POR. At January 31, 2007, there were 1,355 holders of record of PGE's common stock. Quarterly stock prices since the April 3, 2006 issuance of new PGE common stock are indicated in the table below.

	Price Range		Dividends Declared Per Share
2006 - Quarter	High	Low	
1	-	-	-
2	$ 31.11	$ 24.97	$0.22
3	26.60	24.25	0.22
4	28.65	24.12	0.22

2005 - Quarter						
1		-		-		-
2		-		-		-
3		-		-		$150 million (
4		-		-		-

(*) Paid to Enron in July 2005.

The OPUC order approving the issuance of new PGE common stock includes a stipulation containing several conditions, including a requirement that, after issuance of the new common stock, PGE cannot pay common stock dividends that would reduce the Company's common equity capital below 48% of total capitalization (excluding short-term borrowings) without prior OPUC approval. The requirement is reduced to 45% when the DCR holds between 20% and 40% of the issued and outstanding common stock of PGE, with no minimum common equity capital percentage requirement when the DCR holds less than 20% of the issued and outstanding common stock of PGE. At February 1, 2007, the DCR held approximately 51% of the total outstanding common stock of PGE. Other conditions include a requirement that the OPUC be notified (simultaneously with the public) of any dividend declared by PGE's Board of Directors.

PGE expects to pay regular quarterly dividends on its common stock. However, the declaration of such dividends is at the discretion of the Company's Board of Directors and is not guaranteed. The amount of common dividends will depend upon PGE's results of operations and financial condition, future capital expenditures and investments, any applicable regulatory and contractual restrictions, and other factors that the Board of Directors considers relevant.

Item 6. Selected Financial Data

	For the Years Ended December 31			
	2006	2005	2004	2003
	(In Millions, except per share amounts			
Operating Revenues (a)	$ 1,520	$ 1,446	$ 1,454	$ 1,752
Net Operating Income	121	126	150	124
Net Income	71	64	92	60
Basic earnings per common share (b)	1.14	1.02	1.48	0.94
Diluted earnings per common share (b)	1.14	1.02	1.48	0.94
Dividends declared per common share	0.68	*	*	*
Total Assets (c)	3,767	3,638	3,403	3,372
Long-Term Debt (d)	1,003	890	922	983

(a) Operating Revenues for 2003 through 2006 reflect the October 1, 2003 adoption of EITF 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, and 'Not Held for Trading Purposes'." EITF 03-11 requires that realized gains and losses associated with non-trading derivative activities that are not physically settled be reported on a net basis. Prior to October 1, 2003, such settlements were recorded on a gross basis in both Operating Revenues and Purchased Power and Fuel expense. Amounts for periods prior to October 1, 2003 were not reclassified. Accordingly, Operating Revenues for these periods are not fully comparable to the years 2003 through 2006 and do not reflect PGE's current reporting. For further information, see Note 1, Summary of Significant Accounting Policies, in the Notes to Financial Statements.

(b) In accordance with Enron's Chapter 11 Plan, on April 3, 2006 PGE issued 62.5 million shares (of 80 million, no par value, shares authorized) of new PGE common stock. The 42.8 million shares of PGE common stock previously held by Enron were cancelled. PGE accounted for the stock issuance in the same manner as a stock split and has retroactively adjusted all periods presented. Accordingly, both basic and diluted earnings per common share for all years presented are based on the number of new shares.

(c) Amounts for 2002 were reclassified from those reported in the Form 10-K to reflect the transfer of accumulated asset retirement removal costs from Accumulated Depreciation to Other liabilities, in accordance with SFAS No. 143, Asset Retirement Obligations, and SFAS No. 71, Accounting for the Effects of Certain Types of Regulation.

(d) Includes long-term debt and preferred stock subject to mandatory redemption requirements.

* Not meaningful as the Company was a wholly-owned subsidiary of Enron.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation

Overview

General - Portland General Electric Company (PGE, or the Company) is a single 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 states and Canada. The Public Utility Commission of Oregon (OPUC) establishes tariffs and retail revenue requirements based upon the cost to serve retail customers and a fair return on investment, using a forecasted test year and an original cost rate base. Wholesale power and transmission prices are regulated by the Federal Energy Regulatory Commission (FERC). While Oregon law provides for both direct access to competing energy suppliers and market price options, the Company remains obligated to provide service to all of its retail customers, the large majority of which buy electricity at prices determined by the cost of service. Subject to regulatory review and timing, PGE expects the OPUC to recognize all prudently-incurred costs in setting prices, although there can be no assurance that the Company will have an opportunity to fully recover its costs through prices set in the regulatory process. While the OPUC order in PGE's recent general rate case allows the Company to adjust customer prices for changes in forecasted power costs on an annual basis, prices applicable to forecasted non-power costs are adjusted only in a general rate proceeding.

PGE's mission is to be a company that customers and communities depend upon to provide electric service in a safe, responsible and reliable manner, with excellent customer service, at a reasonable price. The Company's stated long-term goals are to achieve and maintain high customer value, provide reliable and reasonably priced power, achieve strong financial performance, attract and retain an engaged and valued workforce, and maintain its tradition of active corporate responsibility.

The continued strength of Oregon's economy has contributed to sustained customer growth and increasing demand for electricity within PGE's service territory. New thermal generation is expected to come on line in late April 2007 to help meet continued load growth and supplement the output of the Company's current generating facilities. In addition, PGE is pursuing its commitment to renewable energy as it plans for new wind generation resources and supports new legislative initiatives that encourage the growth of renewable energy in Oregon. The Company's integrated resource planning process includes consideration and acquisition of a diversified resource portfolio that balances cost, price stability, and overall risk.

In August 2006, the Oregon Supreme Court ruled on the case involving recovery of PGE's investment in Trojan. Although considerable uncertainty remains with respect to this matter, PGE views this as a step toward ultimate resolution. In September, the OPUC issued permanent rules for the implementation of Oregon Senate Bill 408 (SB 408), which adjusts the way that Oregon utilities recover income tax expense from customers; as a result, the Company has recorded a reserve for potential customer refunds. Further discussion of these matters is contained in the "Financial and Operating Outlook" section of this Item 7.

Demolition of major structures at the closed Trojan nuclear power facility is continuing, with implosion of the cooling tower successfully completed in May 2006. Remaining structures, including the plant's containment building, will be removed over the next two years, with demolition work designed to minimize impacts on the environment and surrounding communities.

Ownership of PGE -

The transition of PGE to an independent publicly-owned company occurred in April 2006 with the issuance of new PGE common stock. Following the stock issuance and execution of a separation agreement, PGE is no longer a subsidiary of Enron.

Distribution of new PGE common stock from a Disputed Claims Reserve (DCR) to Enron creditors is continuing, with approximately one-half of the 62.5 million outstanding shares distributed as of February 1, 2007. The new common stock is listed on the New York Stock Exchange under the ticker symbol POR. The

Company's Annual Meeting of Shareholders, its first as a newly-independent company, will be held on May 2, 2007. For further information, see "Ownership of PGE" in "Financial and Operating Outlook" of this Item 7.

Customers -

PGE continues its focus on customer service and recognizes the importance of reliability, restoration response, safety, and reasonable rates in maintaining overall customer satisfaction. The Company continues to effectively maintain and improve its transmission, distribution, and customer service systems to meet regulatory standards for safety and service quality related to outage frequency and duration.

Like most utilities, PGE's business is affected by the general economy and by population growth in its service territory. The Company continues to experience customer growth, adding approximately 57,000 retail customers in the last five years (including 13,000 in 2006), and now serves 793,000 customers as the largest retail supplier of electricity in the state.

Oregon's economy continued to expand in 2006, adding over 135,000 jobs (including 15,000 in manufacturing) during the last three years, continuing its rebound from the 2001-2003 period. Such growth resulted in annual average payroll gains of 2% in 2004, 3.4% in 2005, and 3.1% in 2006. The state's payroll growth in 2006 ranked among the highest of all 50 states and considerably exceeded the 1.4% U.S. growth rate. Oregon's 5.4% average unemployment rate in 2006 was down from 6.2% in 2005 and markedly improved from the high of 8.5% in July 2003. Oregon's non-farm employment (seasonally adjusted) in December 2006 exceeded the previous peak set in November 2000. Continued high energy prices could, however, affect the future growth of both the state and national economy.

PGE's total retail energy deliveries in 2006 increased 3.6% over 2005 as the result of continued customer growth, higher industrial sales, and weather conditions. On a weather adjusted basis, retail energy deliveries increased

2.7% from 2005, with higher energy use by all major customer sectors. On July 24, 2006, the Company recorded a new all-time high net system load "summer peak" of 3,706 MW, also the highest for the year.

PGE offers customers numerous service options under Oregon's 2002 electricity restructuring law. In 2006, non-residential customers with a total average load of approximately 125 MWa (5% of PGE's total retail load) purchased their energy requirements from Electricity Service Suppliers (ESSs). It is currently estimated that customers with a total average load of approximately 270 MWa (11% of PGE's total retail load) will purchase from ESSs in 2007. While these "direct access" customers purchase their electricity from other suppliers, PGE continues to deliver energy to these customers and is not adversely impacted financially. Other options include market-based pricing and renewable resource rates. About 50,000 customers have enrolled in renewable energy programs, with PGE recently recognized by the U.S. Environmental Protection Agency (EPA) and the U.S. Department of Energy (USDOE) as the nation's leader in "green power" consumption by residential customers.

PGE's ongoing maintenance of its transmission and distribution systems, as well as its commitment to customer service and outage preparedness, enabled the Company to effectively restore service to customers that lost power during a severe windstorm in mid-December 2006. The storm was the worst that PGE has experienced in the last decade and affected nearly 250,000 customers throughout the Company's service territory.

PGE is investigating a system-wide advanced metering infrastructure (AMI) network which, if implemented, would serve nearly all of the Company's residential and commercial customers. The AMI project, which is subject to review and approval by the OPUC, is expected to result in support for demand response and direct load control programs, provide new and improved services to customers, and achieve operational efficiencies and cost reductions. PGE will be moving the AMI project through the regulatory process and expects an OPUC decision in the third quarter of 2007. If approved, it is expected that the full project would be completed by the end of 2009 at a total cost of approximately $140 million.

Power Supply -

PGE relies on its thermal and hydroelectric generating resources, as well as wholesale market purchases, to meet its customers' energy needs. PGE's thermal generation portfolio was restored to full strength in the second half of 2006 with the return of the Boardman coal plant to operations on July 1. Regional hydro conditions in 2006 approximated average levels and were significantly improved from the Pacific Northwest's severe to moderate drought conditions of the past three years. Increased stream flows in both the Clackamas and Deschutes river systems, where PGE's hydro facilities are located, resulted in a 28% increase in hydro generation from 2005. Improved regional conditions resulted in a 13% increase in output received from mid-Columbia River hydro projects with which PGE has long-term power purchase contracts, and have also contributed to lower wholesale market prices. Early forecasts indicate near normal hydro conditions in 2007.

PGE continues to implement its current Integrated Resource Plan (IRP) to meet the electricity needs of its growing customer base. The 400 MW Port Westward natural gas-fired plant is expected to go into service in late April 2007 and an agreement has been executed for the purchase of wind turbines for the first phase of the Biglow Canyon Wind Farm (125 MW), expected to be completed by the end of 2007. PGE currently plans to file a new IRP with the OPUC in the second quarter of 2007.

Regulatory bodies are examining the issues of regional haze and mercury in the atmosphere and could require that the Company make modifications to its thermal generating facilities. The EPA and several states, including Oregon and Montana, are expected to tighten controls on mercury emissions, which could have an impact on both the Boardman and Colstrip plants. Although the full impact of future state and federal remediation measures is not yet determinable, it is expected that such measures will increase expenditures for PGE and be included in customer rates.

Regulatory Matters -

On January 12, 2007, the OPUC issued an order in PGE's general rate case approving an overall price increase of 1.3%. The increase represents the combined effect of a 1.4% decrease related to general costs, which became effective on January 17, 2007, and a 2.8% increase related to cost recovery of Port Westward, to become effective when the plant goes into service, expected to be in late April 2007. The decrease related to general costs primarily reflects reductions in forecasted test year costs and the effects of decisions regarding cost of capital. In addition, the OPUC approved a 5.1% price increase to cover higher power costs, as determined under PGE's Resource Valuation Mechanism (RVM), which became effective on January 1, 2007. The OPUC also approved a new Annual Power Cost Update Tariff, with rate adjustments to reflect updated power cost forecasts, and a Power Cost Adjustment Mechanism (PCAM), with rate adjustments reflecting the difference between forecast and actual power costs. The approved change in retail prices is based upon a 50% equity capital structure and a 10.1% return on equity. For further information, see "Resource Valuation Mechanism" and "General Rate Case" in "Financial and Operating Outlook" of this Item 7.

On February 12, 2007, the OPUC issued an order authorizing PGE to defer for future rate recovery $26.4 million of excess power costs related to Boardman's 2005-2006 outage. For further information, see "Boardman Coal Plant - Repair Outages" in "Financial and Operating Outlook" of this Item 7.

SB 408, which adjusts the way that PGE and other Oregon investor-owned utilities recover income tax expense from customers through revenues for utility services, became effective in 2006. Based on PGE's assessment of the OPUC's permanent rules, the Company has established a $42 million reserve (including $2 million of accrued interest) for potential refunds to customers. PGE believes that SB 408 has resulted in some unintended financial impacts and will continue to evaluate its options for changing or modifying the legislation and rules.

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. PGE will continue to operate under annual licenses from the FERC until a new license is issued.

Financial Performance -

Earnings for 2006 were somewhat higher than in 2005 due primarily to non-operating factors. In addition, reserves established for potential customer refunds under SB 408 and the high cost of power to replace the output of Boardman during the plant's outage in the first half of 2006 were only partially offset by the positive results of PGE's operations, resulting from higher energy sales and improved hydro conditions, during the year.

PGE maintains its investment grade bond ratings and stable operating cash flow, with adequate liquidity available through both its $400 million credit facility and access to the commercial paper market. The Company issued $275 million of First Mortgage Bonds in May 2006 and has reached an agreement to issue an additional $170 million of First Mortgage Bonds by June 1, 2007. Such sources, combined with the Company's long-term borrowing capability, provide for continued capital requirements, including investments in the new Port Westward and Biglow Canyon generating facilities.

Following the issuance of new PGE common stock, the Company declared and paid a total of $42 million in dividends in 2006 and early-2007 and currently expects to continue to pay regular quarterly dividends. PGE's objective is to maintain a common equity ratio of approximately 50% in order to maintain acceptable credit ratings and allow access to long-term capital at reasonable rates. PGE's common equity ratio at December 31, 2006 was 53.0%.

Results of Operations

2006 Compared to 2005

PGE's net income in 2006 was $71 million ($1.14 per diluted share) compared to $64 million ($1.02 per diluted share) in 2005. Results for 2005 included a $6 million after tax reserve related to the refund to customers of previously collected local income taxes. In 2006, PGE recorded a $26 million after tax reserve for a potential refund obligation to customers, reflecting the Company's current estimate of the impact of SB 408. The Company also incurred $46 million in incremental replacement power costs in 2006 (compared to $40 million in 2005) related to the extended, unplanned outage at the Boardman coal plant, resulting in a $4 million after tax decrease in earnings. PGE also incurred higher distribution expenses in 2006, including those related to winter storm restoration. The SB 408 reserve, higher Boardman replacement power costs, and increased distribution expenses were partially offset by the combined effect of higher energy sales, resulting from both an increase in customers served and weather conditions, and increased hydro availability, resulting from improved stream flows.

The following tables summarize Operating Revenues and Energy sold and delivered for 2006 and 2005:

		2006	
Operating revenues (millions)			
Retail sales			
Residential	$	628	
Commercial		547	
		206	

Industrial		
Total retail sales		1,381
Direct access customers		
Commercial		(6)
Industrial		(6)
Tariff revenues		1,369
Accrued revenues		38
Provision for refund - SB 408		(40)
Total retail revenues		1,367
Wholesale revenues (non-trading)		135
Other operating revenues		18
Total Operating Revenues	$	1,520

	2006
Energy sold and delivered - MWhs (000's)	
Retail energy sales	
Residential	7,573
Commercial	7,319
Industrial	3,541

Total retail energy sales	18,433
Delivery to direct access customers	
Commercial	430
Industrial	569
Total retail energy deliveries	19,432
Wholesale sales (non-trading)	3,312
Trading activities	-
Total energy sold and delivered	22,744
Customers - end of period	
Residential	696,779
Commercial	95,734
Industrial	259
Total retail customers	792,772

Total Operating Revenues increased about 5% from 2005 due to increases in both Retail and Wholesale Revenues. The increase in Retail Revenues resulted from both higher energy sales and a 2006 rate increase related to higher power costs. (See "Resource Valuation Mechanism" in "Financial and Operating Outlook" of this Item 7 for further information). Partially offsetting these increases was a $40 million pre-tax reserve for a potential refund obligation to customers related to the Company's current estimates of the impact of SB 408. (See "Utility Rate

Treatment of Income Taxes" in the "Financial and Operating Outlook" of this Item 7 for further information). In addition, there was a $26 million reduction in the collection of regulatory assets (fully offset within Net Operating Income due to a corresponding decrease in Depreciation and Amortization expense). The reduction in Direct Access Customer Revenues resulted from "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.

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February, March, and October, along with significantly warmer weather in June and September, also contributed to higher energy use.

Wholesale revenues increased 16% in 2006 due to higher wholesale energy sales that resulted from favorable hydro generation conditions and excess wholesale power purchases. This quantity increase was partially offset by lower average spot market prices that resulted primarily from increased regional hydro generation.

The decrease in Other Operating Revenues from last year was primarily the result of current year losses from the sale of natural gas in excess of generating plant requirements.

Purchased Power and Fuel expense for 2006 increased $92 million (14%) from 2005. The increase was due to higher power purchases required to meet a 10% increase in total system load requirements, an increase in the cost of replacing coal-fired generation at Boardman, and higher wholesale prices. Approximately $52 million and $40 million of incremental power costs were incurred in 2006 and 2005, respectively, to replace the output of Boardman, which was taken out of service in late October 2005 for repair of the plant's turbine rotor and which remained out of service for most of the first half of 2006 for additional repairs, including those to the plant's generator rotor. Partially offsetting incremental replacement power costs in 2006 was the deferral, for later ratemaking treatment, of $6 million related to the Boardman outage. (See "Boardman Coal Plant - Repair Outages" in "Financial and Operating Outlook" of this Item 7 for further information). The above cost increases were partially offset by the effect of improved regional hydro conditions.

Company generation decreased about 8% from 2005, with reduced thermal generation (related primarily to Boardman's outage) partially offset by a 28% increase in PGE hydro production, resulting from increased stream flows. Total generation met approximately 37% of PGE's retail load in 2006, compared to 42% in 2005. Production from PGE's hydro plants met approximately 10% of total retail load requirements, compared to 8% in 2005, while output received under long-term power purchase contracts from mid-Columbia River hydro projects met approximately 14% of total retail load, compared to 15% in 2005.

The following table indicates PGE's total system load (including both retail and wholesale) for the last two years. Average variable power costs include wheeling and exclude unrealized gains and losses from derivative instruments.

Megawatt-Hours/Variable Power Costs	
Megawatt-Hours (thousands)	Averag Power Cost

	2006	2005	2006
Generation	7,209	7,821	13.8
Term Purchases	13,582	11,705	40.8
Spot Purchases	2,229	1,361	25.1
Total System Load	23,020	20,887	33.6

Production, distribution, administrative and other expenses increased $8 million (3%) from 2005. Higher expenses in 2006 resulted from maintenance and repair activities at PGE's thermal generating plants, storm-related service restoration costs, and increased tree trimming costs. A decrease in administrative and other expenses was largely the result of the settlement of certain asserted claims in 2005. Depreciation and Amortization expense decreased $14 million (6%), as a $26 million decrease in the amortization of regulatory assets (fully offset within Net Operating Income due to a corresponding decrease in Operating Revenues) was partially offset by increased depreciation of transmission and distribution plant.

Income taxes decreased $8 million due primarily to lower taxable income and a reduction in state income taxes resulting from apportionment rule changes.

Other Income (Miscellaneous) increased $6 million, related primarily to the establishment, in 2005, of a $10 million reserve for the refund to Multnomah County customers of previously collected income taxes. (See "Class Action Lawsuit - Multnomah County Business Income Taxes" in the "Financial and Operating Outlook" of this Item 7 for further information). Partially offsetting this increase was a $3 million decrease in interest income on regulatory assets, due to declining balances as amounts are recovered from customers. The $8 million increase in Allowance for equity funds used during construction was related primarily to Port Westward.

2005 Compared to 2004

PGE's net income in 2005 was $64 million compared to $92 million in 2004. The decrease was due primarily to reduced margins on energy sales, caused by replacement power costs for the extended, unplanned outage at the Boardman coal plant for repair of the plant's turbine rotor. In addition, results for 2005 were adversely affected by higher administrative and general expenses (including the settlement of certain asserted claims), a reserve for the refund to customers of previously collected local income taxes, and higher expenses related to preventive maintenance of the Company's distribution facilities.

The following tables summarize Operating Revenues and Energy sold and delivered for 2005 and 2004:

	2005	
Operating revenues (millions)		
Retail sales		
Residential	$	593
Commercial		505
Industrial		178
Total retail sales		1,276
Direct access customers		
Commercial		1
Industrial		-

Tariff revenues		1,277
Accrued revenues		28
Total retail revenues		1,305
Wholesale revenues (non-trading)		116
Other operating revenues		
Trading activities - net		-
Other		25
Total Operating Revenues	$	1,446
Energy sold and delivered - MWhs (000's)		
Retail energy sales		
Residential		7,323
Commercial		7,069
Industrial		3,148
Total retail energy sales		17,540
Delivery to direct access customers		
Commercial		400
Industrial		814
Total retail energy deliveries		18,754
Wholesale sales (non-trading)		2,094
Trading activities		815

Total energy sold and delivered		21,663
Customers - end of period		
Residential		685,568
Commercial		94,012
Industrial		257
Total retail customers		779,837

Total Retail Revenues decreased about 1% from 2004. A decrease in energy sales and a $23 million reduction in amounts recovered from customers related to power cost adjustment mechanisms in effect in 2001 and 2002 (fully offset within Purchased Power and Fuel expense) were partially offset by a 1.4% average rate increase for 2005. (For further information, see "Resource Valuation Mechanism" in "Financial and Operating Outlook" of this Item 7). The decrease in Direct Access Customer Revenues, consisting of service charges for electricity delivered to customers who purchase energy requirements from ESSs, was attributable to "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. Total Retail Energy Sales decreased 1%, with declines in both commercial and industrial usage partially offset by increased residential use resulting from colder weather in the fourth quarter of 2005 and an approximate 11,000 increase in customers served. Declines in commercial and industrial energy sales of 2.5% and 3.1%, respectively, were largely related to customers who chose to purchase their energy requirements from ESSs beginning in 2005. PGE continues to deliver energy to these customers, with about one-third of the increase in Total Retail Energy Deliveries in 2005 attributable to a single large industrial customer.

Wholesale revenues increased by about 8% in 2005 due primarily to a 32% increase in average price, driven largely by higher natural gas prices. This was partially offset by an approximate 18% reduction in wholesale electricity sales resulting from reduced market activity.

The decrease in Other Operating Revenues from last year was caused primarily by reduced margins on the sale of natural gas in excess of plant requirements.

Purchased Power and Fuel expense for 2005 increased $4 million (1%) from 2004. An 11% increase in PGE's average variable power cost was largely offset by both a reduction in total system load and a $24 million decrease related to the amortization of costs deferred under power cost adjustment mechanisms in effect during 2001 and 2002, which were later recovered from customers (fully offset within Retail revenues). The increase in average variable power cost was caused primarily by approximately $40 million of incremental power costs incurred to replace coal-fired generation at Boardman, which was taken out of service in mid-October 2005 for removal and repair of the plant's turbine rotor. Lower hydro production in 2005 (due to low stream flows) also contributed to the year's higher average variable power cost. Such cost increases were partially offset by higher unrealized gains from derivative instruments. Company generation decreased about 4% from 2004, with 17% and 9% reductions, respectively, in combustion turbine and hydro production partially offset by increased coal-fired generation, primarily from Colstrip. Total generation met approximately 42% of PGE's retail load in 2005, compared to 43% in 2004.

The following table indicates PGE's total system load (including both retail and wholesale) for the last two years. Average variable power costs include wheeling and exclude unrealized gains and losses from derivative instruments and the effect of credits to purchased power and fuel costs related to PGE's power cost adjustment mechanisms, as discussed above.

Megawatt-Hours/Variable Power Costs

Megawatt-Hours (thousands)		Averag Power Cos
2005	2004	2005

Generation	7,821	8,114	13.7
Term Purchases	11,705	12,017	35.3
Spot Purchases	1,361	1,343	57.4
Total System Load	20,887	21,474	31.3

Production, distribution, administrative and other expenses increased $21 million (8%) from 2004 due primarily to increased employee benefit expenses (including medical and pension costs), the settlement of certain asserted claims, and an increase in distribution and preventive maintenance expenses. These were partially offset by a reduction in maintenance and other expenses at the Company's thermal generating plants.

Income taxes related to utility operations decreased $11 million primarily due to lower pre-tax operating income.

Other Income (Miscellaneous) decreased $5 million due primarily to the establishment of a $10 million reserve related to the future refund to Multnomah County customers of previously-collected income taxes, pursuant to a settlement agreement. For further information, see "Class Action Lawsuit - Multnomah County Business Income Taxes" in "Financial and Operating Outlook" of this Item 7.

Capital Resources and Liquidity

Review of Cash Flow Statement

Cash Provided by Operations

is used to meet the day-to-day cash requirements of PGE. Supplemental cash is obtained from external borrowings, as needed.

A significant portion of cash from operations consists of charges that are recovered in customer revenues for depreciation and amortization of utility plant that require no current period cash outlay. The recovery from customers of prior capital expenditures through depreciation and amortization provides a source of funding for current and future cash requirements. Cash flows from operations can also be affected by changes in the price of power and fuel as well as by weather conditions, as temperatures outside the normal range can affect electricity usage and resultant cash flow.

Cash provided by operating activities totaled $106 million in 2006 compared to $372 million provided by operating activities in 2005. The decrease was due primarily to a $119 million increase in power and fuel purchases and a $129 net decrease in cash collateral deposits received from certain wholesale customers. In addition, there was a $13 million increase in income tax payments and a $10 million refund of business income taxes to customers in Multnomah County, pursuant to a settlement agreement.

Investing Activities

consist of new construction and improvements to PGE's distribution, transmission, and generation facilities. The $116 million increase in capital expenditures in 2006 is primarily due to construction costs of Port Westward and initial costs related to the Biglow Canyon Wind Farm. Other expenditures were related to the expansion of PGE's distribution system to support both new and existing customers within the Company's service territory.

Financing Activities

provide supplemental cash for both day-to-day operations and capital requirements as needed. PGE relies on cash from operations, the issuance of commercial paper, borrowings under its revolving credit facility, and long-term financing activities to support such requirements.

In May 2006, PGE issued $275 million of First Mortgage Bonds, consisting of two series. One series, in the amount of $175 million, bears interest at an annual rate of 6.31% and will mature in 2036. The other series, in the amount of $100 million, bears interest at an annual rate of 6.26% and will mature in 2031. PGE used the proceeds from the bond issuances for the early retirement of the $150 million principal amount of 8 1/8% Series First Mortgage Bonds due in 2010, and for general corporate purposes. PGE also repaid $9 million of conservation bonds and retired $3 million of preferred stock during 2006.

PGE issued $81 million in short-term debt in 2006 and also paid cash dividends totaling $28 million on its common stock during the year. In 2005, PGE paid a common stock dividend of $150 million to Enron.

The issuance of additional First Mortgage Bonds and preferred stock requires PGE to meet earnings coverage and security provisions set forth in the Company's Articles of Incorporation and the Indenture of Mortgage and Deed of Trust securing the bonds. PGE estimates that on December 31, 2006 it could issue up to approximately $517 million of First Mortgage Bonds under the most restrictive issuance test in the mortgage. In addition, it is estimated that the Company could issue up to approximately $242 million in preferred stock under the restrictions set forth in the Articles of Incorporation. Any issuances would also 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 mortgage on the basis of property additions, bond credits, and/or deposits of cash. Based on the availability of the short-term credit facility and the expected ability to issue long-term debt and equity securities, management believes there is sufficient liquidity to meet the Company's anticipated capital and operating requirements.

PGE has a $400 million five-year revolving credit facility with a group of commercial banks. The facility, which is unsecured, is used as backup for commercial paper borrowings and is available for general corporate purposes, with the maximum amount available to PGE for borrowings and/or the issuance of standby letters of credit. At December 31, 2006, PGE had $81 million of short-term commercial paper outstanding and had utilized approximately $6 million in letters of credit ($2 million related to wholesale trading activities and $4 million related to Port Westward), with approximately $313 million available for additional borrowings and/or letters of credit.

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 facility. A provision of the facility allows PGE to annually request that the termination date be extended for one additional year. Any request requires approval of a majority of the participating banks, with the termination date extended only for those banks approving the request. In July 2006, upon approval of all participating banks, the facility was amended to extend the termination date to July 14, 2011. The facility provides that all outstanding loans mature on the termination date of the facility. The facility requires annual fees based on PGE's unsecured credit ratings, and contains customary covenants and default provisions, including a requirement that limits consolidated indebtedness, as defined in the facility, to 65% of total capitalization. At December 31, 2006, the Company's consolidated indebtedness to total capitalization ratio, as calculated under the facility, was 46.3%.

PGE has authorization from the FERC to issue short-term debt, in an amount not to exceed $400 million outstanding at any one time, over the two-year period February 8, 2006 through February 7, 2008.

Cash Requirements

Access to short-term debt markets provides necessary liquidity to support PGE's current operating activities, including the purchase of electricity and fuel. Long-term capital requirements are driven largely by debt refinancing activities and capital expenditures for distribution, transmission, and generation facilities to support both new and existing customers.

PGE's liquidity and capital requirements can be significantly affected by operating costs, capital expenditures, debt service, and working capital needs, including margin deposits related to wholesale trading activity. PGE's revolving credit facility supplements operating cash flow and provides a primary source of liquidity. PGE's ability to secure sufficient long-term capital at reasonable cost is determined by its financial performance and outlook, capital expenditure requirements (including the effects of these factors on the Company's credit ratings), and alternatives available to investors. The Company's ability to obtain and renew such financing depends on its credit ratings as well as on bank credit markets, both generally and for electric utilities in particular.

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. PGE's objective is 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 53.0% and 57.5% at December 31, 2006 and December 31, 2005, respectively.

As previously indicated, a significant portion of cash provided by operations consists of depreciation and amortization of utility plant which is recovered in rates. PGE estimates recovery of such charges to approximate $180 million to $190 million annually over the period 2007-2009. Combined with all other sources, cash provided by operations is estimated to range from $280 million to $320 million annually during the 2007-2009 period.

The following table indicates PGE's projected primary cash requirements for the years indicated (in millions):

	2007	2008
Capital expenditures (*)	$430 - $450	$250 - $270
Long-term debt maturities	$66	-

(*) Includes expenditures related to Phase I of the Biglow Canyon Wind Farm (approximately $200 million for 2007), the construction of Port Westward (approximately $12 million for 2007), and fish passage measures at the Pelton Round Butte hydroelectric project (approximately $47 million for 2007 - 2009). Excludes expenditures related to the advanced metering infrastructure project, which remains subject to regulatory approval.

PGE's revolving credit facility may be used to fund any potential cash shortfall, with additional liquidity available, if necessary, from the issuance of long-term debt. In December 2006, the Company entered into an agreement with certain institutional buyers to issue $170 million of PGE's First Mortgage Bonds by June 1, 2007. (For additional information, see Note 7, Credit Facility and Debt, in the Notes to Financial Statements).

Cash balances are temporarily invested primarily in government money market funds and short-term commercial paper that have remaining maturities of less than three months from the date of acquisition. Such investments, which are considered cash equivalents, are consistent with PGE's investment objectives to preserve principal, maintain liquidity, and diversify risk, and are limited to investment grade securities (primarily short term).

Following the issuance of new PGE common stock, the Company paid a total of $28 million in dividends in 2006. In addition, the PGE Board of Directors on October 26, 2006 declared a quarterly common stock dividend of 22.5 cents per share that was paid on January 15, 2007. The Company expects to pay regular quarterly dividends on its common stock; however, the declaration of such dividends is at the discretion of the Company's Board of Directors and is not guaranteed. The amount of common dividends will depend upon PGE's results of operations and financial condition, future capital expenditures and investments, any applicable regulatory and contractual restrictions, and other factors that the Board of Directors considers relevant.

The OPUC order approving the issuance of new PGE common stock includes a stipulation containing several conditions, including a requirement that, after issuance of the new common stock, PGE cannot pay a dividend that would reduce the Company's common equity capital percentage below 48% of total capitalization (excluding short-term borrowings) without prior OPUC approval. The requirement is reduced to 45% when the DCR holds between 20% and 40% of the issued and outstanding common stock of PGE, with no minimum common equity capital percentage requirement when the DCR holds less than 20% of the issued and outstanding common stock of PGE. At February 1, 2007, the DCR held approximately 51% of the total outstanding common stock of PGE. Other conditions include a requirement that the OPUC be notified (simultaneously with the public) of any dividend declared by PGE's Board of Directors. Management believes that, at December 31, 2006, the Company has the ability to pay dividends, notwithstanding the above restrictions.

Credit Ratings

PGE's secured and unsecured debt are rated at investment grade by Moody's Investors Service (Moody's) and Standard and Poor's (S&P).

PGE's current credit ratings are as follows:

	Moody's
First Mortgage Bonds	Baa1
Senior unsecured debt	Baa2
Preferred stock	Ba1
Commercial paper	Prime-2

Outlook:	Stable

On November 10, 2006, Fitch Ratings affirmed PGE's existing ratings and announced that they would no longer provide ratings coverage for the Company. On January 29, 2007, S&P reaffirmed PGE's current credit ratings and outlook.

Should Moody's or S&P (or both) reduce the credit rating on PGE's unsecured debt to below investment grade, the Company could be subject to requests by certain of its wholesale counterparties to post additional performance assurance collateral. On January 31, 2007, PGE had posted approximately $26 million of collateral, consisting of $2 million in letters of credit and $24 million in cash. Based on the Company's non-trading portfolio, estimates of current energy market prices, and the current level of collateral outstanding, as of January 31, 2007, the approximate amount of additional collateral that could be requested upon a single agency downgrade event to below investment grade is approximately $57 million and decreases to approximately $8 million by year-end 2007. The approximate amount of additional collateral that could be requested upon a dual agency downgrade event to below investment grade is approximately $73 million and decreases to approximately $10 million by year-end 2007.

In addition to collateral calls, a credit rating reduction could impact the terms and conditions of long-term debt issued in the future. Any rating reductions could also increase interest rates and fees on PGE's revolving credit facility, increasing the cost of funding the Company's day-to-day working capital requirements. PGE's financing arrangements do not contain ratings triggers that would result in an acceleration of the required interest and principal payments in the event of a ratings downgrade. Management believes that the Company's existing line of credit, access to the commercial paper market, and cash from operations provide it with sufficient liquidity to meet its day-to-day cash requirements.

Contractual Obligations and Commercial Commitments

The following indicates PGE's contractual obligations as of December 31, 2006 (in millions):

	P					
		Total		2007		2008
Long-Term Debt	$	1,003	$	66	$	-
Short-Term Debt		81		81		-
Interest on Long-Term Debt		973		61		59
Operating Leases		265		8		8
Purchase Obligations		263		221		34
Purchased Power and Fuel:						
Electricity Purchases		1,736		665		214
Capacity Contracts		210		23		23
Natural Gas Agreements		181		34		21
Public Utility Districts		94		8		8
Coal and Transportation Agreements		47		13		14

Total		$	4,853		$	1,180		$	381

(*) Future interest on long-term debt is calculated based on the assumption that all debt is outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect at December 31, 2006. Contributions to the Company's pension plan are estimated at zero for 2007 through 2011 and not determinable thereafter. Purchase Obligations in 2007 includes $150 million related to the Biglow Canyon Wind Farm.

Other Financial Obligations

PGE has entered into long-term power purchase contracts with certain public utility districts in the state of Washington under which PGE 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 of 7% of the total project.

For details of annual costs by project, including debt service, see Note 9, Commitments and Guarantee, in the Notes to the Financial Statements.

Off-Balance Sheet Arrangements

PGE is not engaged in any off-balance sheet arrangements through unconsolidated limited purpose entities.

Critical Accounting Policies and Estimates

A critical accounting policy is one that is both important to results of operations and financial condition and requires management to make critical accounting estimates. An accounting estimate is an approximation made by management of a financial statement component or account. Accounting estimates reflected in PGE's financial statements measure the effects of past business transactions or events, or the present status of an asset or liability. Accounting estimates included in the accounting policies described below require assumptions about matters that are highly uncertain at the time the estimate is made. Additionally, different estimates that could have been used, or changes in an accounting estimate that are reasonably likely to occur, could have a material impact on the financial statements. The inherent uncertainty of some matters can make judgments subjective and complex. The effects of estimates and assumptions related to future events cannot be made with certainty. PGE's estimates are based upon historical experience and on assumptions that management believes to be reasonable in the circumstances. These estimates may change with changes in events, information, experience, and the Company's operating environment. The following critical accounting policies and estimates are those used in the preparation of PGE's consolidated financial statements.

Regulatory Accounting

As a regulated utility, PGE prepares its consolidated financial statements in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, Accounting for the Effects of Certain Types of Regulation. In order to apply the accounting policies and practices of SFAS No. 71, regulated companies must satisfy the following conditions: (i) rates are established by or subject to approval by an independent regulator; (ii) rates are designed to recover specific costs of delivering service; and (iii) in view of demand for service, it is reasonable to assume that rates can be charged and collected from customers at levels that will recover the Company's costs. SFAS No. 71 requires companies that meet these conditions to reflect the impact of regulatory decisions in their consolidated financial statements and requires that certain costs be deferred as regulatory assets until matching revenues are recognized. Similarly, certain items may be deferred as regulatory liabilities and amortized to the income statement as rates to customers are reduced.

PGE continues to meet each of above conditions for continued application of SFAS No. 71 in its financial statements. The Company is subject to jurisdiction of the OPUC, which approves PGE's retail rates, ensuring that they provide an opportunity for the Company 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.

PGE's retail operations are conducted within a state-approved service area in which there is no retail competition, other than that related to the state's customer choice program. Participation in this program, implemented in 2002, has not had a material impact on PGE's regulated operations, with only about 5% of the Company's total retail load served by ESSs. The large majority of PGE's customers continue to take service under rate tariffs determined by the cost of service. Changes in demand and level of competition for PGE's regulated services have not materially impacted the Company's ability to recover its costs through regulation.

PGE periodically assesses the continued applicability of SFAS No. 71 to its business, considering both the current and anticipated future rate environment and related accounting guidance, as outlined in SFAS No. 101, Regulated Enterprises - Accounting for the Discontinuation of Application of SFAS No. 71, and Emerging Issues Task Force Issue 97-4, Deregulation of the Pricing of Electricity - Issues Related to the Application of SFAS No. 71 and SFAS No. 101.

As PGE continues to fully meet each of the required conditions, the Company has recorded regulatory assets and liabilities to reflect their expected full recovery or refund in customer rates.

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

Asset Retirement Obligations

SFAS No. 143, as interpreted by FASB Interpretation No. 47, 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 Utility plant are included in Depreciation and Amortization expense, with those related to Other property included in Other Income (Deductions). In accordance with requirements of SFAS No. 143, 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.

Trojan Decommissioning

In early 1993, PGE ceased commercial operation of Trojan and began the decommissioning process. The original Trojan decommissioning cost estimate was prepared by an engineering firm with subsequent updates by PGE, due primarily to the effects of inflation and the timing of certain activities. The net estimated liability for Trojan decommissioning costs as of December 31, 2006 was $108 million, measured at estimated fair value pursuant to provisions of SFAS No. 143. PGE's retail prices, as authorized by the OPUC in January 2007, include recovery of $4.65 million annually. These amounts are deposited in an external trust fund, which reimburses PGE for costs expended under the decommissioning plan. Decommissioning cost estimates include equipment removal, embedded pipe remediation, surface decontamination, non-radiological decontamination, and on-site spent nuclear fuel storage until permanent storage is provided by the USDOE. Estimating the cost of decommissioning activities over a period extending to 2031 is inherently subjective and complex. Such estimates may vary because of changes in regulatory requirements, technology, labor and material costs, and waste burial. In addition, timing of actual activities may differ from that established in the decommissioning plan, which may also cause actual costs to vary from those estimated. Remaining decommissioning activities consist of demolition of the existing structures and long-term operation and decommissioning of the Independent Spent Fuel Storage Installation.

Management does not expect actual future decommissioning costs to change significantly from the current estimate. However, if actual costs significantly exceed the previously estimated amount, funds collected through rates may not be adequate to cover actual decommissioning costs and may require that PGE utilize available cash and a credit facility to advance funds to the trust to cover any near term shortfall. Recovery of any such shortfall from customers would require OPUC approval.

Loss Contingency Reserves

Contingencies are evaluated based on SFAS No. 5, Accounting for Contingencies, using the best information available. A material loss contingency is accrued and disclosed when it is probable that an asset has been impaired or a liability incurred and the amount of the loss can be reasonably estimated. If a range of 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 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.

Receivables and Refunds - California Wholesale Market

As of December 31, 2006, PGE has net accounts receivable balances totaling approximately $63 million for wholesale electricity sales made to the California Independent System Operator (ISO) and the California Power Exchange (PX) from November 2000 through February 2001. The Company estimates that the majority of this amount was for sales by the ISO and PX to Southern California Edison Company and Pacific Gas & Electric Company. In 2001, the PX filed for bankruptcy and Pacific Gas & Electric Company filed a voluntary petition for relief under the provisions of Chapter 11 of the federal Bankruptcy Code. Although both entities have emerged from their bankruptcy proceedings as reorganized debtors, not all claims filed in the proceedings, including those filed by PGE, have been resolved.

In 2002, the FERC ordered refunds for non federally-mandated transactions made between October 2, 2000 and June 20, 2001 in the spot markets operated by the ISO and PX. A methodology to calculate such refunds was also established by the FERC. The FERC has indicated that any potential refunds can be offset by accounts receivable, thereby mitigating the effect of potential refunds on PGE. Calculated interest on potential refunds will likewise be offset by interest on accounts receivable.

The FERC methodology for calculating potential refunds, initially established in July 2001, was revised in March 2003, significantly increasing the refund amount initially estimated. Accordingly, a $17.5 million reserve established at December 31, 2002 was increased to $40 million at December 31, 2003. Pursuant to FERC guidelines, PGE in September 2005 filed a cost recovery study to prove that the Company, in order to cover its costs, should be permitted to recover additional revenues in excess of the mitigated prices. By order issued November 2, 2006, the FERC accepted, subject to PGE making certain additional revisions, a revised cost recovery study that had been filed by PGE in response to an earlier January 26, 2006 order. Pursuant to the November 2, 2006 order, PGE filed a final cost study with the ISO that now reflects an approximate $19.8 million cost offset to its refund obligation. Third parties have challenged PGE's cost recovery filings and made numerous requests that they be rejected in their entirety or that the cost offset be reduced to zero. PGE has filed responses to those challenges.

PGE believes that the FERC erred in certain findings in its orders regarding PGE's cost recovery, and has filed requests for rehearing as to several issues in those orders. Due to the continuing uncertainty related to these matters, PGE has made no adjustment to the $40 million reserve previously established for the Company's potential liability. As an unresolved legal and regulatory matter, both the refund methodology and estimated amount may vary significantly in the future, which could have a material impact on PGE's results of operations.

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 under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended.

In its January 2007 general rate order, the OPUC approved a new PCAM by which PGE can adjust future rates to reflect the difference between each year's forecasted and actual net variable power costs on a settlement basis. Effective December 2006, PGE began to apply SFAS No. 71 to all derivative instruments to reflect the effects of regulation. As a result, a regulatory asset or regulatory liability is recorded to offset changes in fair value of instruments not included in the Resource Valuation Mechanism (RVM). Prior to December 2006, changes in fair value for these instruments were not offset by a regulatory asset or regulatory liability unless those contracts were previously included in rates under the RVM or were expected to be included in future rates under the RVM. Effective January 17, 2007, a new Annual Power Cost Update Tariff replaced the RVM. For further information, see "Resource Valuation Mechanism" and "General Rate Case" in "Financial and Operating Outlook" of this Item 7.

Mark-to-Market

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 is the difference between the premium paid or received and 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 could have a material impact on PGE's financial condition and results of operations.

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. At December 31, 2006, the plan's assets were comprised of approximately 67% equity securities and 33% debt securities.

Changes in actuarial assumptions can also materially affect net periodic pension expense. A 0.25% reduction in the expected long-term rate of return on plan assets would have increased 2006 pension expense by approximately $1.2 million. A 0.25% reduction in the discount rate would have increased 2006 pension expense by approximately $1.6 million.

Utility Rate Treatment of Income Taxes

In 2005, the State of Oregon adopted SB 408, a law that adjusts the way that PGE and other Oregon investor-owned electric and gas utilities recover income tax expense from customers through revenues for utility services. The law authorizes an adjustment to retail customer rates based on the difference between "taxes authorized to be collected" and "taxes paid" to governmental entities on or after January 1, 2006. In September 2006, the OPUC adopted permanent rules to implement SB 408. As a result of its assessment of the rules, PGE has estimated potential refunds to customers of approximately $42 million for 2006, including $2 million of accrued interest. PGE will continue to evaluate its options for changing or modifying the legislation and rules, and challenging any adjustment that follows for the 2006 tax year. For further information, see "Utility Rate Treatment of Income Taxes" in "Financial and Operating Outlook" of this Item 7.

Transactions with Related Parties

PGE services to affiliated companies consist primarily of employee and administrative services. Transactions with affiliated companies are subject to regulation by the OPUC. Most affiliated interest transactions are made under a

Master Service Agreement filed with the OPUC. Under OPUC regulations, services provided to affiliates by PGE are charged at the higher of cost or market, while affiliated services received by PGE are charged at the lower of cost or market. Services with affiliated companies in 2006 were not material.

Financial and Operating Outlook

Retail Customer Growth and Energy Deliveries

Weather adjusted retail energy deliveries to PGE and ESS customers increased 2.7% in 2006 compared to 2005, with deliveries to residential, commercial, and industrial customers increasing by 2.4%, 3.0%, and 2.6%, respectively. The increase for residential customers resulted primarily from an 11,800 increase in the average number of customers served during the year. The increase for commercial and industrial customers resulted from a 1,700 increase in customers served, higher average use, and an improved economy. PGE forecasts total weather adjusted energy deliveries to PGE and ESS customers to increase by approximately 1.2% in 2007.

Power and Fuel Supply

Wholesale power market products, along with PGE's base of thermal and hydroelectric generating capacity, currently provide the Company the flexibility to respond to seasonal fluctuations in the demand for electricity from its retail and wholesale customers. Although surplus generation has diminished in recent years due to economic and population growth in the western United States, the recent construction of new generating plants has increased the region's capacity to meet its power needs. The Company anticipates that an active wholesale market and generating capacity within the Western Electricity Coordinating Council will provide wholesale energy to supplement its generation and purchases under existing firm power contracts.

Early forecasts indicate that regional hydro conditions will be near normal in 2007. Volumetric water supply forecasts for the Pacific

Northwest (as of February 15, 2007), prepared by the Northwest River Forecast Center in conjunction with the Natural Resources Conservation Service and other cooperating agencies, indicate the projected January-to-September 2007 runoff (as measured at The Dalles, Oregon) at 94% of normal, compared to actual runoffs of 107% in 2006 and 74% in 2005. In 2007, hydro conditions in both the Clackamas and Deschutes river systems, where PGE's hydro facilities are located, are currently projected to be 97% and 98% of normal, respectively, compared to actual runoffs of 92% and 100% of normal, respectively, in 2006 and 72% and 87% of normal, respectively, in 2005.

PGE generated 37% of its retail load requirement in 2006, with 27% met with thermal generation and the remainder met with hydro generation. Short- and long-term purchases were utilized to meet the remaining load. PGE's ability to purchase power in the wholesale market, along with the Company's base of thermal and hydroelectric generating capacity, currently provides the flexibility to respond to seasonal fluctuations in the demand for electricity both within its service territory and from its wholesale customers.

Factors that can affect the availability and price of purchased power and fuel include weather conditions in the Northwest and Southwest, the performance of major generating facilities in both regions, regional hydro conditions, and prices of natural gas and coal used to fuel thermal generating plants. Market prices of natural gas can also be affected by destructive storms and extreme weather in other sections of the United States and Canada. Power and natural gas prices have moderated since late 2005, due primarily to increased hydro availability within the region and a relatively quiet hurricane season in the Gulf of Mexico, in contrast to 2005.

Price Risk Management -

As PGE's primary business is to serve its retail customers, it uses derivative instruments to manage its exposure to commodity price risk and to minimize net power costs to serve customers. Under SFAS No. 133, as amended, PGE records unrealized gains and losses in earnings in the current period for derivative instruments that do not qualify for either the normal purchases and normal sales exception or cash flow hedge accounting. Derivative instruments that qualify for the normal purchases and normal sales exception are recorded in earnings on a settlement basis, and cash flow hedges are recorded in Other Comprehensive Income (OCI) until they can offset the related results on the hedged item in the income statement. The timing difference between the recognition of unrealized gains and losses on certain derivative instruments (see discussion of RVM and PCAM below) 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 No. 71.

From the time prices were set in the RVM process until the January 16, 2007 end of the RVM period, any changes to electricity and natural gas prices used in the RVM resulted in unrealized gains and losses that were recorded in earnings for existing and new derivative instruments that did not qualify for the normal purchases and normal sales exception or cash flow hedges. As a result, this timing difference created earnings volatility between reporting periods. The earnings volatility has been reduced with the adoption of a PCAM by the OPUC.

In its January 2007 general rate order, the OPUC approved a new PCAM by which PGE can adjust future rates to reflect the difference between each year's forecasted and actual net variable power costs on a settlement basis. Effective December 2006, PGE began to apply SFAS No. 71 to all derivative instruments to reflect the effects of regulation. Prior to December 2006, changes in the fair value of instruments not included in the RVM were not offset by a regulatory asset or regulatory liability.

In 2006, PGE adopted a "medium term" power cost strategy to better respond to changing energy market conditions. By extending the period in which the Company may take positions in power and fuel markets from 24 months to up to five years, PGE expects to reduce price volatility for its customers during the next three- to five-year period. Accordingly, PGE has amended its risk limits for the projected impact of the medium term strategy on the Company's net open position.

Ownership of PGE

In accordance with Enron's Chapter 11 Plan, on April 3, 2006, PGE issued 62.5 million shares (of 80 million, no par value, shares authorized) of new PGE common stock. Approximately 27 million shares of the new PGE common stock were initially issued to the Debtors' creditors holding allowed claims, and approximately 35.5 million shares were issued to the DCR, where the shares will be held to be released over time to the Debtors' creditors holding allowed claims, in accordance with the Chapter 11 Plan. Since the initial distribution, approximately 3.5 million shares of PGE common stock have been released from the DCR, with approximately 32 million shares held in the DCR as of February 1, 2007. The 42.8 million shares of PGE common stock previously held by Enron were cancelled. Following issuance of the new PGE common stock, PGE ceased to be a subsidiary of Enron. The new PGE common stock is listed on the New York Stock Exchange under the ticker symbol POR.

The registered owner of the new PGE common stock held in the DCR is the Disbursing Agent associated with the DCR. The Disbursing Agent oversees the release of new PGE common stock from the DCR to the Debtors' creditors that hold allowed claims. All shares of new PGE common stock held in the DCR will be voted by the Disbursing Agent at the direction of the Disputed Claims Reserve Overseers, which is currently comprised of those individuals who serve on Enron's Board of Directors.

The OPUC order approving the distribution of the new PGE common stock includes 17 conditions that relate to, among other things: certain service quality measures; additional direct access options for commercial and industrial customers; maintenance of PGE's financial strength during the conclusion of the Enron bankruptcy process; and certain indemnifications for PGE from Enron related to Enron-sponsored employee benefit plans and certain liabilities related to taxes that may be imposed as the result of PGE's inclusion in Enron's consolidated tax group. These indemnifications are included in the separation agreement described below.

On February 10, 2006, the City of Portland appealed the OPUC order approving the distribution of new PGE common stock in both the Marion County Circuit Court and the Oregon Court of Appeals. On July 19, 2006, the Court of Appeals granted an OPUC motion to dismiss the action before that Court and, on November 2, 2006, the Marion County Circuit Court dismissed the case upon the request of the City of Portland.

Separation Agreement -

On April 3, 2006, PGE and Enron entered into a separation agreement, as required by the OPUC order that approved the distribution of new PGE common stock. The separation agreement provides generally for the settlement of intercompany amounts, the termination of intercompany agreements between PGE and Enron (except for certain provisions of a previously executed separate tax allocation agreement), and certain indemnifications for PGE from Enron related to Enron-sponsored employee benefit plans and certain liabilities related to taxes that may be imposed as the result of PGE's inclusion in Enron's consolidated tax group.

Release from Enron Pension Plan Liability -

On May 8, 2006, the Pension Benefit Guaranty Corporation (PBGC) and PGE entered into a release with respect to the Enron Corp. Cash Balance Plan and the pension plans of other Enron debtor subsidiaries (Pension Plans). The PBGC irrevocably and unconditionally forever released, acquitted and discharged PGE and its subsidiaries and affiliates and each of their past and present officers, agents, directors, employees and representatives from all liability under Title IV of the Employee Retirement Income Security Act of 1974 with respect to the Pension Plans.

Oregon Tax Credits -

PGE generated approximately $15 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. In prior years, PGE was able to utilize these tax credits to reduce its tax payment obligation to Enron pursuant to a tax sharing agreement. Uncertainties exist with respect to the timing and ability by Enron to utilize the credits. To the extent that Enron is unable to utilize these credits on its tax returns, PGE expects that it will be able to utilize such tax credits on its Oregon income tax returns in periods subsequent to its separation from Enron. Any amounts not utilized by PGE on its Oregon income tax return for the period April 3, 2006 through December 31, 2006 are expected to be available for carryover and utilization in future years. PGE had quarterly income tax payments due to the State of Oregon during 2006. A portion of the tax credits was utilized to offset these liabilities with no effect on income. Any realization of these tax credits will be reflected as an adjustment to equity.

Resource Valuation Mechanism

PGE's RVM tariff mechanism was used to update the Company's net variable power costs for inclusion in base rates from 2003 through January 16, 2007. It utilized a combination of market prices and the value of the Company's resources to establish power costs and set prices for energy services. Based upon projections of net variable power costs contained in PGE's RVM filings covering the last three years, the OPUC authorized average retail price increases of 0.4% for 2004, 1.4% for 2005, and 3.7% for 2006. Such adjustments increased the Company's revenues by approximately $4 million in 2004, $17 million in 2005, and $47 million in 2006. Based upon projections in PGE's 2007 RVM filing (which was consolidated with the Company's general rate case filing), the OPUC authorized an approximate 5.1% average retail price increase for 2007, which is expected to increase PGE's 2007 revenues by approximately $74 million.

General Rate Case

In March 2006, PGE filed a general rate case and proposed tariffs with the OPUC that would increase rates by 8.9%, providing for approximately $143 million in additional revenues and a 10.75% return on equity, based on a 56% equity capital structure. The proposed increase related to increases in power and fuel costs (as included in the Company's RVM process), general costs, and recovery of PGE's investment in Port Westward. The filing was the Company's first general rate increase request since 2001.

On January 12, 2007, the OPUC issued an order approving an overall price increase of approximately 1.3%, which will be allocated to all PGE customer classes. The increase represents the combined effect of a 2.8% increase related to cost recovery of Port Westward, to become effective when the plant goes into service, expected to be in late April 2007, and a 1.4% decrease related to general costs, which became effective on January 17, 2007. The decrease related to general costs primarily reflects reductions in forecasted test year costs and the effects of decisions related to the cost of capital. The OPUC previously approved a 5.1% price increase for increased power and fuel costs in PGE's RVM filing, which became effective on January 1, 2007. The change in retail prices is based upon a 50% equity capital structure, a 10.1% return on equity (ROE), and an overall rate of return of 8.29%. The overall increase in annual revenues approved by the OPUC for 2007 for the RVM, the general rate case, and Port Westward proceedings was $94.6 million, or 6.4%. The OPUC also established a process for reexamining the Port Westward rate increase if the plant in service date is delayed beyond April 29, 2007.

The OPUC also approved a process by which PGE can continue to adjust prices to reflect power cost variations in future years. An Annual Power Cost Update Tariff, which replaces the RVM, provides for rate adjustments to reflect updated forecasts of net variable power costs (NVPC) for future calendar years. PGE's initial filing under this Tariff, to be submitted to the OPUC by April 1, 2007, will include a forecast of NVPC, and any changes in retail prices, for 2008. In addition, a new PCAM provides for annual rate adjustments that reflect a portion of the difference between each year's actual NVPC and that forecast in the Annual Power Cost Update. The PCAM provides for application of an earnings test that will allow PGE to recover, or require the Company to refund, up to 90% of the difference between actual and forecast power costs, depending upon how much PGE's actual earnings vary from the Company's allowed ROE. The PCAM will produce a possible refund to customers of 90% of the amount by which actual NVPC is less than forecasted NVPC in excess of an amount equal to 75 basis points of PGE's ROE. For 2007, 75 basis points of ROE will be determined as a function of the in service date of Port Westward. Prior to Port Westward, the annualized impact of 75 basis points of ROE is $10.7 million. After Port Westward's in service date, the annualized impact of 75 basis points of ROE is $12.4 million. The PCAM will produce a possible collection from customers of 90% of the amount by which actual NVPC is greater than forecasted NVPC in excess of an amount equal to 150 basis points of PGE's ROE. For 2007, 150 basis points of ROE will be determined a function of the in service date of Port Westward. Prior to Port Westward, the annualized impact of 150 basis points of ROE is $21.4 million. After Port Westward's in service date, the annualized impact of 150 basis points is $24.8 million. A refund will occur only to the extent that it results in PGE's actual ROE for that year being no less than 100 basis points 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 100 basis points below the Company's last authorized ROE.

Utility Rate Treatment of Income Taxes

In 2005, the Oregon legislature passed a law that adjusts the way that PGE and other Oregon investor-owned electric and gas utilities recover income tax expense from customers through revenues for utility services. The law, commonly referred to as SB 408 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 investor-owned utilities or their consolidated group. The new law requires that utilities file a report with the OPUC each year regarding the amount of taxes paid by the utility or its consolidated group (with certain adjustments), as well as the amount of taxes authorized to be collected in rates, as defined by the statute. This report is to be 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 establish an "automatic adjustment clause" to adjust rates. The first adjustment under the automatic adjustment clause applies only to taxes paid to units of government and collected from customers on or after January 1, 2006.

On September 14, 2006, the OPUC issued a final order (Final Order) that adopted permanent rules (Rules) to implement SB 408. In the Rules, the OPUC adopted the use of fixed reference points for margins and effective tax rates from a ratemaking proceeding. The OPUC also adopted a methodology to determine the amounts properly attributed to the utility from a consolidated tax payment using a formula to determine the ratio of the utility's payroll, property and sales to the consolidated group's amounts for the same items. This ratio is then multiplied by the amount of total taxes paid by the consolidated group to determine the utility's attributed portion. The OPUC also determined that interest should begin to accrue beginning January 1, 2006 using a mid-year convention for differences between income taxes collected and income taxes paid to governmental entities for tax year 2006.

In the Final Order, the OPUC addressed the so-called "double whammy" effect wherein the application of the Rules can result in unusual outcomes in certain situations. If a utility incurs higher expenses or receives lower revenues, resulting in lower taxes paid than the OPUC assumed it would incur in its last rate case, the automatic adjustment clause under SB 408 will require the utility to make a refund to customers and decrease the utility's earnings. Conversely, if a utility incurs lower expenses or receives higher revenues, resulting in higher taxes paid than the OPUC assumed it would incur in its last rate case, the automatic adjustment clause under SB 408 will surcharge customers and increase the utility's earnings. The OPUC stated in the Final Order that it will be responsive to concerns related to the consequences of the "double whammy" problem, and may address those concerns in other regulatory proceedings; however, it did not provide clear guidance on avenues of relief.

On December 30, 2005, PGE filed with the OPUC an application for deferred accounting to prevent either the financial enrichment or financial harm to the Company should the rules implementing SB 408 include the use of fixed reference points for margins and effective tax rates from a ratemaking proceeding. The Rules do use fixed reference points for margins and effective tax rates from a ratemaking proceeding. The deferred amount would reflect the tax effect of the difference between PGE's implied operating costs under a fixed margin assumption and the Company's actual operating costs. In an interim order in the rulemaking process, the OPUC indicated that it would review deferral applications related to SB 408 on a case-by-case basis, but would view such applications with skepticism.

Effective with the April 3, 2006 issuance of new PGE common stock, PGE is no longer a subsidiary of Enron and files its own consolidated tax returns and remits payments directly to taxing authorities. However, in April 2006, PGE paid $17 million to Enron for net current taxes payable for the first quarter of 2006 when PGE was still included in Enron's consolidated group for filing consolidated federal and state income tax returns. Under the Rules, PGE will likely be required to refund to customers the majority of that amount.

As a result of its assessment of the Rules, PGE has estimated its potential refunds to customers to be approximately $42 million (including $2 million of accrued interest) for 2006 and has recorded a (pre-tax) reserve of such amount for the year. In accordance with the statute, the Company will file a report with the OPUC by October 15, 2007 for the 2006 tax year regarding the amount of taxes paid by the Company as well as the amount of taxes authorized to be collected in rates, as defined by the statute. Any refunds to customers for the 2006 tax year would begin after June 1, 2008.

PGE will continue to evaluate its options for changing or modifying the legislation and Rules, and challenging any adjustment that follows for the 2006 tax year.

Complaint and Application for Deferral - Income Taxes

On October 5, 2005, the Utility Reform Project and Ken Lewis (Complainants) filed a Complaint with the OPUC alleging that, since September 2, 2005 (the effective date of SB 408), PGE's rates are not just and reasonable and are in violation of SB 408 because they contain approximately $92.6 million in annual charges for state and federal income taxes that are not being paid to any government. The Complaint requests that the OPUC order the creation of a deferred account for all amounts charged to ratepayers 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.

Also on October 5, 2005, the Complainants filed an Application for Deferred Accounting with the OPUC, claiming that PGE is charging ratepayers $92.6 million annually for federal and state income taxes that are not being paid, and that such charges are not fair, just and reasonable. The Application for Deferred Accounting requests that the portion of PGE's revenue representing estimated PGE liabilities for federal and state income taxes, less any amounts of federal and state income taxes paid by PGE or on behalf of PGE, be deferred for later incorporation in rates. PGE opposes the deferral and has moved to dismiss the Complaint.

On July 10, 2006, the OPUC commenced proceedings on the Complaint and Deferral. Management cannot predict the ultimate outcome of this matter or estimate any potential loss.

Class Action Lawsuit - Multnomah County Business Income Taxes

In January 2005, David Kafoury and Kafoury Brothers, LLC filed a class action lawsuit in Multnomah County Circuit Court against PGE on behalf of all PGE customers who were billed on their electric bills and paid amounts for Multnomah County Business Income Taxes (MCBIT) after 1996 that the plaintiffs alleged were never paid to Multnomah County. The plaintiffs sought judgment against PGE for restitution of MCBIT in excess of $6 million, plus interest, recoverable costs, punitive damages, and attorney fees.

On July 28, 2006, the Multnomah County Circuit Court approved a settlement providing for PGE refunds and payments totaling $10 million, inclusive of interest and plaintiffs' attorney fees, costs, and expenses as approved by the Court's final order. The settlement includes no admission of liability or wrongdoing by the Company. PGE established a reserve of $10 million in 2005 related to the settlement. Refunds to customers were completed in the fourth quarter of 2006.

City of Portland Actions

The City of Portland has indicated that it may pursue ratemaking for PGE's retail customers who reside within the City of Portland's boundaries. In September 2005, the Portland City Council approved a resolution directing the City Attorney and City staff to obtain from PGE information regarding the collection and payment of utility income taxes. PGE voluntarily provided extensive financial and operational data to the City of Portland. The City of Portland subsequently broadened its inquiry to include PGE's power trading activities in 2000 and 2001 and requested that PGE provide many additional documents and records, and on March 23, 2006 issued a subpoena to PGE seeking numerous records and documents. PGE determined that there are a number of legal and practical issues concerning the City of Portland's subpoena and other requests for additional information, and has declined to provide any additional data to the City of Portland while those issues remain unresolved. On April 21, 2006, PGE filed a complaint in Multnomah County Circuit Court seeking clarity on whether the City of Portland has investigatory and ratemaking authority. The City of Portland has agreed not to seek enforcement of the subpoena while this case is pending.

On May 5, 2006, the City of Portland filed a complaint against PGE with the OPUC. The complaint alleged that Enron and PGE should not have filed income taxes on a unitary basis under Oregon law. The complaint also alleged that PGE made certain cash payments to Enron under a tax allocation agreement which at the time had not been approved by the SEC, and that PGE did not submit the agreement to the OPUC for a determination as to whether the agreement was fair and reasonable and in the public interest as required under Oregon law.

On July 31, 2006, the OPUC dismissed the claims related to unitary basis tax filing and SEC approval of the tax allocation agreement. On August 16, 2006, PGE filed a motion for summary judgment seeking dismissal of the remaining claims, which the OPUC granted on November 17, 2006.

Boardman Coal Plant - Repair Outages

On October 22, 2005, Boardman was taken out of service to repair its steam turbine rotor. On February 6, 2006, during the process of returning the plant to operation, the generator rotor was damaged and subsequently removed for repair. The generator rotor was repaired and the plant was operational in late May. In early June, the plant was again taken out of service for repairs to its low pressure turbine unit; upon completion of these repairs, the plant returned to full operation on July 1, 2006.

The extended outages of Boardman required that PGE replace its portion of the plant's generation with both higher cost purchases in the wholesale market and increased generation from the Company's natural gas-fired generating plants. Incremental power costs during the plant's outages totaled approximately $92 million, including $44 million in the first quarter and $8 million in the second quarter of 2006. Reduced replacement power costs in the second quarter of 2006 reflect the impact of favorable regional hydro conditions on wholesale power prices.

On November 18, 2005, PGE filed with the OPUC an "Application for Deferred Accounting of Excess Power Costs Due to Plant Outage." The application requested an order authorizing PGE to defer for later ratemaking treatment excess power costs associated with that portion of Boardman's outage related to repair of the plant's steam turbine rotor and covered the period from the November 18, 2005 application date through February 5, 2006. The application requested deferral of approximately $46 million, representing the difference between Boardman's variable power costs used in setting rates for 2005 and 2006 (under PGE's RVM) and replacement power costs incurred during the outage. Based upon prior OPUC actions, the stated position of the OPUC staff in the proceeding, and considering both applicable accounting guidance and the impact of SB 408 on any benefit received by the Company, PGE recorded a deferral in the amount of $6 million at December 31, 2006.

On February 12, 2007, the OPUC issued an order authorizing PGE to defer for future rate recovery $26.4 million of excess power costs resulting from Boardman's extended outage. Amortization will be determined in a future ratemaking proceeding that will include a prudency review of PGE's actions with respect to the outage and acquisition of replacement power and a determination as to whether recovery of the deferred amount will cause PGE's earnings to exceed a reasonable range. In its order, the OPUC indicated that the outage was significant, unique and outside the foreseen range of risk for forced outages. The order reduced PGE's estimate of the total net cost of the outage (the amount eligible for deferral) to approximately $42.8 million. The OPUC imposed a sharing mechanism that divides responsibility for the outage costs between PGE's customers and shareholders and that also includes an adjustment related to the effects of SB 408. Under the applicable accounting standards, the $20.4 million difference between the $26.4 million authorized deferral and the $6 million recorded in 2006 will be recorded in 2007.

Under the RVM process, a 4-year rolling average of historical forced outages of PGE's generating plants was used in projecting plant availability and expected power costs. In its January 12, 2007 general rate case order, the OPUC approved a 4-year rolling average forced outage rate for Boardman that excluded the 2005 portion of the outage covered by the November 18, 2005 deferral application. PGE did not file an application to defer incremental power costs related to the generator rotor outage or the low pressure turbine outages (February 6, 2006 through June 6, 2006) and will not propose the inclusion of these outages in the 4-year rolling average of forced outages in its annual power cost update filings starting in 2008 or in future general rate case proceedings.

Port Westward Generating Plant

In February 2005, pursuant to PGE's strategy to meet the electric energy needs of its customers outlined in its Integrated Resource Final Action Plan, PGE began construction of Port Westward, a 400 MW natural gas-fired facility located in Clatskanie, Oregon. Construction is proceeding, with the plant expected to go into service in late April 2007. Total cost of the plant is estimated at between $275 million and $295 million, including Allowance for Funds Used During Construction (AFDC).

Biglow Canyon Wind Farm

In accordance with PGE's plan to acquire additional wind generation, as outlined in its IRP, the Company is proceeding with construction of the Biglow Canyon Wind Farm, located in Sherman County, Oregon. PGE currently plans to construct the project in three phases over a five-year period. The first phase of the project, which will be owned and operated by PGE, will have a capacity of 125 MW. It is expected to be completed by the end of 2007 at a total estimated cost of $250 million to $260 million (including AFDC). In November 2006, PGE executed an agreement to acquire 76 wind turbines for the project's first phase and in February 2007 entered into a contract for the balance of plant construction. The Company will file a rate application with the OPUC on March 2, 2007 seeking an approximate $13 million increase in annual revenue requirements for full recovery of all costs related to the first phase of the Biglow Canyon Wind Farm.

Hydro Relicensing

The 30-year license for PGE's Clackamas River Hydroelectric Project expired on August 31, 2006. The Company filed an application with the FERC in 2004 to relicense the project. 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 on March 2, 2006 and was submitted to the FERC for review and approval. Pending approval of the new license, the project will operate under annual licenses issued by the FERC. The settlement agreement provides for improved fish and wildlife protection and recreational opportunities at the hydro facilities. It 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. Although it is not certain when the FERC will issue a new license for the Clackamas River Project, it is expected that the license will be issued by 2009.

Mid-Columbia Hydro Matters

PGE's long-term power purchase contracts with certain public utility districts in the state of Washington expire between 2009 and 2018. In 2001, PGE executed new agreements with Grant County Public Utility District (Grant), operator of the Priest Rapids and Wanapum projects, for periods corresponding to Grant's new license term, to be determined by the FERC. The Priest Rapids agreement became effective in November 2005 and the Wanapum agreement will become effective November 1, 2009. Both contracts, approved by the FERC, extend through the life of Grant's new license, which is expected to be approximately 50 years. Under the terms of the agreements, Grant will annually determine the output required for its purposes, while PGE will be required to purchase approximately 25% of the output in excess of Grant's requirements over the term of the new license, for which PGE will pay a proportional share of the project's debt service and operating costs. PGE's share in the projects is expected to steadily decline as Grant's needs increase, with the Company's share in the two projects reduced from the current 259 MW to an estimated 149 MW in 2010. Also under the agreements, PGE is to purchase an additional 50 MWa annually during the period 2006-2011.

For further information regarding PGE's power purchase contracts from mid-Columbia projects, see Note 9, Commitments and Guarantee, in the Notes to Financial Statements.

Trojan Investment Recovery

In 1993, following the closure of the Trojan Nuclear Plant as part of its 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.

Numerous challenges, appeals and reviews were subsequently filed in the Marion County 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 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 Utility Reform Project each requested the Oregon Supreme Court to 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 has been remanded to the OPUC (1998 Remand).

In 2000, while the petitions for review of the 1998 Court of Appeals decision were pending at the Oregon Supreme Court, PGE, the Citizens Utility Board, 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 settlement agreements, 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. The Utility Reform Project (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 URP's challenges, and approving the accounting and ratemaking elements of the 2000 settlement. URP appealed the 2002 Order to the Marion County Circuit Court and on November 7, 2003, the Marion County Circuit Court issued an opinion remanding the case to the OPUC for action to reduce rates or order refunds (2003 Remand). The opinion does not specify the amount or timeframe of any reductions or refunds. PGE and the OPUC have appealed the 2003 Remand to the Oregon Court of Appeals.

The OPUC combined the 1998 Remand and the 2003 Remand into one proceeding and is considering the matter in phases. The first phase addresses what rates would have been if the OPUC had interpreted the law to prohibit a return on the Trojan investment. The subsequent phases will address reconciling the results of the first phase with actual rates, and adjusting rates to the extent necessary. A decision is pending in the first phase of the proceeding. On November 15, 2006, PGE filed a motion with the OPUC to Consolidate Phases and Re-Open the Record. A ruling on the motion is pending.

On February 16, 2007, the Oregon Court of Appeals declined to reverse or abate the 2003 Remand and ordered the parties to file revised briefs with the Court of Appeals.

In a separate legal proceeding, two class action suits were filed in Marion County 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 for the Current Class and $70 million for the Former Class, as a result of the inclusion of a return on investment of Trojan in the rates PGE charges 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 these class action proceedings until the OPUC responds 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 rate reductions or refunds, for any amount of return on the Trojan investment PGE collected in rates for the period from April 1995 through October 2000. The Supreme Court further stated that if the OPUC determines that it can provide a remedy to PGE's customers, then the class action proceedings may become moot in whole or in part, but if the OPUC determines that it cannot provide a remedy, and that decision becomes final, the court system may have a role to play. The Supreme Court also ruled that the plaintiffs retain the right to return to the Marion County Circuit Court for disposition of whatever issues remain unresolved from the remanded OPUC proceedings. 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.

Threatened Litigation - Class Action Lawsuit -

On February 14, 2005, PGE received a Notice of Potential Class Action Lawsuit for Damages and Demand to Rectify Damages from counsel representing Frank Gearhart, David Kafoury and Kafoury Brothers, LLC (Potential Plaintiffs), stating that Potential Plaintiffs intend to bring a class action lawsuit against the Company. Potential Plaintiffs allege that for the period from October 1, 2000 to the present, PGE's electricity rates have included unlawful charges for a return on investment in Trojan in an amount in excess of $100 million. Under Oregon law, there is no requirement as to the time the lawsuit must be filed following the 30-day notice period. No action has been filed to date.

Management cannot predict the ultimate outcome of the above matters. However, it believes that the resolution will not have a material adverse impact on the financial condition of the Company, but may have a material impact on the results of operations and cash flows for a future reporting period. No reserves have been established by PGE for any amounts related to this issue.

Nuclear Decommissioning

PGE has completed all radiological decommissioning activities at Trojan and, upon approval of the Nuclear Regulatory Commission (NRC), the plant's operating license was terminated on May 23, 2005. Previously, the steam generators, reactor containment vessel, and other major components were removed and transported to a licensed low level radioactive waste disposal facility in Washington State for permanent storage. Spent nuclear fuel has been stored in the Independent Spent Fuel Storage Installation (ISFSI), an interim dry storage facility that houses the fuel at the plant site until permanent off-site storage is available. Spent fuel storage activities will continue to be subject to NRC regulation until all nuclear fuel is removed from the site, decontamination is completed, and the storage installation is fully decommissioned. The plant's cooling tower was successfully imploded in May 2006 and removal of the plant's containment building is scheduled for 2008. Remaining activities include demolition of the fuel, auxiliary, turbine, and control buildings, and long-term operation and decommissioning of the ISFSI.

PGE has recorded an ARO for Trojan decommissioning of $108 million, measured at estimated fair value, as of December 31, 2006. The ARO estimate assumes that the majority of decommissioning activities were completed at the end of 2006, with remaining costs extending through 2030. The plan anticipates final site restoration activities will begin in 2031 after PGE completes shipment of spent fuel to a USDOE facility. Decommissioning expenditures are estimated at $7 million for 2007, compared to $5 million in 2006.

In 2002, the USDOE formally recommended Yucca Mountain, Nevada as the nation's first long-term geologic (underground) repository for high-level radioactive waste produced in the United States. The proposed location is based on the conclusions of scientific studies of the site, conducted over 20 years, which support a finding of suitability as mandated by the Nuclear Waste Policy Act and various regulations of the NRC, USDOE, and the EPA. The House and Senate approved the site and in 2002, President Bush signed the Yucca Mountain resolution into law. Lawsuits have been filed objecting to the recommendation of Yucca Mountain as a nuclear waster repository. Based upon updated information received from the USDOE regarding the acceptance of spent nuclear fuel from Trojan, PGE has extended its projection for the final shipment of spent fuel from 2023 to 2030. Although it has not yet submitted the required application for an operating license for the repository, the USDOE in July 2006 announced plans to submit a license application to the NRC by June 30, 2008. Further delays may make it difficult for PGE to move its spent nuclear fuel, currently contained in the ISFSI, to permanent underground storage by 2030.

In 2004, the co-owners of Trojan (PGE, Eugene Water & Electric Board, and PacifiCorp) filed a complaint against the USDOE in the U.S. Court of Federal Claims for failure to accept spent nuclear fuel by January 31, 1998, as required by the Standard Form Contract. The plaintiffs paid for permanent disposal services during the period of plant operation (in the total amount of $109 million) and have met all other conditions precedent. Damages sought are in excess of $200 million.

The Energy Policy Act of 1992 provided for the creation of a Decontamination and Decommissioning Fund to finance the cleanup of USDOE gas diffusion plants, with funding provided by both domestic nuclear utilities and the federal government. Contributions are based upon each utility's share of total enrichment services purchased by all domestic utilities prior to enactment of the legislation. PGE's $17 million share of the total funding requirement, based on Trojan's 1.1% usage of total industry enrichment services, was paid in annual installments that began in 1993, with the final payment made in November 2006.

In response to the terrorist attacks of September 11, 2001, the NRC issued interim compensatory security measures for a generalized high-level threat environment at closed nuclear reactors that are in the decommissioning process and at ISFSIs. The new requirements are expected to remain in effect until the NRC determines that the level of threat has diminished, or that other security changes are needed. The NRC issued additional security orders to all operating reactors in 2003 that require operating plants to update their defensive strategies to counter a highly organized attack. It is possible that corresponding similar orders (limited in scope) will eventually be issued to the Trojan ISFSI. Until NRC requirements associated with any new orders are determined, any implementation costs (including their impact on the Trojan decommissioning cost estimate and related funding requirements) are not determinable. However, as any new security requirements are evaluated, any additional costs will be determined and decommissioning cost estimates revised as necessary.

Receivables and Refunds on Wholesale Market Transactions

Receivables - California Wholesale Market

As of December 31, 2006, PGE has net accounts receivable balances totaling approximately $63 million from the California Independent

System Operator (ISO) and the California Power Exchange (PX) for wholesale electricity sales made from November 2000 through February 2001. The Company estimates that the majority of this amount was for sales by the ISO and PX to Southern California Edison Company and Pacific Gas & Electric Company.

In March 2001, the PX filed for bankruptcy and in April 2001, Pacific Gas & Electric Company filed a voluntary petition for relief under the provisions of Chapter 11 of the federal Bankruptcy Code. PGE filed a proof of claim in each of the proceedings for all past due amounts. Although both entities have emerged from their bankruptcy proceedings as reorganized debtors, not all claims filed in the proceedings, including those filed by PGE, have been resolved. PGE is continuing to pursue collection of these claims.

Management continues to assess PGE's exposure relative to these receivables. Based upon FERC orders regarding the methodology to be used to calculate refunds related to California wholesale sales (see "Refunds on Wholesale Transactions" below) and the FERC's indication that potential refunds can be offset with accounts receivable related to such sales, PGE has established reserves totaling $40 million related to this receivable amount. The Company is examining numerous options, including legal, regulatory, and other means, to pursue collection of any amounts ultimately not received through the bankruptcy process.

<u>Refunds on Wholesale Transactions</u>

California

- On July 25, 2001, the FERC issued an order in the California refund case (Docket No. EL00-95) establishing the scope of and methodology for calculating refunds for wholesale sales transactions made between October 2, 2000 and June 20, 2001 in the spot markets (defined by the FERC as 24 hours or less) operated by the ISO and PX. The order established evidentiary hearings to develop a factual record to provide the basis for the refund calculation. Several additional orders clarifying and further defining the methodology were issued by the FERC and all have been appealed by numerous parties. A hearing was held in 2002 and, on March 26, 2003, the FERC issued an order ruling on various outstanding issues as to how refunds were to be determined. Under this order, PGE estimates its potential liability at between $40 million and $50 million, of which $40 million has been established as a reserve, as discussed above.

Numerous parties, including PGE, filed requests for rehearing of various aspects of the March 26, 2003 order, including the methodology for the pricing of natural gas within the refund formula. On October 16, 2003, the FERC issued an order reaffirming, in large part, the methodology adopted in its March 26, 2003 order. PGE does not agree with the FERC's methodology for determining potential refunds, and, on December 20, 2003 the Company appealed the FERC's October 16, 2003 order to the U.S. Ninth Circuit Court of Appeals; several other parties have also appealed the October 16, 2003 order. On May 12, 2004, the FERC issued an order that denied further requests for rehearing of the October 16, 2003 order. Although there continue to be miscellaneous orders issued in the underlying FERC proceeding, the Ninth Circuit has now begun to hear the numerous appeals. It bifurcated appeals of the existing cases into two phases. The first phase (Phase I) considered arguments regarding jurisdictional issues and the permissible scope of refund liability, both in terms of the time frame for which refunds were ordered and the types of transactions subject to refund. The second phase will consider the issues relating to the refund methodology itself. PGE expects that the Court will establish additional phases as the issues remaining before the FERC become final and are appealed.

As to the jurisdictional issues in Phase I, on September 6, 2005, the Court ruled that the FERC did not have jurisdiction to order municipal utilities and other governmental entities to make refunds for the sales they had made to the ISO and PX that are the subject of the refund proceeding. Requests for rehearing have been filed with regard to this decision.

On August 2, 2006, the Ninth Circuit issued its decision on the remainder of the issues in Phase I

(Refund Scope Decision). It upheld the refund effective date of October 2, 2000, but remanded to the FERC the issue of whether it should order refunds for the summer 2000 period pursuant to its authority under Section 309 of the Federal Power Act (FPA) to remedy tariff violations. It also affirmed the FERC's orders on the scope of the refund proceeding, except with regard to the FERC's exclusion of ISO and PX contracts in excess of 24 hours and energy exchanges, and held that transactions in the ISO and PX markets with a duration in excess of 24 hours, as well as energy exchanges, should be included within the scope of the refund case. Although the August 2, 2006 Ninth Circuit decision did not mandate industry-wide refunds for the summer 2000 period, it is possible that, upon remand, the FERC could decide to order such additional refunds. Management cannot predict the outcome of any proceeding or how summer refunds, if they are ordered, might be calculated.

The Ninth Circuit has ordered an extension of the due date for the filing of requests for rehearing of its Refund Scope Decision until April 29, 2007, establishing a mediation process and urging the parties to use the time to assess possibilities of settlement.

Within the refund case, the FERC also issued a series of orders that permit generators serving California to recover certain costs of emission allowances and the costs of fuel incurred to generate power that were in excess of the gas cost component used to establish the refund liability. Under the methodology adopted by the FERC to allocate fuel costs, PGE could be required to pay additional amounts in those hours when it was a net buyer in California spot markets, thus increasing its net refund liability. PGE does not expect a material increase in the Company's potential refund exposure. Partly as a means of limiting its exposure to additional fuel costs and other potential refund liabilities, PGE has opted to become a participant in several settlements filed in the refund case since 2004.

In August 2005, PGE joined in a settlement agreement resolving issues relating to the allocation of the wind-up costs of the PX for both past and future periods. The settlement has been approved by the FERC. Although under the agreement PGE will bear certain additional costs associated with PX obligations to conduct and finalize refund calculations, PGE does not expect those costs to be material to its financial statements.

In several of its underlying refund orders, the FERC has indicated that if marketers, such as PGE, believe that the level of their refund liability has caused them to incur an overall revenue shortfall for their sales to the ISO and PX during the refund period, they will be permitted to file a cost study to prove that they should be permitted to recover additional revenues in excess of the mitigated prices in order to cover their costs. By order issued August 8, 2005, the FERC provided guidelines regarding the manner in which these studies should be conducted and the principles that should govern their preparation. On September 14, 2005, PGE filed a cost recovery study with the FERC. By order issued November 2, 2006, the FERC accepted, subject to PGE making certain additional revisions, a revised cost recovery study that had been filed by PGE in response to an earlier January 26, 2006 order. Pursuant to the November 2, 2006 order, PGE filed a final cost study with the ISO that now reflects an approximate $19.8 million cost offset to its refund obligation. Third parties have challenged PGE's cost recovery filings and made numerous requests that they be rejected in their entirety or that the cost offset be reduced to zero. PGE has filed responses to those challenges.

PGE believes that the FERC erred in certain findings in its orders regarding PGE's cost recovery, and has filed requests for rehearing as to several issues in those orders. Due to the continuing uncertainty related to these matters, PGE has made no adjustment to the $40 million reserve previously established for the Company's potential liability, as described above.

The FERC has indicated that any refunds PGE may be required to pay related to California wholesale sales (plus interest from collection date) can be offset by accounts receivable (plus interest from due date) related to sales in California (see "Receivables - California Wholesale Market" above). In addition, any refunds paid or received by PGE applicable to spot market electricity transactions on and after January 1, 2001 in California may be eligible for inclusion in the calculation of net variable power costs under the Company's power cost adjustment mechanism in effect at that time. This could further mitigate the financial effect of any refunds made or received by the Company.

Challenge of the California Attorney General to Market-Based Rates -

On March 20, 2002, the California Attorney General filed a complaint with the FERC against various sellers in the wholesale power market, alleging that the FERC's authorization of market-based rates violated the FPA, and, even if market-based rates were valid under the FPA, that the quarterly transaction reports required to be filed by sellers, including PGE, did not contain the transaction-specific information mandated by the FPA and the FERC. The complaint argued that refunds for amounts charged between market-based rates and cost-based rates should be ordered. The FERC denied the challenge to market-based rates and refused to order refunds, but did require sellers, including PGE, to re-file their quarterly reports to include transaction-specific data. The California Attorney General appealed the FERC's decision to the Ninth Circuit. On September 8, 2004, the Court issued an opinion upholding the FERC's authority to approve market-based tariffs, but also holding that the FERC had the authority to order refunds, if quarterly filing of market-based sales transactions had not been properly made. The Court required the FERC, upon remand, to reconsider whether refunds should be ordered. On October 25, 2004, certain parties filed a petition for rehearing with the Court. On July 31, 2006, the Court summarily denied rehearing, and on December 28, 2006, PGE joined with other parties in filing a petition for certiorari of this decision with the U.S. Supreme Court. On February 5, 2007, the California Attorney General filed in opposition to the petition for certiorari, or, in the alternative if the petition is granted, a cross-petition for certiorari challenging the legality of market-based rate tariffs. In the refund case and in related dockets, including the above challenge to market based rates, the California

Attorney General and other California parties have argued that refunds should be ordered retroactively to at least May 1, 2000. Management cannot predict the outcome of these proceedings or whether the FERC will order refunds retroactively to May 1, 2000, and if so, how such refunds would be calculated.

Anomalous Bidding Allegations -

By order issued on June 25, 2003, the FERC instituted an investigation into allegations of anomalous bidding activities and practices ("economic withholding") on the part of numerous parties, including PGE. The FERC determined that bids above $250 per MW in the period from May 1, 2000 through October 2, 2000 may have violated tariff provisions of the ISO and the PX. The FERC required companies that bid in excess of $250 per MW to provide information on their bids to the FERC investigation staff. PGE responded to the FERC's inquiries and, on May 12, 2004, the FERC investigation staff issued to PGE a letter terminating the investigation as to the Company without further action. On March 10, 2005, certain California parties filed appeals with the Ninth Circuit, contesting the FERC's conduct of the investigation of the anomalous bidding allegations and the issuance of the dismissal letters.

Pacific Northwest -

In the July 25, 2001 order, the FERC also 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 July 2003, numerous parties filed requests for rehearing of the June 2003 FERC order. In November 2003 and February 2004, the

FERC issued orders that denied all pending requests for rehearing. Parties have appealed various aspects of these FERC orders. Briefing has been completed and oral argument was held on January 8, 2007. A decision in the case is pending.

Management cannot predict the ultimate outcome of the above matters related to wholesale transactions in California and the Pacific Northwest. However, it believes that the outcome will not have a material adverse impact on the financial condition of the Company, but may have a material impact on the results of operations and cash flows for future reporting periods.

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, in which PGE has a 20% ownership interest. In 2002 and 2003, WECO received two orders from the Office of Minerals Revenue Management of the U.S. Department of the Interior which asserted underpayment of royalties and taxes by WECO related to transportation of coal from the mine to Colstrip during the period October 1991 through December 2001. WECO subsequently appealed the two orders to the Minerals Management Service (MMS) of the U.S. Department of the Interior. On March 28, 2005, the appeal by WECO was substantially denied. On April 28, 2005, WECO appealed the decision of the MMS to the Interior Board of Land Appeals of the U.S. Department of the Interior. In late September 2006, WECO received an additional order from the Office of Minerals Revenue Management to report and pay additional royalties for the period January 2002 through December 2004.

In May 2005, WECO received a "Preliminary Assessment Notice" from the Montana Department of Revenue, asserting claims similar to those of the Office of Minerals Revenue Management.

WECO has indicated to the owners of Colstrip Units 3 and 4 that, if WECO is unsuccessful in the above appeal process, it will seek reimbursement of any royalty payments by passing these costs on to the owners. *The owners of Colstrip Units 3 & 4 advised WECO that their position would be that these claims are not allowable costs under either the Coal Supply Agreement or the Transportation Agreement.*

Management cannot predict the ultimate outcome of the above matters or estimate any potential loss. Based on information currently known to the Company's management, the Company does not expect that this issue will have a material adverse effect on its financial condition, results of operations or cash flows. If WECO is able to pass any of these costs on to the owners, the Company would most likely seek recovery through the ratemaking process.

Environmental Matters

Harborton

A 1997 EPA investigation of a 5.5-mile segment of the Willamette River known as the Portland Harbor revealed significant contamination of sediments within the harbor. The EPA subsequently included the Portland Harbor on the federal National Priority List pursuant to the federal Comprehensive Environmental Response, Compensation, and Liability Act (Superfund).

In December 2000, PGE received from the EPA a "Notice of Potential Liability" regarding the Harborton Substation facility. The notice listed sixty-eight other companies that the EPA believes may be Potentially Responsible Parties (PRPs) with respect to the Portland Harbor Superfund Site.

In February 2002, PGE provided a report on its remedial investigation of the Harborton site to the DEQ. The report concluded that the investigation demonstrated that there is no likely present or past source or pathway for release of hazardous substances to surface water or sediments in the Portland Harbor Superfund Site at or from the site and that the site does not present a high priority threat to present and future public health, safety, welfare, or the environment. The DEQ submitted the report to the EPA and, in a May 18, 2004 letter, the EPA notified the DEQ that, based on the summary information from the DEQ and the stage of the process, the EPA, as of that time, agreed, the Harborton site does not appear to be a current source of contamination to the river.

In December 6, 2005 letter, the DEQ notified PGE that the site is not likely a current source of contamination to the river and that the site is a low priority for further action. Management believes that the Company's contribution to the sediment contamination, if any, from the Harborton Substation site would qualify it as a de minimis PRP.

Sufficient information is currently not available to determine either the total cost of investigation and remediation of the Portland Harbor or the liability of PRPs, including PGE. Management cannot predict the ultimate outcome of this matter or estimate any potential loss. However, it believes this matter will not have a material adverse impact on the Company's financial statements.

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 is also 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 that impacted an approximate two acre area. Elevated levels of contaminants, including metals, pesticides, and polychlorinated biphenyls (PCBs), have been detected at the site. On September 29, 2003, following investigation and site assessment by the EPA, Harbor Oil was included on the federal National Priority List as a federal Superfund site.

PGE received a Special Notice Letter for Remedial Investigation/Feasibility Study 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 PRPs to participate in negotiations with the EPA to reach a settlement to conduct or finance a

Remedial Investigation and Feasibility Study of the Harbor Oil site. PGE, along with other PRPs, is negotiating an Administrative Order of Consent with the EPA to conduct a Remedial Investigation/Feasibility Study.

Sufficient information is currently not available to determine either the total cost of investigation and remediation of the Harbor Oil Site or the liability of PRPs, including PGE. Management cannot predict the ultimate outcome of this matter. However, it believes this matter will not have a material adverse impact on the Company's financial statements.

Air Quality

PGE's operations, principally its fossil-fuel electric generation plants, are subject to the federal Clean Air Act (CAA) and other federal regulatory requirements. 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 exceed federal standards. Primary pollutants addressed by the CAA that affect PGE are sulfur dioxide (SO_2), nitrogen oxides, carbon monoxide, and particulate matter. PGE manages its emissions by the use of low sulfur fuel, emission controls, emission monitoring, and combustion controls. Required operating permits have been obtained for all thermal generating facilities operated by PGE.

In May 2005, the EPA established the Clean Air Mercury Rule (CAMR), which regulates mercury emissions from the nation's coal-fired electric generating plants. The CAMR includes a federal "cap-and-trade" program (scheduled to begin in 2010), that establishes a cumulative total ("cap") of mercury emissions from all electric generating plants in the United States and assigns to each state a mercury emissions "budget." Individual states had the choice of adopting this model or establishing their own programs.

In October 2006, the Montana Board of Environmental Review adopted final rules on mercury emissions from coal-fired generating units in Montana, including Colstrip, which set strict mercury emission limits by 2010 and established a review process to ensure that such facilities continue to utilize the latest mercury emission control technology. The rules have been submitted to the EPA for review and determination of their compliance with CAMR requirements. PGE has a 20% ownership interest in Colstrip Units 3 and 4.

In December 2006, the Oregon Environmental Quality Commission adopted the Utility Mercury Rule, which limits mercury emissions from new coal-fired power plants in Oregon and requires installation of mercury technology on the Boardman plant and requires the plant to reduce its mercury emission by 90% by July 1, 2012. The rules allow limited mercury allowance trading up to 2018, after which time, no trading will be allowed.

On June 15, 2005, the EPA issued final amendments to its July 1999 Regional Haze Rule. The rule establishes goals to protect visibility and remedy existing impairments resulting from man made pollution. The revised guidelines require determinations of eligibility with respect to SO_2, nitrogen oxides, and particulate emissions. States must develop implementation plans by December 2007.

While it is not yet known what ultimate impact the federal and state regulations on air quality standards will have on future operations, operating costs, or generating capacity of PGE's thermal generating plants, the Company estimates that the capital cost (in 2006 dollars) to meet regional haze rules and install mercury controls at Boardman could be approximately $200 million - $300 million (100% of total project costs). PGE will seek to recover its share of such costs through the ratemaking process.

Boardman and Beaver -

The SO_2 emissions allowances awarded under the CAA, along with expected future annual allowances, are sufficient to operate Boardman at a 60% to 67% capacity. PGE has acquired additional emissions allowances, which, in combination with the allowance awards, will allow the operation of Boardman at forecasted capacity for at least the next ten years.

In accordance with federal regional haze rules, the Oregon DEQ is conducting an assessment of emission sources pursuant to a Regional Haze Best Available Retrofit Technology (RH BART) process. Those sources determined to cause, or contribute to, visibility impairment at protected areas will be subject to an RH BART Determination. Several other states are conducting a similar process. The DEQ is working with ten RH BART eligible sources in Oregon, including PGE's Boardman and Beaver generating plants. In January 2006, the Company volunteered to participate in a DEQ pilot project that will analyze information about air emissions from Boardman to determine their effect on visibility in the region, particularly in wilderness and scenic areas. An exemption modeling analysis for identified sources, which began in September 2006, has indicated that the Boardman facility may cause or contribute to visibility impairment in several protected areas.

Colstrip Plant -

PGE has a 20% ownership interest in Colstrip Units 3 and 4, which are operated by PPL Montana, LLC (PPL Montana). PPL Montana and the EPA are discussing possible emission control and monitoring requirements involving all Colstrip units to address certain issues that have arisen since late 2003, including those related to the CAA. Current emissions allowances are sufficient to operate Colstrip, which utilizes wet scrubbers.

In December 2003, PPL Montana, LLC (PPL Montana), the operator of the Colstrip coal fired generating plant, received an Administrative Compliance Order (ACO) from the EPA pursuant to the CAA. The EPA alleges that since 1980, Colstrip Units 3 and 4, have been in violation of the clean air permit issued under the CAA. The permit requires Colstrip Units 3 and 4 to submit, for review and approval by the EPA, an analysis and proposal for reducing NO_x emissions to address visibility concerns if and when the EPA establishes requirements for such emissions. The EPA asserts that regulations it established in 1980 triggered the requirement. PPL Montana has been in settlement negotiations with the EPA and the Northern Cheyenne Tribe to resolve this matter.

PPL Montana and the other Colstrip owners, as well as the Northern Cheyenne Tribe, have executed a consent decree that is now awaiting signature by the EPA. Following execution by all parties, the agreement is expected to be entered in the United States District Court for the District of Montana and the EPA's action would then be discontinued. The agreement calls for installation of low nitrogen oxide equipment on Colstrip Units 3 and 4, payment of a non-material penalty and financing of an energy efficiency project. The Company anticipates that its share of the capital improvements and other costs will total approximately $5.8 million, which it will seek to recover through the ratemaking process.

<u>Stock-Based Compensation</u>

On July 13, 2006, PGE granted restricted stock units (Stock Units) with time-based vesting conditions (Restricted Stock Units) and performance-based vesting conditions (Performance Stock Units) to non-employee members of the Company's Board of Directors, officers, and certain key employees. Each Stock Unit represents the right to receive one share of the Company's common stock at a future date, subject to applicable vesting requirements. The grants were made pursuant to the terms of the Portland General Electric Company 2006 Stock Incentive Plan, the purpose of which is to provide common stock-based incentives which will attract, retain, and motivate directors, officers, and key employees of the Company.

Effective July 1, 2006, PGE adopted SFAS No. 123R, Share-Based Payment, which requires that the compensation cost related to share-based payment transactions be recognized in financial statements at fair value, based on the market price of the underlying common stock on the date of grant, and charged to expense over the vesting period based on the number of shares expected to vest. The Company adopted SFAS No. 123R using the Modified Prospective Application method, which applies to new awards and to awards modified, repurchased, or cancelled as of the beginning of the period in which SFAS No. 123R is adopted. For the year ended December 31, 2006, PGE recorded $1 million of stock-based compensation. Based upon the attainment of performance goals that would allow the vesting of 100% of awarded Performance Stock Units, and utilizing an estimated forfeiture rate of 3%, unrecognized compensation expense related to unvested Stock Units was $3.7 million at December 31, 2006, of which $1.6 million, $1.4 million, and $0.7 million is expected to be expensed in 2007, 2008, and 2009, respectively.

Restricted Stock Units will be granted to non-employee directors, as part of their annual compensation arrangement, on or about July 1 each year. It is also anticipated that Stock Unit grants will be made to PGE officers and key employees in future years, resulting in "overlapping" vesting periods and an increase in recorded compensation expense and additional common stock equity.

For additional information, see Note 5, Stock-Based Compensation, in the Notes to Financial Statements.

New Accounting Standards

FASB Interpretation No. 48 (FIN 48), Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109, was issued in July 2006 and is effective for annual reporting periods beginning after December 15, 2006. FIN 48 seeks to reduce the diversity in practice associated with certain aspects of the recognition and measurement requirements related to accounting for income taxes. It requires that a tax position meet a "more-likely-than-not threshold" for the benefit of an uncertain tax position to be recognized in the financial statements. FIN 48 requires recognition in the financial statements of the best estimate of the effects of a tax position only if that position is more likely than not of being sustained on audit by the appropriate taxing authorities, based solely on the technical merits of the position. Based upon an assessment of the application of FIN 48 with respect to PGE's income taxes, the adoption of FIN 48 is not expected to have a material effect on the financial statements of the Company.

SFAS No. 157, Fair Value Measurements, was issued in September 2006 and is effective for fiscal years beginning after November 15, 2007. SFAS No. 157 provides enhanced guidance for the use of fair value to measure assets and liabilities. It also requires expanded disclosure regarding the extent to which fair value is used for such measurements, information used to measure fair value, and the effect of fair value measurements on earnings. Provisions of SFAS No. 157 apply whenever other accounting standards require (or permit) assets or liabilities to be measured at fair value, but does not expand the use of fair value in any new circumstances. PGE is evaluating the application of SFAS No. 157 with respect to its assets and liabilities.

SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities, was issued in February 2007 and is effective for fiscal years beginning after November 15, 2007. SFAS No. 159 provides entities the option to report most financial assets and liabilities at fair value, with changes in fair value recorded in earnings. It also establishes presentation and disclosure requirements designed to facilitate comparisons between companies that choose different measurement attributes for similar types of assets and liabilities. PGE is evaluating the application of SFAS No. 159 with respect to its assets and liabilities.

Information Regarding Forward-Looking Statements

This report contains statements that are forward-looking within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are statements of expectations, beliefs, plans, objectives, assumptions or future events or performance. Words or phrases such as "anticipates," "believes," "should," "estimates," "expects," "intends," "plans," "predicts," "projects," "will likely result," "will continue," or similar expressions identify 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 other factors and matters discussed elsewhere in this report, some important 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 investigations and actions, including those of the FERC and OPUC with respect to allowed rates of return, financings, electricity pricing and rate structures, acquisition and disposal of assets and facilities, operation and construction of plant facilities, recovery of net variable power costs and other capital investments, and present or prospective wholesale and retail competition;

- matters regarding the effects of Oregon law related to utility rate treatment of income taxes (SB 408), resulting in potential earnings volatility and adverse effects on operating results;

- events related to City of Portland, Oregon investigations with regard to rates charged by the Company, and any attempt by the City of Portland to set rates for PGE customers located within the City of Portland;

- changes in weather, hydroelectric, and energy market conditions, which could affect PGE's ability and cost to procure adequate supplies of fuel or purchased power to serve its customers;

- wholesale energy prices (including the effect of FERC price controls) and their effect on the availability and price of wholesale power purchases and sales in the western United States;

- the completion of major generating plants on schedule;
- the effectiveness of PGE's risk management policies and procedures and the creditworthiness of customers and counterparties;
- operational factors affecting PGE's power generation facilities;
- increasing national and international concerns regarding global warming and proposed regulations that could result in requirements for additional pollution control equipment or significant emissions fees or taxes, particularly with respect to coal-fired generation facilities, to mitigate carbon dioxide and other gas emissions, including regional haze and mercury emissions affecting the Company's thermal generating plants;
- changes in, and compliance with, environmental and endangered species laws and policies;
- financial or regulatory accounting principles or policies imposed by governing bodies;
- residential, commercial, and industrial growth and demographic patterns in PGE's service territory;
- the loss of any significant customer, or changes in the business of a major customer, that may result in changes in demand for PGE services;
- the ability of PGE to access the capital markets to support requirements for working capital, construction costs, and the repayment of maturing debt;
- capital market conditions, including interest rate fluctuations and capital availability;

- changes in PGE's credit ratings, which could have an impact on the availability and cost of capital;

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

- legal and regulatory proceedings and issues;

- employee workforce factors, including strikes, work stoppages, and the loss of key executives;

- general political, economic, and financial market conditions; and

- terrorist activities.

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.

Item 7A. Quantitative and Qualitative Disclosures About

Market Risk

PGE is exposed to various forms of market risk (including changes in commodity prices, foreign currency exchange rates, and interest rates), as well as to credit risk. These changes may affect the Company's future financial results, as discussed below.

Commodity Price Risk

PGE's primary business is to provide electricity to its retail customers. The Company uses purchased power contracts to supplement its thermal and hydroelectric generation to respond to fluctuations in the demand for electricity and variability in generating plant operations. In meeting these needs, PGE is exposed to market risk arising from the need to purchase power and to purchase fuel for its natural gas and coal fired generating units. 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.

Gains and losses from non-trading 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 New York Mercantile Exchange 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 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 in the non-trading portfolio. 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 non-trading portfolio in 2006 were $5.7 million, $9.9 million, and $3.3 million, respectively, and in 2005 were $3.8 million, $9.7 million, and $1.8 million, respectively.

In 2006, PGE adopted a "medium term" power cost strategy to better respond to changing energy market conditions. By extending the period in which the Company may take positions in power markets from 24 months to up to five years, PGE expects to reduce price volatility for its customers during the next three- to five-year period. Accordingly, PGE has amended its risk limits for the projected impact of the medium term strategy on the Company's net open position.

PGE's non-trading activities are subject to regulation. 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 No. 71. As contracts are settled, these deferrals reverse. In PGE's non-trading value at risk methodology, no amounts are included for potential deferrals under SFAS No. 71.

Foreign Currency Exchange Rate Risk

PGE faces exposure to foreign currency risk associated with natural gas forward and swap contracts denominated in Canadian dollars in its non-trading 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.

At December 31, 2006, 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 $400 million five-year unsecured revolving credit facility. 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. At December 31, 2006, PGE had $81 million short-term debt outstanding through the issuance of commercial paper.

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.

The total fair value and carrying amounts (including current maturities) of PGE's long-term debt are as follows (in millions):

			Carrying Amou					
	Total Fair Value		Total		2007		20	
First Mortgage Bonds	$	674	$	645	$	50	$	
Pollution Control Revenue Bonds (*)		197		194		-		
Other		175		164		16		
Total	$	1,046	$	1,003	$	66	$	

(*) Interest rates on $142 million of Pollution Control Revenue Bonds are fixed until 2009. In 2009, pursuant to terms of the bond agreements, PGE will re-market the bonds and re-set the interest rate and maturity date up to the year 2033. A 1% increase in the current interest rates would result in an approximate $1.4 million annual increase in interest expense.

For detail of debt by category, see Note 7, Credit Facility and Debt, in the Notes to Financial Statements.

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 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 following table presents PGE's credit exposure for commodity non-trading activities and their subsequent maturity as of December 31, 2006. 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):

Rating	Credit Risk Before Collateral	Percentage of Total Exposure	Credit Collateral
Investment Grade	$ 58	95%	$ 24
Non-Investment Grade	1	2%	-
Internally Rated - Investment Grade	1	2%	-
Internally Rated -	1	1	-

Non-Investment Grade		%	
Total	$ 61	100 %	$ 24

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 non-trading 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.

The large number and diversified base of residential, commercial, and industrial customers, combined with the Company's ability to discontinue service, contribute to reduced 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. At December 31, 2006, the likelihood of significant losses associated with credit risk in trade accounts receivable is remote.

Risk Management Committee

PGE has a Risk Management Committee (RMC) which is responsible for providing oversight of the adequacy and effectiveness of the 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.

For further information on price risk management activities, see Note 10, Price Risk Management, in the Notes to Financial Statements.

Item 8. Financial Statements and Supplementary Data

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders 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, 2006 and 2005, and the related consolidated statements of income, retained earnings, comprehensive income, and cash flow for each of the three years in the period ended December 31, 2006. Our audits also included the financial statement schedule listed in Item 15(a). These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Portland General Electric Company and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Notes 1 and 2 to the consolidated financial statements, on December 31, 2006, the Company changed its method of accounting for defined benefit and other postretirement plans upon the adoption of Statement of Financial Accounting Standards No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, based on the criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 1, 2007 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Deloitte & Touche LLP

Portland, Oregon

March 1, 2007

Portland General Electric Company and Subsidiaries

Consolidated Statements of Income

For the Years Ended December 31		2006		2005	
		(In Millions, except per share a			
Operating Revenues	$	1,520	$	1,446	$
Operating Expenses					
Purchased power and fuel		763		671	
Production and distribution		140		128	
Administrative and other		164		168	
Depreciation and amortization		219		233	
Taxes other than income taxes		75		74	
Income taxes		38		46	
		1,399		1,320	

Net Operating Income		121			126		
Other Income (Deductions)							
Allowance for equity funds used during construction		16			8		
Miscellaneous		1			(5	)	
Income taxes		2			3		
		19			6		
Interest Charges							
Interest on long-term debt and other		69			68		
Net Income	$	71		$	64		
Common Stock:							
Weighted-average shares outstanding							
(thousands), Basic		62,501			62,500		
Weighted-average shares outstanding							
(thousands), Diluted		62,505			62,500		
Earnings per share, Basic and Diluted	$	1.14		$	1.02		
Dividends declared per share	$	0.675		$	*		
* Not meaningful as the Company was							
a wholly-owned subsidiary of Enron.							

The accompanying notes are an integral part of these consolidated financial statemen

Portland General Electric Company and Subsidiaries

Consolidated Statements of Retained Earnings

For the Years Ended December 31		2006			2005		

		(In Millions)				
Balance at Beginning of Year	$	558	$	644		$
Net Income		71		64		
		629		708		
Dividends Declared - Common Stock		42		150		
Balance at End of Year	$	587	$	558		

The accompanying notes are an integral part of these consolidated financial stateme

Portland General Electric Company and Subsidiaries

Consolidated Statements of Comprehensive Income

For the Years Ended December 31	
Accumulated other comprehensive income (loss) - Beginning of Year	
Unrealized gain (loss) on derivatives classified as cash flow hedges	$
Minimum pension liability adjustment	
Total	$
Net Income	$
Other comprehensive income, net of tax:	
Unrealized gains (losses) on derivatives classified as cash flow hedges:	
Other unrealized holding gains arising during the period, net of related taxes of $16 in 2006, $(18) in 2005, and $(8) in 2004	
Reclassification adjustment for contract settlements included in net income, net of related taxes of $7 in 2006, $(3) in 2005, and $4 in 2004	

Reclassification adjustment in net income due to discontinuance of cash flow hedges, net of related taxes of $1 in 2005		
Reclassification of unrealized gains (losses) to SFAS No. 71 regulatory (liability) asset, net of related taxes of $(24) in 2006, $19 in 2005, and $6 in 2004		
Total - Unrealized gains (losses) on derivatives classified as cash flow hedges		
Minimum pension liability adjustment		
Total Other comprehensive income (loss)		
Comprehensive income		$
Accumulated other comprehensive income (loss) - End of Year		
Unrealized gain (loss) on derivatives classified as cash flow hedges		$
Minimum pension liability adjustment		
Pension and other postretirement plans' funded position, net of related taxes of $35		
Reclassification of defined benefit pension plan and other benefits to SFAS No. 71 regulatory asset, net of related taxes of $(33)		
Total		$

The accompanying notes are an integral part of these conso

Portland General Electric Company and Subsidiaries

Consolidated Balance Sheets

At December 31
Electric Utility Plant - Original Cost
Utility plant (includes construction work in progres $412 and $177)
Accumulated depreciation
Other Property and Investments
Nuclear decommissioning trust, at market value
Non-qualified benefit plan trust
Miscellaneous
Current Assets
Cash and cash equivalents
Accounts and notes receivable (less allowance for uncollectible accounts of $45 and $50)
Unbilled revenues
Assets from price risk management activities
Inventories, at average cost
Margin deposits
Prepayments and other
Deferred income taxes
Deferred Charges
Regulatory assets

Miscellaneous
Capitalization
Common stock equity:
Common stock, no par value, 80,000,000 s authorized; 62,504,767 and 62,500,000 shares outstanding at Dece 31, 2006 and 2005
Retained earnings
Accumulated other comprehensive income (loss):
Pension and other postretirement plans
Long-term debt
Commitments and Contingencies (see Notes)
Current Liabilities
Long-term debt due within one year
Short-term borrowings
Accounts payable and other accruals
Liabilities from price risk management activities
Customer deposits
Accrued interest
Accrued taxes
Dividends payable
Deferred income taxes

Other
Deferred income taxes
Deferred investment tax credits
Trojan asset retirement obligation
Accumulated asset retirement obligation
Regulatory liabilities:
Accumulated asset retirement removal costs
Other
Non-qualified benefit plan liabilities
Miscellaneous

The accompanying notes are an integral part of these consolidated financial statements

Portland General Electric Company and Subsidiaries

Consolidated Statements of Cash Flow

For the Years Ended December 31			2006
Cash Flows From Operating Activities:			
Reconciliation of net income to net cash provided by operating activities			
Net income		$	7
Non-cash items included in net income:			
Depreciation and amortization			219
Deferred income taxes			(38
			13

Net assets from price risk management activities			
Power cost adjustment			-
Other non-cash income and expenses (net)			26
Regulatory deferrals - price risk management activities			(132
Changes in working capital:			
Net margin deposit activity			(94
(Increase) Decrease in receivables			17
Increase (Decrease) in payables			(88
Other working capital items - net			(11
Other - net			4
Net Cash Provided by Operating Activities			106
Cash Flows From Investing Activities:			
Capital expenditures			(371
Proceeds from sale of assets			6
Purchases of nuclear decommissioning trust securities			(37
Sales of nuclear decommissioning trust securities			21
Other - net			1
Net Cash Used in Investing Activities			(380
Cash Flows From Financing Activities:			
Repayment of long-term debt			(162
Issuance of long-term debt			275
Issuance of short-term debt			81
Debt issue costs			(2
Dividends paid			(28
Net Cash Provided by (Used in) Financing Activities			164
Increase (Decrease) in Cash and Cash Equivalents			(110

Cash and Cash Equivalents, Beginning of Period			122
Cash and Cash Equivalents, End of Period		$	12
Supplemental disclosures of cash flow information			
Cash paid during the period:			
Interest, net of amounts capitalized		$	55
Income taxes			101
Non-cash investing and operating activities:			
Accrued capital additions			20

The accompanying notes are an integral part of these consolidated financial statements.

Portland General Electric Company and Subsidiaries

Notes to Consolidated Financial Statements

Nature of Operations

Portland General Electric Company (PGE, or the Company) is a single, integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the State of Oregon. The Company also sells wholesale electric energy to utilities, brokers, and power marketers located throughout the western United States. 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 service area is located entirely within Oregon and 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. At the end of 2006, PGE's service area population was approximately 1.6 million, comprising about 43% of the state's population. The Company served approximately 793,000 retail customers at December 31, 2006.

On July 2, 1997, Portland General Corporation, the former parent of PGE, merged with Enron

Corp., with Enron Corp. continuing in existence as the surviving corporation. On December 2, 2001, Enron Corp., along with certain of its subsidiaries, filed to initiate bankruptcy proceedings under Chapter 11 of the federal Bankruptcy Code. PGE was not included in the filing.

In accordance with Enron's Chapter 11 Plan, on April 3, 2006 PGE issued 62.5 million shares (of 80 million, no par value, shares authorized) of new PGE common stock. Approximately 27 million shares of the new PGE common stock were initially issued to the Debtors' creditors holding allowed claims, and approximately 35.5 million shares were issued to a Disputed Claims Reserve (DCR), where the shares will be held to be released over time to the Debtors' creditors holding allowed claims, in accordance with the Chapter 11 Plan. At December 31, 2006, approximately 32.5 million shares were held in the DCR. The 42.8 million shares of PGE common stock previously held by Enron were cancelled. Following issuance of the new PGE common stock, PGE ceased to be a subsidiary of Enron. The new PGE common stock is listed on the New York Stock Exchange under the ticker symbol POR.

Note 1 - Summary of Significant Accounting Policies

Consolidation Principles

The consolidated financial statements include the accounts of PGE and its majority-owned subsidiaries, including variable interest entities when it is the primary beneficiary with a controlling financial interest. The Company's ownership share of direct expenses and plant costs related to jointly owned generating plants are also included in the consolidated financial statements. Intercompany balances and transactions have been eliminated.

Basis of Accounting

PGE and its subsidiaries' financial statements conform to accounting principles generally accepted in the United States. In addition, PGE's accounting policies are in accordance with the requirements and the rate making practices of regulatory authorities having jurisdiction.

Use of Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at 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.

Contingencies

Contingencies are evaluated based on Statement of Financial Accounting Standards (SFAS) No. 5, Accounting for Contingencies, using the best information available. A material loss contingency is accrued and disclosed when it is probable that an asset has been impaired or a liability incurred and the amount of the loss can be reasonably estimated. If a range of 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 upon realization and are disclosed when material.

Reclassifications

Certain amounts in prior year financial statements have been reclassified for comparative purposes, as discussed below. These reclassifications had no effect on PGE's previously reported consolidated financial position, results of operations, or cash flows.

Pursuant to the April 3, 2006 issuance of new PGE common stock, the December 31, 2005 book value of the $3.75 par value common stock that was cancelled ($160 million) and the December

31, 2005 balance of Other paid-in capital - net ($482 million) have been retroactively combined in the Company's Consolidated Balance Sheets into the single new item "Common stock, no par value" ($642 million).

Prior to 2006, unrealized gains and losses on certain derivative activities that were deferred under SFAS No. 71, Accounting for the Effects of Certain Types of Regulation, to reflect the effects of regulation, were included within "Other working capital items - net" in the Operating Activities section of the Consolidated Statements of Cash Flow. Beginning in 2006, these are reflected in the separate caption "Regulatory deferrals - price risk management activities", with 2004 and 2005 amounts reclassified for comparative purposes.

Prior to 2006, amounts representing "Allowance for equity funds used during construction" were included within "Miscellaneous" under "Other Income (Deductions)" on the Consolidated Statements of Income. Beginning in 2006, such amounts are reflected in a separate caption, with 2004 and 2005 amounts reclassified for comparative purposes.

<u>Revenues</u>

Retail revenues are recognized when monthly billings are made for energy sold to customers and delivered to those customers that purchase their energy from Energy Service Suppliers (ESSs); such revenues are recorded "net" of any taxes imposed on individual revenue-producing transactions. In addition, estimated unbilled revenues are accrued for services provided to retail customers from the meter read date to month-end. Unbilled revenues are calculated based upon each month's actual net system load, the number of days from meter-reading date to month-end, and current retail customer prices. 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 probable collection of customer accounts, aging of accounts receivable, bad debt write-offs, actual customer billings, and other factors.

Wholesale revenues are recognized as energy is delivered to the Company's wholesale customers (primarily utilities and energy marketers) during the month. 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.

In certain situations, PGE defers the recognition of revenues until the period in which the related costs are incurred, in accordance with the provisions of SFAS No. 71.

Purchased Power

In addition to power purchases and certain price risk management activities (described under "Price Risk Management" in this Note), certain other activities are reflected in Purchased Power and Fuel expense. These consist of: 1) amounts related to certain power cost adjustments and deferrals; 2) amounts recorded under PGE's long-term power exchange contracts that help meet seasonal peaking requirements (for further information, see "Purchased Power" in Note 9, Commitments and Guarantees); and, 3) provisions related to wholesale accounts receivable and unsettled positions (described under "Revenues" in this Note).

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. Under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (as amended), derivative instruments are recorded on the Consolidated Balance Sheets as Assets and 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 currently in earnings unless hedge accounting applies.

Non-Trading

Certain non-trading electricity forward contracts that are 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 No. 133, as amended by SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities. Other non-trading activities consist of certain electricity forwards and natural gas forwards and swaps that qualify as cash flow hedges of forecasted transactions, and electricity options, certain electricity forwards, certain natural gas swaps and forward contracts for acquiring Canadian dollars that are classified as non-hedges. 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 Public Utility Commission of Oregon (OPUC), which regulates PGE's retail electricity business, recognizes non-trading 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 (OCI) and contracts designated as non-hedges are recorded net in Purchased Power and Fuel expense on the Statement 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 No. 71.

Prior to December 2006, PGE recorded a regulatory asset or regulatory liability under SFAS No. 71 to offset unrealized gains and losses on certain non-trading contracts recorded prior to settlement to the extent that such contracts are included in the Company's Resource Valuation Mechanism (RVM). The regulatory asset or regulatory liability is reflected within Regulatory assets or Regulatory liabilities, respectively, on the Consolidated Balance Sheets. Upon settlement, the regulatory asset or regulatory liability is reversed. In its January 2007 general rate order, the OPUC approved a new Power Cost Adjustment Mechanism (PCAM) by which PGE can adjust future rates to reflect the difference between each year's forecasted and actual net variable power costs on a settlement basis. As a result, a regulatory asset or regulatory liability is recorded to offset changes in fair value of derivative instruments not included in the RVM. Effective January 17, 2007, a new Annual Power Cost Update Tariff replaced the RVM.

Sales and purchases involving non-trading electricity derivative activities that are physically settled are recorded in Operating Revenues and Purchased Power and Fuel expense, respectively. Non-trading electricity derivative activities that are "booked out" (not physically settled) are recorded on a net basis in Purchased Power and Fuel expense, pursuant to the requirements of Emerging Issues Task Force Issue (EITF) No. 03-11.

Trading

PGE discontinued its energy trading activities for non-retail purposes in early 2005, with remaining transactions settled by December 31, 2005. Realized and unrealized gains and losses associated with such activities are reported on a net basis for all periods presented in accordance with EITF 02-3, Accounting for Contracts Involved in Energy Trading and Risk Management Activities, and are included within Operating Revenues on the Statement of Income.

For further information, see Note 10, Price Risk Management.

Customer Deposits

In the course of its wholesale activities, PGE both receives and deposits performance assurance cash collateral, with required amounts based upon provisions contained in certain wholesale power agreements with counterparties. Amounts deposited with, or received from, counterparties under such agreements are reflected as Margin deposits and Customer deposits, respectively, within the Current Assets and Current Liabilities sections of the Consolidated Balance Sheets. Also included within Current Liabilities are credit deposits received from certain retail and transmission customers.

Capitalization of Property, Plant and Equipment

Additions to utility plant are capitalized at their original cost, consistent with accounting and regulatory guidelines. 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. Plant replacements are capitalized, with minor items charged to expense as incurred. The costs to purchase/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 relicensing the Company's hydroelectric projects are capitalized and amortized over the related license period.

Utility plant at December 31 consists of the following (in millions):

		2006		2005
Production	$	1,414	$	1,395
Transmission		283		278
Distribution		2,059		1,959
General		242		239
Intangible		172		176
Construction Work in Progress		412		177

Total	$	4,582		$	4,224

Depreciation and Amortization of Property, Plant and Equipment

Depreciation is computed using the straight-line method over the estimated average service lives of various classes of plant in service. Classes of plant in service and their estimated service lives (in years) are as follows: Production (33), Transmission (55), Distribution (35), and General (13). Depreciation is 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 4.3% in 2006, 4.4% in 2005, and 4.5% in 2004. Estimated asset retirement removal costs included in depreciation expense were $68 million, $64 million, and $61 million in 2006, 2005, and 2004, 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 stipulated to in October 2006, and are incorporated into customer rates that became effective on January 17, 2007.

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 asset retirement obligations for assets with AROs and to accumulated asset retirement removal costs for assets without AROs. See Note 12, Asset Retirement Obligations, for further information.

Intangible plant consists primarily of computer software development costs, which are amortized over either five or ten years, and hydro re-licensing costs, which are amortized over the applicable license term. Amortization expense for 2006, 2005, and 2004, was $15 million, $13 million, and $14 million, respectively, and is estimated at $15 million for 2007, $11 million for 2008, 2009, and 2010, and $10 million in 2011. Accumulated amortization was $82 million and $76 million at December 31, 2006 and December 31, 2005, respectively; the increase consists of the net amount of current year amortization expense less accumulated amortization on intangible plant retirements.

Major Maintenance Expenses

Costs of periodic major maintenance inspections and overhauls at the Company's generating plants are charged to operating expenses as incurred. PGE's retail customer rates include the recovery of an annual amount, authorized by the OPUC, for estimated major maintenance expenses incurred at the Company's Coyote Springs combustion turbine generating plant. Differences between amounts authorized in rates and actual expenses incurred are deferred as regulatory assets or regulatory liabilities pursuant to SFAS No. 71.

Allocations and Loadings

PGE utilizes a series of cost distributions and loadings to allocate certain administrative and overhead costs between capital and operating accounts, based primarily on construction activities of the Company.

Allowance for Funds Used During Construction (AFDC)

AFDC represents the pre-tax cost of borrowed funds used for construction purposes and a reasonable rate for equity funds. It is capitalized as part of the cost of plant and is credited to income but does not represent current cash earnings. The average rates used by PGE in 2006, 2005, and 2004 were 9.0%. AFDC from borrowed funds was $8 million in 2006, $4 million in 2005, and $3 million in 2004. AFDC from equity funds was $16 million in 2006, $8 million in 2005, and $6 million in 2004.

Debt Issuance Costs

Underwriting, legal, and other direct costs related to the issuance of debt securities are deferred and amortized to interest expense equitably over the life of the security. Unamortized debt issuance costs at December 31, 2006 and 2005 were $15 million and $16 million, respectively, and are classified within Deferred charges - Miscellaneous on the Consolidated Balance Sheets.

Income Taxes

PGE files consolidated federal and state income tax returns. The Company's policy is to collect for tax liabilities from subsidiaries that generate taxable income and to reimburse subsidiaries for tax benefits utilized in its tax return. Deferred income taxes are provided for temporary differences between financial and income tax reporting. Investment tax credits utilized have been deferred and are amortized to income over the approximate lives of the related properties. See Note 3, Income Taxes, for further information.

PGE's federal taxable income was included in Enron's consolidated federal income tax return from July 2, 1997 through April 2, 2006, with the exception of the period May 8, 2001 through December 23, 2002, during which PGE and its subsidiaries filed their own consolidated tax returns. Upon issuance of new PGE common stock on April 3, 2006, PGE and its subsidiaries are no longer included in Enron's consolidated return. For further information, see Note 17, Related Party Transactions.

Cash and Cash Equivalents

Highly liquid investments with maturities of three months or less at the date of acquisition are classified as cash equivalents.

Non-Qualified Benefit Plan Trust

The non-qualified benefit plan trust is comprised of insurance contracts and investments in money market, bond, and other equity investments. The cash surrender value of insurance contracts is reported as an asset at the end of the reporting period, with changes in such values between reporting periods recognized as income or expense of the period (see "Other Non-Qualified Benefit Plans" in Note 2, Employee Benefits, for further information). The cash surrender value of insurance contracts, the majority of which are held in the trust, was $23 million at December 31, 2006 and $22 million at December 31, 2005. The investments in marketable securities are classified as trading and recorded at fair value on the Consolidated Balance Sheets. Realized and unrealized gains and losses on these investments (determined using average cost) are included in Other Income (Deductions) on the Consolidated Statements of Income. Investments in marketable securities and cash totaled $47 million at both December 31, 2006 and 2005.

Inventories

PGE's inventories are recorded at cost, which includes the purchase price (less discounts), applicable taxes, transportation and handling, etc. The average cost method is utilized to price inventory as fuel is burned at the generating plants and as materials and supplies are issued for operations, maintenance and capital activities. General storeroom operation costs, including procurement, management, and storage, are recorded in the unallocated stores account and distributed equitably as materials and supplies are issued.

Inventories at December 31 are summarized as follows (in millions):

	2006		2005	
Coal	$	20	$	11
Fuel oil		10		11
Natural gas		3		4
		28		25

Materials and supplies							
Unallocated stores account		3				3	
Total	$	64			$	54	

Trojan Decommissioning Costs

Trojan decommissioning costs consist of those expenditures related to the decommissioning of the Trojan Nuclear Plant. The present value of estimated future decommissioning expenditures, which is revised periodically, is recorded as an ARO on the Consolidated Balance Sheets, with actual expenditures charged to the ARO account as incurred. See Note 12, Asset Retirement Obligations, and Note 13, Trojan Nuclear Plant, for further information.

Regulatory Assets and Liabilities

PGE is subject to the provisions of SFAS No. 71. Accounting under SFAS No. 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.

When the requirements of SFAS No. 71 are met at the date the costs are incurred, or at a later date when evidence supports cost deferral (e.g. an OPUC deferred accounting order), the Company defers certain costs which would otherwise be charged to expense if it is probable that future prices will permit recovery of such costs. In addition, PGE defers certain revenues, gains, or cost reductions which would normally be reflected in income but through the rate making process will ultimately be refunded to customers. Regulatory assets and liabilities are reflected within Deferred Charges and Other on the Consolidated Balance Sheets and are amortized over the period in which they are included in billings to customers. If at some point in the future PGE determines that all or a portion of the utility operations no longer meets the criteria for continued application of SFAS No. 71, PGE could be required to write-off its regulatory assets.

Amounts in the Consolidated Balance Sheets as of December 31 consist of the following (in millions):

	2006	2005
Regulatory assets:		
Trojan decommissioning costs	$ 66	$
Income taxes recoverable	74	
Debt reacquisition costs	30	
Conservation investments - secured	-	
Boardman power cost deferral	6	
Pension and other postretirement plans	87	
Regulatory restructuring costs (1)	11	
Price risk management	62	
Beaver 8 (1)	7	
Miscellaneous (2)	8	
Total	$ 351	$
Regulatory liabilities:		
Asset retirement obligations	$ 27	$
Accumulated asset retirement removal costs	411	
	-	

	Price risk management							
	Information technology costs (1)			3				
	Trojan ISFSI pollution control tax credits (1)			10				
	Oregon corporation excise tax refund (1)			4				
	Residential Exchange Program (1)			14				
	Oregon Senate Bill 408 (SB 408)(1)			42				
	Miscellaneous (3)			12				
Total			$	523				$

1. A return on the unamortized balance of these items is recorded at PGE's authorized cost of capital (9.083% through 2006 and 8.29% beginning on January 17, 2007).

2. Of the total miscellaneous unamortized balances, a return is recorded on $3 million at both December 31, 2006 and December 31, 2005 at PGE's authorized cost of capital, as indicated in (1) above.

3. Of the total miscellaneous unamortized balances, a return is recorded on $6 million at December 31, 2006 and $7 million at December 31, 2005 at PGE's authorized cost of capital, as indicated in (1) above.

Trojan decommissioning costs -

PGE's retail prices include recovery of costs to decommission Trojan (see Note 13, Trojan Nuclear Plant, for further information). These amounts represent the estimated fair value of the remaining decommissioning costs to be recovered from customers.

Income taxes recoverable -

The amount represents tax benefits previously flowed to customers through rates for temporary differences between book and tax reporting. The balance is reduced as temporary differences reverse and the increase in current tax expense is recovered in customer rates.

Debt reacquisition costs -

As authorized by the OPUC, costs related to the reacquisition of debt securities, including unamortized debt issuance costs related to such debt securities, are deferred and amortized to interest expense equitably over the life of the replacement or retired issue as applicable.

Conservation investments - secured

- In 1996, $81 million of PGE's energy efficiency investment was designated as Bondable Conservation Investment upon the Company's issuance of 10-year 6.91% conservation bonds collateralized by OPUC-authorized revenues, which funded the debt service obligation. The issuance of such bonds provided PGE immediate recovery of its unamortized energy efficiency program expenditures while providing future savings to customers. These bonds were paid in October 2006.

Boardman power cost deferral -

In October 2005, the Boardman Coal Plant (Boardman) was taken out of service for repair of the plant's steam turbine rotor and remained out of service during the first half of 2006 for additional repairs. PGE incurred significant incremental power costs during this period to replace the plant's generation. In November 2005, PGE filed with the OPUC an application to defer for later ratemaking treatment excess power costs associated with Boardman's turbine rotor repair outage. Based upon prior OPUC actions, the stated position of the OPUC staff in the proceeding, and considering both applicable accounting guidance and the impact of SB 408 on any benefit received by the Company, PGE recorded a deferral in the amount of $6 million at December 31, 2006. See Note 18, Subsequent

Event, for further information.

Pension and other postretirement plans

- On December 31, 2006, PGE adopted SFAS No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, which requires that the funded status of pension and other postretirement plans be recognized, with the resulting adjustment recorded to the ending balance of Accumulated OCI on the Consolidated Balance Sheets. Postretirement costs are covered in rates charged to customers through 2006. The OPUC issued an accounting order that authorizes PGE to record a regulatory asset equal to the pretax charge against Accumulated OCI that would otherwise be required by recognition of the pension funded status under SFAS No. 158. As pension expense is recognized in future years, the regulatory asset will be reduced. See Note 2, Employee Benefits, for further information.

Regulatory restructuring costs

- The OPUC authorized PGE to defer certain costs related to implementation of Oregon's electric restructuring law. Approximately $24 million is currently being recovered in prices charged to customers, with a remaining balance of $11 million at December 31, 2006. Of the $24 million total implementation costs, $7 million is being recovered over a five-year period that began on January 1, 2003, with a remaining balance of $2 million at December 31, 2006, and $17 million is being recovered over a five-year period that began on January 1, 2004, with a remaining balance of $9 million at December 31, 2006.

Price risk management -

SFAS No. 133 requires unrealized gains and losses on derivative instruments that do not qualify for the normal purchase and normal sale exception to be recorded in earnings and other comprehensive income in the current period. To reflect the effects of regulation under SFAS No. 71, timing differences between the recognition of unrealized gains and losses on non-trading derivative instruments and their realization and subsequent recovery in rates are recorded as regulatory assets or regulatory liabilities.

Amounts recorded by PGE at December 31, 2006 and 2005 offset the effects of such gains and losses, which are caused by changes in fair values of related energy contracts; recorded amounts are reversed as such contracts are settled. See Note 10, Price Risk Management, for further information.

Beaver 8 -

In December 2004, the OPUC issued an Order that adopted a stipulation in which parties agreed that PGE may recover from customers approximately $14 million for costs associated with a 24.7 MW combustion turbine (referred to as Beaver 8) installed at the Company's Beaver generating plant site in 2001. Of this amount, $10 million (plus accrued interest) was deferred for recovery from customers over a five-year period beginning January 1, 2005. The remaining $4 million, representing the current market value of the turbine, remains in plant in service and is depreciated over its useful life.

Asset retirement obligations -

SFAS No. 143, Accounting for Asset Retirement Obligations requires the recognition of 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. Pursuant to regulation, AROs of rate-regulated long-lived assets are included as an allowable cost in rates 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 No. 71. Asset retirement obligations are included in PGE's rate base for ratemaking purposes.

Accumulated asset retirement removal costs -

Asset retirement removal costs that do not qualify as AROs are a component of depreciation expense allowed in customer rates. Accumulated asset retirement removal costs are recorded as a regulatory liability as they are collected in rates, and are reduced by actual removal costs as incurred, in accordance with SFAS No. 143 and SFAS No. 71. This amount is also included as a reduction to PGE's rate base for ratemaking purposes.

Information technology costs

- In PGE's 2001 general rate filing, the OPUC approved an estimated amount of capital expenditures related to the Company's Customer Information System (CIS) and Information Technology (IT) activities in the determination of PGE's 2002 revenue requirement. The OPUC's rate order stipulated that PGE's retail customers are to receive a refund if the actual revenue requirement for such costs is less than the estimated revenue requirement. Accordingly, regulatory liabilities of $4 million were recorded from 2003 through 2006 to reflect the difference between actual and estimated revenue requirements related to CIS and IT capital expenditures. Amounts that were deferred are being refunded to customers through 2007.

Trojan ISFSI pollution control tax credits

- In December 2004, PGE received final certification from the Oregon Environmental Quality Commission (OEQC) related to $21.1 million in Oregon pollution control tax credits that were generated from PGE's investment in an Independent Spent Fuel Storage Installation (ISFSI) at Trojan. OEQC rules require that the tax credits be spread over a ten-year period, beginning in 2004. The OPUC approved the deferral of the tax credits for future ratemaking treatment. See Note 13, Trojan Nuclear Plant, for further information.

Oregon corporation excise tax refund

- Oregon's constitution provides for a Corporation Excise Tax refund when actual state tax revenues exceed those estimated in the state's budget. In 2005, PGE received a tax credit related to the difference between estimated and actual state excise taxes collected during the state's 2003-2005 biennium, with such refund reflected as a credit against the Company's net 2005 tax liability. PGE's share of the state tax credit is being deferred for future refund to customers.

Residential Exchange Program

- The Residential Exchange Program, which is administered by the Bonneville Power Administration (BPA), provides access to the benefits of federal power to residential and small farm customers of the region's investor-owned utilities. In 2000, PGE entered into a settlement agreement with the BPA related to the Residential Exchange Program covering the period October 1, 2001 through September 30, 2011. The benefits that PGE receives under the agreement with the BPA are passed through directly to residential and small farm customers in the form of monthly billing credits. The $14 million balance in the regulatory liability represents those benefits received by PGE that have not yet been passed through to eligible customers at December 31, 2006.

SB 408 -

This Oregon 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 investor-owned utilities or their consolidated group. Based on PGE's assessment of rules issued by the OPUC in September 2006, the Company has established a reserve of $42 million (including $2 million in interest) for potential future refunds to customers. Under the law, any refunds to customers would begin after June 1, 2008. For further information, see Note 16, Utility Rate Treatment of Income Taxes.

Recovery/refund period -

As of December 31, 2006, the majority of PGE's regulatory assets and liabilities are reflected in customer rates. Based on such rates, PGE estimates that it will collect substantially all of is regulatory assets, and refund its regulatory liabilities (excluding those related to asset retirement obligations and removal costs), within the next 13 years.

<u>New Accounting Standards</u>

SFAS No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, was issued in September 2006. SFAS No. 158 requires an employer to recognize in its statement of financial position an asset for a plan's overfunded status or a liability for a plan's underfunded status, measure a plan's assets and its obligations that determine its funded status as of the end of the employer's fiscal year, and recognize changes in the funded status of a defined benefit postretirement plan in the year in which the changes occur. The requirement to recognize the funded status of a benefit plan and the disclosure requirements are effective as of the end of the fiscal year ending after December 15, 2006. PGE adopted SFAS No. 158 at December 31, 2006. For further information, see Note 2, Employee Benefits.

SEC Staff Accounting Bulletin No. 108 (SAB 108), Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements, was issued in September 2006 and is effective for fiscal years ending after November 15, 2006. In addressing the current diversity of practice, SAB 108 provides interpretive guidance on how misstatements should be quantified and requires use of a "dual approach" method when evaluating the materiality of financial statement errors. Such approach requires consideration of the impact of misstatements on both the income statement ("rollover" method) and balance sheet ("iron curtain" method). If such consideration, along with the evaluation of all relevant quantitative and qualitative factors, results in quantifying a misstatement as material, adjustment of financial statements is required. The application of SAB 108 did not have a material effect on the financial statements of the Company.

FASB Interpretation No. 48 (FIN 48), Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109, was issued in July 2006 and is effective for annual reporting periods beginning after December 15, 2006. FIN 48 seeks to reduce the diversity in practice associated with certain aspects of the recognition and measurement requirements related to accounting for income taxes. It requires that a tax position meet a "more-likely-than-not" threshold for the benefit of an uncertain tax position to be recognized in the financial statements. FIN 48 requires recognition in the financial statements of the best estimate of the effects of a tax position only if that position is more likely than not of being sustained on audit by the appropriate taxing authorities, based solely on the technical merits of the position. Based upon an assessment of the application of FIN 48 with respect to PGE's income taxes, the adoption of FIN 48 is not expected to have a material effect on the financial statements of the Company.

SFAS No. 157, Fair Value Measurements, was issued in September 2006 and is effective for fiscal years beginning after November 15, 2007. SFAS No. 157 provides enhanced guidance for the use of fair value to measure assets and liabilities. It also requires expanded disclosure regarding the extent to which fair value is used for such measurements, information used to measure fair value, and the effect of fair value measurements on earnings. Provisions of SFAS No. 157 apply whenever other accounting standards require (or permit) assets or liabilities to be measured at fair value, but does not expand the use of fair value in any new circumstances. PGE is evaluating the application of SFAS No. 157 with respect to its assets and liabilities.

SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities, was issued in February 2007 and is effective for fiscal years beginning after November 15, 2007. SFAS No. 159 provides entities the option to report most financial assets and liabilities at fair value, with changes in fair value recorded in earnings. It also establishes presentation and disclosure requirements designed to facilitate comparisons between companies that choose different measurement attributes for similar types of assets and liabilities. PGE is evaluating the application of SFAS No. 159 with respect to its assets and liabilities.

Note 2 - Employee Benefits

Pension and Other Post-Retirement Plans

Defined Benefit Pension Plan -

PGE sponsors a non-contributory defined benefit pension plan, of which substantially all members are current or former PGE employees. The assets of the pension plan are held in a trust. Pension plan calculations include several assumptions which are reviewed annually with PGE's consulting actuaries and trust investment consultants and are updated as appropriate. In 2005, PGE updated the mortality rate assumption used for the pension plan, which resulted in a $14 million increase in the accumulated benefit obligation included in the accompanying table.

In August 2005, PGE transferred $3 million in pension assets from PGE's pension plan to Enron Corp.'s Cash Balance Plan to reflect a net exchange of assets and benefit obligations. These exchanges consolidated benefits for certain individuals who had changed employers and as a result had ceased earning benefits under one plan and began earning benefits under the other plan. The transfer is included in "Divestitures" in the accompanying table.

In December 2005, PGE made a $10 million cash contribution to the pension plan. No contributions were made in 2006 and the Company does not currently expect to make a contribution to the pension plan in 2007. The measurement date for the pension plan is December 31.

Non-Qualified Benefit Plans -

The Non-Qualified Benefit Plans in the accompanying table primarily represent obligations for a Supplemental Executive Retirement Plan (SERP). The SERP was closed to new participants in 1997. Investments in a non-qualified benefit plan trust, consisting of trust owned life insurance policies (TOLI) and marketable securities, are intended to be the primary source for financing these plans. Trust assets of $25 million as of December 31, 2006 and $24 million as of December 31, 2005 are shown in the accompanying table for informational purposes only and are not considered segregated and restricted as defined by SFAS No. 158, Employers' Accounting for Defined Benefit Pension and Other Post Retirement Plans. The investments in marketable securities, consisting of money market, bond, and equity mutual funds, are classified as trading and recorded at fair value. Unrealized gains in marketable securities were $2 million for 2006 and $1 million for each of the years 2005 and 2004. In addition, recognized gains on trust assets of $1 million for each of the years 2006, 2005 and 2004 are included in net periodic benefit cost. Realized gains and losses on marketable securities are computed utilizing the average cost of such securities. The measurement date for the non-qualified plans is December 31.

In April 2005, PGE assumed $2 million of non-qualified benefits plan liabilities from Portland General Holdings, Inc. (PGH) as part of a settlement with certain PGH participants. PGE also received $2 million in trust assets to be used for the payment of benefits. These amounts are included in "Assumed plans" in the accompanying table.

Other Benefits -

PGE also participates in non-contributory post-retirement health and life insurance plans ("Other Benefits" in the table). 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. Post-retirement benefit plan calculations include several assumptions which are reviewed annually with PGE's consulting actuaries and trust investment consultants and updated as appropriate. In 2005, PGE updated the mortality rate assumption used for the post-retirement benefits. The impact of this change on the benefit obligation was not significant.

PGE has also established Health Retirement Accounts (HRAs) for its employees. Contributions are made to trust accounts to provide for claims by retirees for qualified medical costs. The 2004 bargaining unit agreement provides that retired employees may submit claims to the HRA for qualified medical expenses up to 58% of the value of any accumulated sick time at their retirement. The Company also granted a fixed dollar amount for all active non-bargaining employees, which will become available for qualified medical expenses upon their retirement.

No contributions were made to the post-retirement or non-bargaining HRA plans in 2006. Contributions totaling $1 million were made to the bargaining unit HRA in 2006. Contributions to the bargaining unit HRA are expected to be minimal in 2007. No contributions are currently expected to be made to the other post-retirement plans in 2007. The measurement date for the post-retirement plans is December 31.

SFAS No. 158

- SFAS No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, requires an employer to recognize in its statement of financial position an asset for a plan's overfunded status or a liability for a plan's underfunded status, measure a plan's assets and its obligations that determine its funded status as of the end of the employer's fiscal year, and recognize changes in the funded status of a defined benefit postretirement plan in the year in which the changes occur.

PGE adopted SFAS No. 158 as of December 31, 2006. Upon adoption, PGE recorded a pre-tax adjustment of $93 million to the ending balance of Accumulated OCI. The adjustment to Accumulated OCI consisted of $82 million of unrecognized actuarial losses, $10 million of unrecognized prior service costs, and $1 million of unrecognized transition obligations. PGE subsequently recorded an offsetting adjustment of $87 million to a regulatory asset under SFAS No. 71. As a result of adopting SFAS No. 158, the Consolidated Balance Sheets changed as follows (in millions):

Balance Sheet Line Item:			Balances prior t adoption of SFAS No. 158
Regulatory assets		$	
Deferred charges - Miscellaneous			84

Accounts payable and other accruals	
Non-qualified benefit plan liabilities	21
Other liabilities - miscellaneous	15
Deferred income taxes	1
Accumulated OCI (pre-tax)	(3

The following table provides a reconciliation of changes in the Plans' benefit obligations and fair value of assets, a statement of the funded status, and components of net periodic benefit cost (dollars in millions):

	Defined Benefi Pension Plan			
	2006		20	
Reconciliation of benefit obligation:				
Obligation at January 1	$	483	$	
Service cost		13		
Interest cost		27		
Assumed plans		-		
Divestitures		-		
Participants' contributions		-		
Actuarial (gain) loss		(6)		
Benefit payments		(25)		
Obligation at December 31	$	492	$	
Reconciliation of fair value of				

plan assets:			
Fair value of plan assets at January 1	$	469	$
Actual return on plan assets		59	
Company contributions		-	
Assumed plans		-	
Participants' contributions		-	
Divestitures		-	
Benefit payments		(25)	
Fair value of plan assets at December 31	$	503	$
Funded status:			
Funded (unfunded) status at December 31	$	11	$
Unrecognized transition liability		*	
Unrecognized prior service cost		*	
Unrecognized loss		*	
Prepaid pension asset (liability)	$	11	$
Accumulated benefit obligation at December 31	$	436	$
Amounts recognized in the Consolidated Balance Sheets consist of:			
Noncurrent asset	$	11	$

Current liability		-			
Noncurrent liability		-			
Prepaid benefit cost (liability)		*			
Accumulated other comprehensive income		*			
Net amount recognized	$	11		$	

(*) With the adoption of SFAS No. 158 at Decemb
Similarly, certain information for 2006 was not pre

Amounts recognized in accumulated other comprehensive income consist of:					
Net actuarial loss/(gain)	$	69		$	
Prior service cost/(credit)		4			
Transition obligation/(asset)		-			
Net amount recognized	$	73	(a)	$	
Assumptions:					
Discount rate used to calculate benefit obligation		5.75	%		5
Weighted average rate of increase in future compensation levels		4.44	%		4
Long-term rate of return on assets		9.00	%		9

(a) Subsequently transferred to Regulatory Assets.

	Defined Benefit Pension Plan			
	2006	2005	2004	200

Components of net periodic benefit cost:				
Service cost	$ 13	$ 12	$ 12	$
Interest cost on benefit obligation	27	25	24	
Expected return on plan assets	(41)	(41)	(40)	
Amortization of transition asset	-	-	(2)	
Amortization of prior service cost	1	2	2	
Recognized (gain) loss	4	2	-	(
Net periodic benefit cost (income)	$ 4	$ -	$ (4)	$

The estimated amounts that will be amortized from Accumulated OCI into net periodic benefit cost in 2007 are as follows (in millions):

	Pension Benefits	Non-qualified Benefits	C Be
Actuarial (gain)/loss	$ 4	$ 1	
Prior service (credit)/cost	1	-	
Transition (asset)/obligation	-	-	
Total	$ 5	$ 1	

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):

	Paymer		
	2007	2008	2009
Pension Plan Payments	$ 25	$ 25	$ 25
Non-Qualified Plan Payments	2	2	1
Other Plan Payments	4	4	4
Total	$ 31	$ 31	$ 30

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 8.5% annual rate of increase in the per capita cost of covered health care benefits is assumed for 2007. The rate is assumed to decrease to 5% by 2014 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 change in assumed health care cost trend rates would have the following effects (in millions):

		One-Percentage Point Increase		
Effect on total of service and interest cost components		$ -		
Effect on post-retirement benefit obligation		$ 1		

The asset allocation for the pension plan at December 31, 2006 and 2005, and the target allocation for 2007, are as follows:

Asset Category		Percentage of Plan Assets December 31				Target A	
		2006		2005			2
Equity Securities		67%		67%			
Debt Securities		33%		33%			
Total		100%		100%			1

The asset allocation for the Non-Qualified Benefit Plans at December 31, 2006 and 2005, and the target allocation for 2007, are as follows:

Asset Category		Percentage of Plan Assets December 31				Target A	
		2006		2005			2
Cash Equivalents		1%		10%			
Debt Securities		11%		7%			
Equity Securities		42%		37%			
TOLI Policies		46%		46%			
Total		100%		100%			1

An insurable interest in the respective employees is required for investment in TOLI policies. PGE does not establish target allocations between the TOLI assets and the remaining investments.

The asset allocation for the Other Benefit Plans at December 31, 2006 and 2005, and the target allocation for 2007, are as follows:

Asset Category		Percentage of Plan Assets December 31					Target A
		2006		2005			2
Equity Securities		62%		68%			6
Debt Securities		38%		32%			3
Total		100%		100%			10

The Plans' investment policies call for permanent commitment to five asset classes to promote diversification at the plan level. The commitments to each class are controlled by an Asset Deployment Policy and Cash Management Policy that take 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.

Other Non-Qualified Benefit Plans

In addition to the SERP discussed above, PGE provides certain employees with benefits under unfunded management deferred compensation plans (MDCPs), whereby participants may defer a portion of their pay. Obligations for the MDCPs were $56 million and $54 million at December 31, 2006 and 2005, respectively (not included in table). The costs of the SERP and MDCPs are excluded from prices charged to customers. Investments in trust owned life insurance policies and marketable securities are intended to be the primary source for financing the MDCPs. Total assets held in support of the

MDCP Plan were $40 million at December 31, 2006 and $39 million at December 31, 2005. Unrealized gains in marketable securities were $4 million for 2006 and $1 million for 2005 and 2004.

PGE sponsors additional non-qualified plans for certain employees and former directors. Obligations for these plans are minimal. Assets held in support of these plans totaled $1 million at December 31, 2006 and $2 million at December 31, 2005.

In April 2005, PGE assumed $5 million of management deferred compensation plan and directors deferred compensation plan liabilities from PGH as part of a settlement with certain PGH participants. PGE also received $5 million in trust assets to be used for payment of benefits. Obligations for the PGH liabilities were $4 million at December 31, 2006 and 2005. Total trust assets held in support of the PGH liabilities were also $4 million at December 31, 2006 and 2005.

<u>401(k) Retirement Savings Plan</u>

PGE participated in the Enron Corp. Savings Plan during 2004. At the end of 2004, employee balances were transferred from the Enron Corp. Savings Plan to a new 401(k) Plan sponsored by PGE, which became effective on January 1, 2005. Contribution provisions, described below, did not change.

Contributions to the 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 unit employees, contributions up to 6% of base pay are matched by the Company.

For bargaining unit 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 plan are invested in accordance with employees' individual investment choices. PGE made matching contributions to its employees' savings plan accounts of approximately $13 million in 2006, $13 million in 2005, and $12 million in 2004.

Note 3 - Income Taxes

The following table indicates the detail of taxes on income and the items used in computing the differences between the statutory federal income tax rate and PGE's effective tax rate (dollars in millions):

	2006	2005	
Income Tax Expense			
Current:			
Federal	$ 66	$ 88	$
State and local	8	8	
	74	96	
Deferred:			
Federal	(29)	(41)	
State and local	(6)	(9)	
	(35)	(50)	
Investment tax credit adjustments	(3)	(3)	
Total income tax expense	$ 36	$ 43	$
Income tax expense allocated to:			
Operations	$ 38	$ 46	$
Other income and deductions	(2)	(3)	

Total income tax expense	$	36		$	43		$
Effective Tax Rate Computation:							
Computed tax based on statutory federal income tax rate (35%) applied to income before income taxes	$	38		$	37		$
Flow through depreciation		5			7		
State and local taxes - net of federal tax benefit		2			1		
Investment tax credits		(3	)		(3	)	
Excess deferred taxes		(1	)		(1	)	
Adjustments for previously-recorded taxes		(4	)		2		
Other		(1	)		-		
Total income tax expense	$	36		$	43		$
Effective tax rate		33.5	%		39.9	%	

As of December 31, 2006 and 2005, the significant components of PGE's deferred income tax assets and liabilities were as follows (in millions):

		2006		2005
<u>Deferred income tax assets</u>				
Depreciation and amortization	$	36	$	35
Employee benefits		72		34
Allowance for uncollectible accounts		19		20
Revenue subject to refund (SB 408)		16		-
Land reclamation costs		-		3
Regulatory liabilities				

Asset retirement removal costs		163			139
Other		19			39
Other		5			17
Total deferred income tax assets		330			287
Deferred income tax liabilities					
Depreciation and amortization		457			463
Employee benefits		25			27
Property taxes		5			5
Price risk management		4			26
Regulatory assets					
Debt reacquisition costs		12			8
Conservation investments		-			3
Energy efficiency programs		-			4
Pension		34			-
Miscellaneous		9			11
Other		13			9
Total deferred income tax liabilities		559			556
Net deferred income taxes	$	229		$	269
Classification of net deferred income taxes					
Included in current (assets) liabilities	$	(22	)	$	51
Included in non current liabilities		251			218

Net deferred income taxes	$	229	$	269

PGE has recorded deferred tax assets and liabilities for all temporary differences between the financial statement basis and tax basis of assets and liabilities.

Note 4 - Common and Preferred Stock

Common Stock

(Dollars in Millions)	Number of Shares	$3.75 Par Value	No Par Valu
December 31, 2004	62,500,000	-	$ 64
December 31, 2005	62,500,000	-	
December 31, 2006	62,504,767	-	

Common Stock Issuance

In accordance with Enron's Chapter 11 Plan, on April 3, 2006 PGE issued 62.5 million shares (of 80 million, no par value, shares authorized) of new PGE common stock. Approximately 27 million shares of the new PGE common stock were initially issued to the Debtors' creditors holding allowed claims, and approximately 35.5 million shares were issued to the DCR, where the shares will be held to be released over time to the Debtors' creditors holding allowed claims, in accordance with the Chapter 11 Plan. As of December 31, 2006, approximately 3 million shares of PGE common stock had been released from the DCR, with approximately 32.5 million shares remaining in the DCR. The 42.8 million shares of PGE common stock previously held by Enron were cancelled.

PGE accounted for the stock issuance in the same manner as a stock split and has retroactively adjusted all periods presented. The Company's Consolidated Balance Sheets reflect the combined book values of the $3.75 par value common stock that was cancelled and other paid-in capital into the new item "Common stock, no par value." PGE's Consolidated Statements of Income reflects "Earnings per Average Share" for both current and prior periods, with such amounts based upon the number of outstanding shares of new PGE common stock. Costs incurred for the issuance of new common stock, and for PGE to become a publicly-traded company, were charged to operating expense as incurred.

In addition to the issuance of the 62.5 million shares of new PGE common stock described above, approximately 4.7 million shares have been registered for future issuance pursuant to the Portland General Electric Company 2006 Stock Incentive Plan. For further information regarding PGE's Stock Incentive Plan, see Note 5, Stock-Based Compensation.

Common Stock Dividend Restriction

The OPUC order approving the issuance of new PGE common stock includes a stipulation containing several conditions, including a requirement that, after issuance of the new common stock, PGE cannot pay a dividend that would reduce the Company's common equity capital percentage below 48% of total capitalization (excluding short-term borrowings) without prior OPUC approval. The requirement is reduced to 45% when the DCR holds between 20% and 40% of the issued and outstanding common stock of PGE, with no minimum common equity capital percentage requirement when the DCR holds less than 20% of the outstanding common stock of PGE. At December 31, 2006, the DCR held approximately 52% of the total issued and outstanding common stock of PGE. Other conditions include a requirement that the OPUC be notified (simultaneously with the public) of any dividend declared by PGE's Board of Directors.

Limited Voting Junior Preferred Stock

On March 28, 2006, the $1.00 par value Limited Voting Junior Preferred Stock was redeemed and cancelled and will not be reissued.

Note 5 - Stock-Based Compensation

On July 13, 2006, PGE granted restricted stock units (Stock Units) with time-based vesting conditions (Restricted Stock Units) and performance-based vesting conditions (Performance Stock Units) to non-employee members of the Company's Board of Directors, officers, and certain key employees. Each Stock Unit represents the right to receive one share of the Company's common stock at a future date, subject to applicable vesting requirements. The grants were made pursuant to the terms of the Portland General Electric Company 2006 Stock Incentive Plan, and are subject to the terms and conditions of the plan and individual award agreements between the Company and each grantee. A total of 4,687,500 shares of common stock was registered for future issuance under the plan.

The eight non-employee directors on the Board on July 13, 2006 were initially granted a total of 9,608 Restricted Stock Units as part of their annual compensation. Each of the directors was granted 1,201 units, valued at $30,000 based upon the closing stock price on the grant date. An additional grant of 801 units, valued at $22,500, was made on November 16, 2006 to a newly elected director. The grants vest over a one-year period in equal installments on the last day of each calendar quarter and will be settled exclusively in shares of the Company's common stock, provided that the director remains a member of the Board of Directors. The non-employee director grants also provide for the quarterly payment of dividend equivalent rights (DERs) on the non-vested Restricted Stock Units. The DERs are settled in cash on the date that the related dividends are paid to holders of PGE's common stock, or the cash settlement may be deferred under terms of the Portland General Electric Company 2006 Outside Directors' Deferred Compensation Plan.

PGE also awarded a total of 88,601 Restricted Stock Units and 89,238 Performance Stock Units to officers and certain key employees of the Company. The number of Stock Units was determined by dividing a specified award amount for each grantee by the closing stock price on the grant date. Both Restricted Stock Unit and Performance Stock Unit grants provide for the payment of DERs during the vesting period, which entitle the grantee to receive an amount equal to dividends paid on a share of PGE's common stock between the grant date and the vesting date. The Performance Stock Unit DERs vest on the same schedule as the Performance Stock Units and are settled in shares of PGE common stock valued at the closing stock price on the vesting date. Restricted Stock Unit DERs are valued at each dividend payable date and vest on the same schedule as the Restricted Stock Units.

The Restricted Stock Unit grants to PGE officers provide for vesting over a three-year period in equal installments on each anniversary of the grant date. The Restricted Stock Unit grants to key employees vest at the end of the three-year period following the grant date. Under both officer and key employee grants, applicable service requirements must be met in order for the Restricted Stock Units to vest.

Performance Stock Units for both officers and key employees vest if performance goals related to overall customer satisfaction, electric service power quality and reliability, generating plant availability, and net income (compared to budget) 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 whether and to what extent the performance goals have been met. In accordance with the 2006 Stock Incentive 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.

Restricted Stock Unit activity for 2006 is summarized in the following table:

	Non-employee Directors				
	Units				Weighte Averag Fair Value
Restricted Stock Units:					
Stock units outstanding - January 1, 2006	-			$	
Stock units granted:					
July 13, 2006 grant	9,608				24.9
November 16, 2006 grant	801				28.0
Stock units forfeited	(901	)			24.4
Stock units vested	(4,767	)			25.8
Stock units outstanding - December 31, 2006	4,741				24.7

Performance Stock Unit activity for 2006 is summarized in the following table:

	Officers and Key Employees				
	Units				Weighted Average Fair Value
Performance Stock Units:					
Stock units outstanding - January 1, 2006	-			$	-
July 13, 2006 grant (*)	89,238				24.96
Stock units forfeited	-				
Stock units vested	-				

Stock units outstanding - December 31, 2006	89,238				24.96	

(*) Based upon target performance; excludes DER shares.

A total of 4,502,553 shares remain available for future grants. The plan had no material impact on cash flow for the year ended December 31, 2006.

Effective July 1, 2006, PGE adopted SFAS No. 123R, Share-Based Payment, which requires that the compensation cost related to share-based payment transactions be recognized in financial statements at fair value, based on the market price of the underlying common stock on the date of grant, and charged to expense over the vesting period based on the number of shares expected to vest. No compensation cost is recognized for unvested awards that are forfeited. The Company adopted SFAS No. 123R using the Modified Prospective Application method, which applies to new awards and to awards modified, repurchased, or cancelled as of the beginning of the period in which SFAS No. 123R is adopted. For the year ended December 31, 2006, PGE recorded $1 million of stock-based compensation expense (included in Administrative and other expense in the Consolidated Statements of Income), with a corresponding credit to common stock equity. No equity compensation costs were capitalized. Based upon the attainment of performance goals that would allow the vesting of 100% of awarded Performance Stock Units, and utilizing an estimated forfeiture rate of 3%, unrecognized compensation expense related to unvested Stock Units was $3.7 million at December 31, 2006, of which $1.6 million, $1.4 million, and $0.7 million is expected to be expensed in 2007, 2008, and 2009, respectively.

Note 6 - Earnings Per Share

The following table presents the computation of basic and diluted earnings per common share for the years indicated:

Numerator:		

Net Income (in millions)		$
Denominator (in thousands):		
Weighted-average common shares outstanding-basic		
Effect of dilutive securities:		
Restricted Stock*		
Weighted-average common shares outstanding-diluted		
Earnings per share - basic		$
Earnings per share - diluted		$

* Restricted Stock Units and related Dividend Equivalent Rights granted under the Portland General Electric Company 2006 Stock Incentive Plan are discussed in Note 5, Stock-Based Compensation.

Note 7 - Credit Facility and Debt

At December 31, 2006, PGE had a $400 million five-year unsecured revolving credit facility with a group of commercial banks. The facility, which expires in 2011, is available for general corporate purposes, with the maximum amount available to PGE for borrowings and/or the issuance of standby letters of credit. The 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 facility. The facility provides that all outstanding loans mature on the termination date of the facility, provided that annually such date may be extended for an additional year for those lenders who agree to an extension. The 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 facility, to 65% of total capitalization. At December 31, 2006, PGE was in compliance with this covenant.

Pursuant to PGE's application, the Federal Energy Regulatory Commission (FERC) issued an order on February 3, 2006 which authorized the Company to issue short-term debt, including commercial paper, in an amount not to exceed $400 million outstanding at any one time, over the two-year period February 8, 2006 through February 7, 2008. 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. The commercial paper program is supported by the Company's $400 million five-year unsecured revolving credit facility. The amount available under the commercial paper program is limited to the unused line of credit under the revolving credit facility. PGE had $81 million in short-term commercial paper debt outstanding at December 31, 2006 and had utilized approximately $6 million in letters of credit. The Company had no short-term borrowings in 2005.

PGE management believes that its existing line of credit and cash from operations provide the Company with sufficient liquidity to meet its day-to-day cash requirements. 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. Due to the short-term nature of the commercial paper, the fair value of such instruments approximates their book value.

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

As of year-end:	
Aggregate short-term debt outstanding	
Commercial paper	

Weighted average interest rate*

Commercial paper

$

Unused committed line of credit

For the year ended:

Average daily amounts of short-term debt outstanding

$

Commercial paper

Weighted daily average interest rate*

Commercial paper

$

Maximum amount outstanding during the year

* Interest rates exclude the effect of commitment fees, faci

The Indenture securing PGE's First Mortgage Bonds constitutes a direct first mortgage lien on substantially all utility property and franchises, other than expressly excepted property.

Schedule of Long-Term Debt at December 31:		2006			
		(In Millio			
First Mortgage Bonds					
Maturing 2007 - (7.15%)	$	50			$
Maturing 2010 - (8 1/8%)		-			
Maturing 2012 - (5.6675%)		100			
Maturing 2013 - (5.279% - 5.625%)		100			
Maturing 2021 - 2033 (6.75% - 9.31%)		120			
		100			

Maturing 2031 - (6.26%)					
Maturing 2036 - (6.31%)		175			
		645			
Pollution Control Bonds					
Port of Morrow, Oregon, variable rate, due 2033					
(5.20% fixed rate to 2009)		23			
City of Forsyth, Montana, variable rate, due 2033					
(5.20% - 5.45% fixed rate to 2009)		119			
Port of St. Helens, Oregon, 4.80% due 2010		37			
Port of St. Helens, Oregon, due 2014					
(5.25% - 7.13% fixed rate)		15			
		194			
Other					
6.91% Conservation Bonds maturing monthly to 2006		-			
7.875% Notes due March 15, 2010		149			
7.75% Series Cumulative Preferred Stock (b)		16			
Unamortized debt discount		(1	)		
		164			
		1,003			
Long-term debt due within one year (a)		(66	)		
Total long-term debt	$	937			$

(a) Consists of 7.15% First Mortgage Bonds due June 15, 2007 and the 7.75% Series Cumulative Preferred Stock.

(b) The 7.75% Series Cumulative Preferred Stock (no par value), which is mandatorily redeemable, is classified as long-term debt in accordance with SFAS No. 150. The preferred stock series is redeemable by operation of a sinking fund that requires the annual redemption of 15,000 shares at $100 per share beginning in 2002, with all remaining shares to be redeemed by sinking fund in 2007. At its option, PGE may redeem, through the sinking fund, an additional 15,000 shares each year. Open market share purchases can be applied towards the annual redemption requirement. In 2006, PGE redeemed 30,000 shares, consisting of 15,000 shares for the annual sinking fund requirement and 15,000 additional shares acquired at its option. At December 31, 2006, there were 159,727 shares outstanding.

The following principal amounts (in millions) of long-term debt become due through regular maturities for the years indicated:

	2007	2008	2009	2010	2011	Th
Debt						
Maturities	$66	$ -	$ -	$186	$ -	

On December 19, 2006, PGE and certain institutional buyers in the private placement market entered into an agreement under which PGE will sell $170 million of PGE's First Mortgage Bonds to the buyers. The bonds are to be issued at the direction of PGE at any time up to, but not later than, June 1, 2007. The bonds will bear interest from the original issue date at an annual rate of 5.80%, and will mature on June 1, 2039. The bonds will be issued pursuant to a Bond Purchase Agreement between PGE and the buyers and under PGE's Indenture of Mortgage and Deed of Trust, dated July 1, 1945, as supplemented, including the Fifty-seventh Supplemental Indenture dated December 1, 2006, between PGE and HSBC Bank USA, National Association (as successor to The Marine Midland Trust Company of New York) in its capacity as trustee. PGE intends to use the proceeds from the sale of the bonds for general corporate purposes, which may include capital expenditures and/or the repayment of existing debt.

Note 8 - Other Financial Instruments

The following methods and assumptions were used to estimate the fair value of each class of financial instrument for which it is practical to estimate.

Cash and cash equivalents, Customer and other receivables, and Accounts payable

- These items are reported at their carrying values as these are a reasonable estimate of their fair value.

Other investments

- The carrying amounts of other investments are based on the underlying trust investments in marketable securities, consisting of money market, bond, and equity mutual funds, are classified as trading and approximate fair value. These include the Nuclear decommissioning trust, Non-qualified benefit plan trust, and other miscellaneous financial instruments.

Long-term debt

- 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. The estimated fair values of debt instruments are as follows (in millions):

	2006		200
	Carrying Amount	Fair Value	Carrying Amount
Long-term debt including current maturities	$1,003	$1,046	$890

Note 9 - Commitments and Guarantees

Natural Gas Agreements

PGE has entered into agreements for the purchase and transportation of natural gas from domestic and Canadian sources for its natural gas-fired generating facilities. The Company has also entered into a ten-year natural gas storage agreement, effective May 1, 2007, for the purpose of fueling the Company's Port Westward and Beaver generating plants located adjacent to the storage facility. As of December 31, 2006, these agreements require net payments of approximately $34 million in 2007, $21 million in both 2008 and 2009, $19 million in 2010, $16 million in 2011, and $70 million over the remaining years of the contracts, which expire at varying dates from 2007 to 2018.

Purchase Commitments

Certain commitments have been made for capital and other purchases for 2007 and beyond. Such commitments total $263 million as of December 31, 2006, reflecting future payment requirements of $221 million in 2007, $34 million in 2008, $6 million in 2009, and $2 million in 2010. Such commitments include those related to construction of Port Westward and the Biglow Canyon Wind Farm, Trojan and Bull Run decommissioning activities, hydro license agreements, information systems, upgrades to production and distribution facilities, and system maintenance work. Termination of these agreements could result in cancellation charges.

Coal and Transportation Agreements

PGE has coal and related rail transportation agreements with take-or-pay provisions of approximately $13 million in 2007, $14 million in 2008, and $4 million annually from 2009 through 2013.

Purchased Power

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 hydro projects whether or not they are operable. Selected information regarding these projects is summarized as follows (dollars in millions):

	Rocky Reach		Priest Rapids		W
Revenue bonds outstanding at					
December 31, 2006	$ 380		$ 265		
PGE's current share of:					
Output	12.0	%	7.5	%	
Net capability (megawatts)	154		65		
PGE's annual cost, including debt service:					
2006	$ 9		$ 3		
2005	8		4		
2004	8		4		
Contract expiration date	2011		*		

* Expires at the end of the license term to be determined by the FERC.

PGE's share of debt service costs, excluding interest, is approximately $8 million annually in 2007 and 2008, $9 million in 2009, and $7 million annually in 2010 and 2011. Total minimum payments through the remainder of the contracts are estimated at $55 million.

PGE has executed new agreements with Grant County Public Utility District (Grant), operator of the Priest Rapids and Wanapum projects, for periods corresponding to Grant's new license term, to be determined by the FERC. The new Priest Rapids agreement became effective November 1, 2005. The new Wanapum agreement is effective upon expiration of the current contract and the issuance of a new license to Grant. Under the agreements, Grant will annually determine the output required for its purposes, with PGE required to purchase approximately 25% of the output beyond Grant's needs over the term of the new license, for which PGE will pay a proportional share of the project's debt service and operating costs.

In November 2004, Douglas County PUD (Douglas), owner of the Wells Hydroelectric Project (Project), entered into a settlement with the Colville Confederated Tribes (Colville Tribe) that resolved claims for charges for the use of Colville tribal lands. The settlement, which was approved by the FERC in February 2005, impacted the quantity and price of PGE's share of the output of the Project. The settlement required that Douglas pay a $13.5 million lump sum, convey certain real property, and allocate (at cost) 4.5% of Project's output to the Colville Tribe; such allocation increases to 5.5% for all years after 2018. To fund the $13.5 million payment, PGE and other purchasers of the Project's output entered into a Settlement Endorsement Agreement (Agreement) providing for the sale by Douglas of revenue bonds. The Agreement requires that each purchaser of the Project's output pay their respective share of debt service on the revenue bonds, with PGE's annual share calculated at approximately $350,000. In addition to its share of debt service payments, PGE's share of the Project's output was reduced from 20.3% to 19.4% beginning in April 2005. The effects of both the debt service requirement and the reduction in output were included in projected power costs in PGE's RVM filings approved by the OPUC.

As of December 31, 2006, PGE has power purchase contracts with other counterparties, requiring payments of approximately $665 million in 2007, $214 million in 2008, $77 million in

2009, $78 million in 2010, $77 million in 2011, and $625 million over the remaining years of the contracts, which expire at varying dates from 2012 to 2035. PGE also has power capacity contracts as of December 31, 2006 that require payments of approximately $23 million annually from 2007 through 2011 and are expected to average approximately $19 million from 2012 through 2016. As of December 31, 2006, PGE has power sale contracts with other counterparties of approximately $343 million in 2007, $50 million in 2008, $5 million annually in 2009, 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. There was no outstanding exchange balance under this contract at December 31, 2006. The other exchange contract is with a winter-peaking Northwest utility to help meet the Company's summer-peaking power requirements. At December 31, 2006, PGE owed 8,863 MWhs of electricity, all of which are expected to be delivered by the end of February 2007.

Leases

PGE has an operating lease for its headquarters complex located in Portland, Oregon. The Company's Beaver Generating Plant and Port Westward Generating Plant are located on leased property near Clatskanie, Oregon; the lease for this property was extended in 2006 to the year 2096.

Future minimum payments under non-cancelable leases are as follows (in millions):

Year Ending December 31	Operating Leases (Net of Sublease Rentals)
2007	$ 8
2008	8
2009	7

2010	7
2011	8
Remainder	227
Total	$265

Included in the above table is approximately $121 million for PGE's headquarters complex, reflecting the base lease period through 2018 and renewal period options through 2043. Also included is $98 million for the generating plant land lease described above.

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 lessor 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 2007 is approximately $186 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 finance 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. The Company has not recorded any liability on the Consolidated Balance Sheets with respect to these indemnifications. Based on PGE's historical experience and the evaluation of the specific indemnities, management believes the likelihood that PGE would be required to perform or otherwise incur any significant losses is remote.

Note 10 - Price Risk Management

PGE utilizes derivative instruments, including electricity forward, swap, and option contracts and natural gas forward, swap, option, and futures contracts in its retail (non-trading) electric utility activities to manage its exposure to commodity price risk and to minimize net power costs for service to its retail customers. Under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (as amended), derivative instruments are recorded on the Consolidated Balance Sheets as an asset or liability measured at estimated fair value, with changes in fair value recognized currently in earnings, unless specific hedge accounting criteria are met.

Changes in the fair value of retail (non-trading) derivative instruments prior to settlement that do not qualify for either the normal purchase and normal sale 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 Operating Revenues, with purchases, natural gas swaps and futures recorded in Purchased Power and Fuel expense. PGE records the non-physical settlement of non-trading electricity derivative activities on a net basis in Purchased Power and Fuel expense, in accordance with EITF No. 03-11, Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, and "Not Held for Trading Purposes."

Special accounting for qualifying hedges allows gains and losses on a derivative instrument to be recorded in OCI until they can offset the related results on the hedged item in the Income Statement. The effects of changes in fair value of derivative instruments entered into to hedge the Company's future non-trading retail resource requirements are subject to regulation; accordingly, the unrealized gains and losses are deferred pursuant to SFAS No. 71.

PGE discontinued its electricity and natural gas trading (non-retail) activities in early 2005. Unrealized and realized gains and losses on the settlement of all derivative instruments related to such activities were reported on a net basis, as required by EITF 02-3, Accounting for Contracts Involved in Energy Trading and Risk Management Activities.

Non-Trading Activities

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. Most of PGE's non-trading wholesale sales have been to utilities and power marketers and have been predominantly short-term. In this process, PGE may net purchases and sales with the same counterparty rather than simultaneously receiving and delivering physical power. These net transactions are also referred to as "book outs." Only the net amount of those purchases or sales required to fulfill retail and wholesale obligations are physically settled.

Prior to December 2006, PGE recorded a regulatory asset or regulatory liability under

SFAS No. 71 to offset unrealized gains and losses on certain non-trading contracts recorded prior to settlement to the extent that such contracts are included in the Company's RVM. Upon settlement, the regulatory asset or regulatory liability is reversed. In its January 2007 general rate order, the OPUC approved a new PCAM by which PGE can adjust future rates to reflect the difference between each year's forecasted and actual net variable power costs on a settlement basis. As a result, a regulatory asset or regulatory liability is recorded to offset changes in fair value of derivative instruments not included in the RVM. Effective January 17, 2007, a new Annual Power Cost Update Tariff replaced the RVM.

The following table indicates unrealized gains and losses recorded in earnings for the years indicated (in millions):

			2
Non-Trading Activities			
Net unrealized gains (losses)		$	
SFAS No. 71 regulatory (liability) asset			
Net unrealized gains (losses)		$	

The following table indicates derivative activities from cash flow hedges recorded in OCI for the years indicated (in millions):

			2
Derivative Activities Recorded in OCI			
Unrealized holding net gains (losses) arising during the period		$	
Reclassification adjustment for contract settlements included in net income			

Reclassification adjustment in net income due to discontinuance of cash flow hedges (*)			
Reclassification of unrealized (gains) losses to SFAS No. 71 regulatory (liability) asset			
Total - Unrealized gains (losses) on derivatives classified as cash flow hedges		$	

(*) Due to the probability that the original forecasted transactions will not occur.

Hedge ineffectiveness from cash flow hedges was not material in 2006, 2005, and 2004. As of December 31, 2006, the maximum length of time over which PGE is hedging its exposure to such transactions is approximately 57 months. The Company estimates that of the $5 million of net unrealized gains in OCI at December 31, 2006, $1 million will be reclassified into earnings within the next twelve months (fully offset by SFAS No. 71 regulatory liabilities) and the remaining $4 million will be reclassified over the remaining 45 months (fully offset by SFAS No. 71 regulatory liabilities).

Trading Activities

Prior to 2005, PGE utilized forward, swap, option, and futures contracts to participate in electricity and natural gas markets for non-retail purposes. In early 2005, PGE discontinued its trading activities for non-retail purposes, with existing trading transactions settled by December 31, 2005. Such activities were not reflected in PGE's retail prices.

As indicated above, all unrealized and realized gains and losses associated with "energy trading activities" are reported on a net basis for all periods presented. The following tables indicate unrealized and realized gains and losses on electricity and natural gas trading activities and transaction volumes for electricity trading contracts that settled in the years indicated:

		2006
Trading Activities (In Millions)		
Unrealized Gain (Loss)	$	-
Realized Gain		-
Net Gain in Operating Revenues	$	-
Electricity Trading - MWhs (thousands)		
Sales		-
Purchases		-

Note 11 - Jointly Owned Plant

At December 31, 2006, PGE had the following investments in jointly owned generating plants (dollars in millions):

			PGE Interest	
Facility	Location	Fuel	Percent	MW Capac
Boardman	Boardman, OR	Coal	65.00	3
Colstrip 3 and 4	Colstrip, MT	Coal	20.00	2
Pelton/Round Butte	Madras, OR	Hydro	66.67	2

(*) Excludes "Asset Retirement Obligations" and "Accumulated Asset Retirement Removal Costs."

Above amounts represent PGE's share of each jointly owned plant, with the Company's share of both direct expenses and utility plant costs included in its financial statements. Each joint owner of the plants has provided its own financing. PGE operates Boardman and

Pelton/Round Butte; PPL Montana, LLC operates Colstrip 3 and 4.

Note 12 - Asset Retirement Obligations

Under SFAS No. 143, Accounting for Asset Retirement Obligations, and FASB Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations (FIN 47), PGE recognizes as Asset Retirement Obligations (AROs) those legal obligations associated with the disposal of long-lived assets that result from the acquisition, construction, development or normal operation of such assets. Concurrent with the recognition of the liability, estimated costs of asset retirement obligations are capitalized and depreciated over the remaining life of the asset, with accretion of the ARO liability recorded as an operating expense. On the Statement of Income, amounts are included in Depreciation and Amortization expense for Utility plant and Other Income (Deductions) for Other property.

Regulation -

Pursuant to regulation, AROs of rate-regulated long-lived assets are included in depreciation expense and allowed in rates 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 No. 71. Substantially all significant AROs are included in rate regulation, and PGE expects any changes in estimated AROs to be incorporated in future rates.

Asset Retirement Obligations

- At December 31, 2006, PGE's asset retirement obligations include $108 million associated with the Trojan plant, representing the present value of future decommissioning expenditures. Site specific AROs, totaling $15 million, have also been recognized for rate-regulated utility plant, consisting of the Boardman and Colstrip Units 3 and 4 coal plants, the Coyote Springs, Beaver, and Port Westward gas turbine plants, and the Bull Run hydro project. A $2 million conditional asset retirement obligation, resulting from the adoption and application of FIN 47 in 2005, has been recognized for the disposal cost of assets subject to specific environmental regulation, including costs related to treated pole disposal, mercury vapor light disposal, asbestos remediation, polychlorinated biphenyl (PCB) disposal, underground storage tank removal, and other miscellaneous disposal costs. A total of $9 million in AROs for non-utility property has also been recognized. The following table indicates activity and balances for the Company's AROs included on the Consolidated Balance Sheets for the years indicated (in millions):

	For Year Ended December 31,		
	2006	2005	2004
Beginning Balance	$ 134	$ 120	$ 129
Activity			
AROs incurred	-	2	-
Expenditures	(6)	(4)	(17
Accretion	7	6	6
Revisions	(1)	10	2
Ending Balance	$ 134	$ 134	$ 120

Unrecognized Asset Retirement Obligations

PGE has certain tangible long-lived assets for which AROs are not currently measurable, the recording of which will be required when circumstances change. Those assets that may require removal when the plant is no longer in service include the Oak Grove hydro project and transmission and distribution plant located on public right-of-ways and on certain easements. Management believes that these assets will be used in utility operations for the foreseeable future.

Note 13 - Trojan Nuclear Plant

Plant Shutdown and Fuel Storage

- In 1993, PGE ceased commercial operation of Trojan, in which the Company has a 67.5% ownership share. In May 2005, following completion of radiological decommissioning and approval of the Nuclear Regulatory Commission (NRC), the plant's operating license was terminated. Spent nuclear fuel is stored in the ISFSI, an NRC-approved interim dry storage facility that houses the fuel at the plant site until permanent off-site storage is available.

Decommissioning - The Trojan decommissioning plan includes an estimate of PGE's cost to decommission the plant. The original cost estimate was based upon a site-specific engineering study. A Decommissioning Cost Forecast is maintained and periodically updated by PGE. The cost forecast has been revised to reflect actual costs and changes in the timing of decommissioning activities, due primarily to a delay in the completion of a permanent spent fuel storage facility. At December 31, 2006, the asset retirement obligation, measured at estimated fair value in accordance with SFAS No. 143, is $108 million. (See Note 12, Asset Retirement Obligations, for further information).		
		ASSET
		Balance, 12/
		2006 Expend
		2006 Accret
		Balance, 12/
		Total expend 12/31/06

Remaining decommissioning activities consist of demolition of the existing structures, operation of the ISFSI to the year 2030, and decommissioning of the ISFSI. Final site restoration activities are anticipated to begin in 2031 following shipment of spent fuel to a United States Department of Energy (USDOE) facility (see "Nuclear Fuel Disposal and Cleanup of Federal Plants" below).

	DECOMMISSIONING TRUST ACTIVITY					
	(In Millions)					

				2006	
Beginning Balance		$	31	$	
Activity					
	Contributions		14		
	Earnings		1		
	Disbursements		(4)		
Ending Balance		$	42	$	

In addition, the OPUC, in its January 2007 order in PGE's
of approximately $20 million from the trust fund, repres
activities.

Decommissioning trust funds are invested in a diversifi
balances are valued at market. Earnings on the trust fund a
from customers. PGE expects any future changes in estin
future revenues collected from customers.

Nuclear Fuel Disposal and Cleanup of Federal Plants

- PGE has contracted with the USDOE for permanent disposal of spent nuclear fuel in federal facilities and paid for such services, based on Trojan's generation, during the period of plant operation. The availability of an off-site repository for the permanent storage of radioactive waste would allow PGE to remove spent nuclear fuel from the ISFSI and allow final decommissioning and release of the ISFSI site for unrestricted use. Significant delays have occurred in the USDOE acceptance schedule for spent fuel from domestic utilities, with no federal repository expected to be available until after 2010.

In 2002, the USDOE formally recommended Yucca Mountain, Nevada as the nation's first long-term geologic (underground) repository for high-level radioactive waste produced in the United States. The proposed location is based on the conclusions of scientific studies of the site, conducted over 20 years, which support a finding of suitability, as mandated by the Nuclear Waste Policy Act and various regulations of the NRC, USDOE, and the U.S. Environmental Protection Agency (EPA). The House and Senate approved the site and in 2002, President Bush signed the Yucca Mountain resolution into law. Lawsuits have been filed objecting to the recommendation of Yucca Mountain as a nuclear waste repository. Based upon updated information received from the USDOE regarding the acceptance of spent nuclear fuel from Trojan, PGE has extended its projection for the final shipment of spent fuel from 2023 to 2030. Although it has not yet submitted the required application for an operating license for the repository, the USDOE in July 2006 announced plans to submit a license application to the NRC by June 30, 2008. Further delays may make it difficult for PGE to move its spent nuclear fuel, currently contained in the ISFSI, to permanent underground storage by 2030.

In 2004, the co-owners of Trojan (PGE, Eugene Water & Electric Board, and PacifiCorp) filed a complaint against the USDOE in the U.S. Court of Federal Claims for failure to accept spent nuclear fuel by January 31, 1998, as required by the Standard Form Contract. The plaintiffs paid for permanent disposal services during the period of plant operation (in the total amount of $109 million) and have met all other conditions precedent. Damages sought are in excess of $200 million.

The Energy Policy Act of 1992 provided for the creation of a Decontamination and Decommissioning Fund to finance the cleanup of USDOE gas diffusion plants, with funding provided by both domestic nuclear utilities and the federal government. Contributions are based upon each utility's share of total enrichment services purchased by all domestic utilities prior to enactment of the legislation. PGE's $17 million share of the total funding requirement, based on Trojan's 1.1% usage of total industry enrichment services, was paid in annual installments from 1993 through 2006.

Security Requirements -

In response to the terrorist attacks of September 11, 2001, the NRC issued interim compensatory security measures for a generalized high-level threat environment at closed nuclear reactors that are in the decommissioning process and at ISFSIs. The new requirements are expected to remain in effect until the NRC determines that the level of threat has diminished, or that other security changes are needed. The NRC issued additional security orders to all operating reactors in 2003 that require operating plants to update their defensive strategies to counter a highly organized attack. It is possible that corresponding similar orders (limited in scope) will eventually be issued to the Trojan ISFSI. Until NRC requirements associated with any new orders are determined, any implementation costs (including their impact on the Trojan decommissioning cost estimate and related funding requirements) are not determinable. However, as any new security requirements are evaluated, any additional costs will be determined and decommissioning cost estimates revised as necessary.

Nuclear Insurance -

The Price-Anderson Amendment of 1988 limits public liability claims that could arise from a nuclear incident and also provides for loss sharing among all owners of nuclear reactor licenses. Because Trojan has been permanently de-fueled, PGE has been exempted by the NRC from participation in the secondary financial protection pool covering losses in excess of $300 million at other nuclear plants. The NRC has also reduced the required primary nuclear insurance coverage for Trojan to $100 million and has allowed PGE to self-insure for on-site decontamination related to spent nuclear fuel stored in the ISFSI. PGE continues to insure non-contamination property, in the amount of $18.5 million, under the Company's "All Risk" property insurance on the Trojan plant.

Trojan ISFSI Pollution Control Tax Credits -

PGE received final certification from the OEQC related to $21.1 million in Oregon pollution control tax credits that were generated from PGE's investment in the ISFSI. The OEQC rules require that the tax credits be spread over a ten-year period, beginning in 2004. Accordingly, PGE records a regulatory liability to defer the utilization of these tax credits for future refund to customers.

Note 14 - Legal and Environmental Matters

Legal Matters

Trojan Investment Recovery

- In 1993, following the closure of the Trojan Nuclear Plant as part of its 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.

Numerous challenges, appeals and reviews were subsequently filed in the Marion County 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 URP each requested the Oregon Supreme Court to 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 has been remanded to the OPUC (1998 Remand).

In 2000, while the petitions for review of the 1998 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. 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. The largest of such amounts consisted of before-tax credits of approximately $79 million in customer benefits related to the previous settlement of power contracts with two other utilities and the approximately $80 million remaining credit due customers under terms of the 1997 merger of the Company's parent corporation at the time (Portland General Corporation) with Enron. The settlement also allowed PGE recovery of approximately $47 million in income tax benefits related to the Trojan investment which had been flowed through to customers in prior years; such amount was substantially recovered from PGE customers by the end of 2006. After offsetting the investment in Trojan with these credits and prior tax benefits, the remaining Trojan regulatory asset balance of approximately $5 million (after tax) was expensed. As a result of the settlement, PGE's investment in Trojan is no longer included in rates charged to customers, either through a return of or a return on that investment. Authorized collection of Trojan decommissioning costs is unaffected by the settlement agreements or the OPUC orders.

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 URP's challenges, and approving the accounting and ratemaking elements of the 2000 settlement. URP appealed the 2002 Order to the Marion County Circuit Court. On November 7, 2003, the Marion County Circuit Court issued an opinion remanding the case to the OPUC for action to reduce rates or order refunds (2003 Remand). The opinion does not specify the amount or timeframe of any reductions or refunds. PGE and the OPUC have appealed the 2003 Remand to the Oregon Court of Appeals.

The OPUC combined the 1998 Remand and the 2003 Remand into one proceeding and is considering the matter in phases. The first phase addresses what rates would have been if the OPUC had interpreted the law to prohibit a return on the Trojan investment. The subsequent phases will address reconciling the results of the first phase with actual rates, and adjusting rates to the extent necessary. On November 15, 2006, PGE filed a motion with the OPUC to Consolidate Phases and Re-Open the Record. A ruling on the motion is pending.

On February 16, 2007, the Oregon Court of Appeals declined to reverse or abate the 2003 Remand and ordered the parties to file revised briefs with the Court of Appeals.

In a separate legal proceeding, two class action suits were filed in Marion County 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 for the Current Class and $70 million for the Former Class, as a result of the inclusion of a return on investment of Trojan in the rates PGE charges 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 responds 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 rate reductions or refunds, for any amount of return on the Trojan investment PGE collected in rates for the period from April 1995 through October 2000. The Supreme Court further stated that if the OPUC determines that it can provide a remedy to PGE's customers, then the class action proceedings may become moot in whole or in part, but if the OPUC determines that it cannot provide a remedy, and that decision becomes final, the court system may have a role to play. The Supreme Court also ruled that the plaintiffs retain the right to return to the Marion County Circuit Court for disposition of whatever issues remain unresolved from the remanded OPUC proceedings. 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 February 14, 2005, PGE received a Notice of Potential Class Action Lawsuit for Damages and Demand to Rectify Damages from counsel representing Frank Gearhart, David Kafoury and Kafoury Brothers, LLC (Potential Plaintiffs), stating that Potential Plaintiffs intend to bring a class action lawsuit against the Company. Potential Plaintiffs allege that for the period from October 1, 2000 to the present, PGE's electricity rates have included unlawful charges for a return on investment in Trojan in an amount in excess of $100 million. Under Oregon law, there is no requirement as to the time the lawsuit must be filed following the 30-day notice period. No action has been filed to date.

Management cannot predict the ultimate outcome of the above matters. However, it believes these matters will not have a material adverse impact on the financial condition of the Company, but may have a material impact on the results of operations and cash flows for a future reporting period. No reserves have been established by PGE for any amounts related to this issue.

Multnomah County Business Income Taxes

- In January 2005, David Kafoury and Kafoury Brothers, LLC filed a class action lawsuit in Multnomah County Circuit Court against PGE on behalf of all PGE customers who were billed on their electric bills and paid amounts for Multnomah County Business Income Taxes (MCBIT) after 1996 that the plaintiffs alleged were never paid to Multnomah County. The plaintiffs sought judgment against PGE for restitution of MCBIT in excess of $6 million, plus interest, recoverable costs, punitive damages, and attorney fees.

On July 28, 2006, the Multnomah County Circuit Court approved a settlement providing for PGE refunds and payments totaling $10 million, inclusive of interest and plaintiffs' attorney fees, costs, and expenses as approved by the Court's final order. The settlement includes no admission of liability or wrongdoing by the Company. PGE established a reserve of $10 million in 2005 related to the settlement. Refunds to customers were completed in the fourth quarter of 2006.

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, in which PGE has a 20% ownership interest. In 2002 and 2003, WECO received two orders from the Office of Minerals Revenue Management of the U.S. Department of the Interior which asserted underpayment of royalties and taxes by WECO related to transportation of coal from the mine to Colstrip during the period October 1991 through December 2001. WECO subsequently appealed the two orders to the Minerals Management Service (MMS) of the U.S. Department of the Interior. On March 28, 2005, the appeal by WECO was substantially denied. On April 28, 2005, WECO appealed the decision of the MMS to the Interior Board of Land Appeals of the U.S. Department of the Interior. In late September 2006, WECO received an additional order from the Office of Minerals Revenue Management to report and pay additional royalties for the period January 2002 through December 2004.

In May 2005, WECO received a "Preliminary Assessment Notice" from the Montana Department of Revenue, asserting claims similar to those of the Office of Minerals Revenue Management.

WECO has indicated to the owners of Colstrip Units 3 and 4 that, if WECO is unsuccessful in the above appeal process, it will seek reimbursement of any royalty payments by passing these costs on to the owners. *The owners of Colstrip Units 3 & 4 advised WECO that their position would be that these claims are not allowable costs under either the Coal Supply Agreement or the Transportation Agreement.*

Management cannot predict the ultimate outcome of the above matters or estimate any potential loss. Based on information currently known to the Company's management, the Company does not expect that this issue will have a material adverse effect on its financial condition, results of operations or cash flows. If WECO is able to pass any of these costs on to the owners, the Company would most likely seek recovery through the ratemaking process.

City of Portland Challenge of Stock Issuance -

On February 10, 2006, the City of Portland appealed the OPUC order approving distribution of the new PGE common stock in both the Marion County Circuit Court and the Oregon Court of Appeals. On July 19, 2006, the Court of Appeals granted the OPUC motion to dismiss the action before that Court. On October 20, 2006, the City of Portland filed a Notice and Order of Voluntary Dismissal with the Marion County Circuit Court. On November 2, 2006, the Marion County Circuit Court dismissed the case.

Environmental Matters

Harborton -

A 1997 investigation by the EPA of a 5.5 mile segment of the Willamette River known as the Portland Harbor revealed significant contamination of sediments within the harbor. The EPA subsequently included the Portland Harbor on the federal National Priority List pursuant to the federal Comprehensive Environmental Response, Compensation, and Liability Act (Superfund). In December 2000, PGE received a "Notice of Potential Liability" regarding its Harborton Substation facility and was listed, along with sixty-eight other companies, on a list of Potentially Responsible Parties (PRPs) with respect to the Portland Harbor Superfund Site.

In February 2002, PGE provided a report on its remedial investigation of the Harborton site to the DEQ. The report concluded that there is no likely present or past source or pathway for release of hazardous substances to surface water or sediments in the Portland Harbor Superfund Site at or from the site and that the site does not present a high priority threat to present and future public health, safety, welfare, or the environment. The DEQ submitted the report to the EPA and, in a May 18, 2004 letter, the EPA notified the DEQ that based on the summary information from the DEQ and the stage of the process, the EPA as of that time, agreed the Harborton site does not appear to be a current source of contamination to the river.

In December 6, 2005 letter, the DEQ notified PGE that the site is not likely a current source of contamination to the river and that the site is a low priority for further action. Management believes that the Company's contribution to the sediment contamination, if any, from the Harborton Substation site would qualify it as a de minimis PRP.

Sufficient information is currently not available to determine either the total cost of investigation and remediation of the Portland Harbor or the liability of PRPs, including PGE. Management cannot predict the ultimate outcome of this matter or estimate any potential loss. However, it believes this matter will not have a material adverse impact on the Company's financial statements.

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 is also 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 that impacted an approximate two acre area. Elevated levels of contaminants, including metals, pesticides, and PCBs, have been detected at the site. On September 29, 2003, Harbor Oil was included on the federal National Priority List as a federal Superfund site.

PGE received a Special Notice Letter for Remedial Investigation/Feasibility Study 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 a Remedial Investigation and Feasibility Study of the Harbor Oil site. PGE, along with other PRPs, is negotiating an Administrative Order of Consent with the EPA to conduct a Remedial Investigation/Feasibility Study.

Sufficient information is currently not available to determine either 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. However, it believes this matter will not have a material adverse impact on the Company's financial statements.

Note 15 - Receivables and Refunds on Wholesale

Market Transactions

Receivables - California Wholesale Market

As of December 31, 2006, PGE has net accounts receivable balances totaling approximately $63 million from the California Independent System Operator (ISO) and the California Power Exchange (PX) for wholesale electricity sales made from November 2000 through February 2001. The Company estimates that the majority of this amount was for sales by the ISO and PX to Southern California Edison Company and Pacific Gas & Electric Company.

In March 2001, the PX filed for bankruptcy and in April 2001, Pacific Gas & Electric Company filed a voluntary petition for relief under the provisions of Chapter 11 of the federal Bankruptcy Code. PGE filed a proof of claim in each of the proceedings for all past due amounts. Although both entities have emerged from their bankruptcy proceedings as reorganized debtors, not all claims filed in the proceedings, including those filed by PGE, have been resolved. PGE is continuing to pursue collection of these claims.

Management continues to assess PGE's exposure relative to these receivables. Based upon FERC orders regarding the methodology to be used to calculate refunds related to California wholesale sales (see "Refunds on Wholesale Transactions" below) and the FERC's indication that potential refunds can be offset with accounts receivable related to such sales, PGE has established reserves totaling $40 million related to this receivable amount. The Company is examining numerous options, including legal, regulatory, and other means, to pursue collection of any amounts ultimately not received through the bankruptcy process.

Refunds on Wholesale Transactions

California

On July 25, 2001, the FERC issued an order in the California refund case (Docket No. EL00-95) establishing the scope of and methodology for calculating refunds for wholesale sales transactions made between October 2, 2000 and June 20, 2001 in the spot markets (defined by the FERC as 24 hours or less) operated by the ISO and PX. The order established evidentiary hearings to develop a factual record to provide the basis for the refund calculation. Several additional orders clarifying and further defining the methodology were issued by the FERC and all have been appealed by numerous parties. A hearing was held in 2002 and, on March 26, 2003, the FERC issued an order ruling on various outstanding issues as to how refunds were to be determined. Under this order, PGE estimates its potential liability at between $40 million and $50 million, of which $40 million has been established as a reserve, as discussed above.

Numerous parties, including PGE, filed requests for rehearing of various aspects of the March 26, 2003 order, including the methodology for the pricing of natural gas within the refund formula. On October 16, 2003, the FERC issued an order reaffirming, in large part, the methodology adopted in its March 26, 2003 order. PGE does not agree with the FERC's methodology for determining potential refunds, and, on December 20, 2003 the Company appealed the FERC's October 16, 2003 order to the U.S. Ninth Circuit Court of Appeals; several other parties have also appealed the October 16, 2003 order. On May 12, 2004, the FERC issued an order that denied further requests for rehearing of the October 16, 2003 order. Although there continue to be miscellaneous orders issued in the underlying FERC proceeding, the Ninth Circuit has now begun to hear the numerous appeals. It bifurcated appeals of the existing cases into two phases. The first phase (Phase I) considered arguments regarding jurisdictional issues and the permissible scope of refund liability, both in terms of the time frame for which refunds were ordered and the types of transactions subject to refund. The second phase will consider the issues relating to the refund methodology itself. PGE expects that the Court will establish additional phases as the issues remaining before the FERC become final and are appealed.

As to the jurisdictional issues in Phase I, on September 6, 2005, the Court ruled that the FERC did not have jurisdiction to order municipal utilities and other governmental entities to make refunds for the sales they had made to the ISO and PX that are the subject of the refund proceeding. Requests for rehearing have been filed with regard to this decision.

On August 2, 2006, the Ninth Circuit issued its decision on the remainder of the issues in Phase I (Refund Scope Decision). It upheld the refund effective date of October 2, 2000, but remanded to the FERC the issue of whether it should order refunds for the summer 2000 period pursuant to its authority under Section 309 of the Federal Power Act (FPA) to remedy tariff violations. It also affirmed the FERC's orders on the scope of the refund proceeding, except with regard to the FERC's exclusion of ISO and PX contracts in excess of 24 hours and energy exchanges, and held that transactions in the ISO and PX markets with a duration in excess of 24 hours, as well as energy exchanges, should be included within the scope of the refund case. Although the August 2, 2006 Ninth Circuit decision did not mandate industry-wide refunds for the summer 2000 period, it is possible that, upon remand, the FERC could decide to order such additional refunds. Management cannot predict the outcome of any proceeding or how summer refunds, if they are ordered, might be calculated.

The Ninth Circuit has ordered an extension of the due date for the filing of requests for rehearing of its Refund Scope Decision until April 29, 2007, establishing a mediation process and urging the parties to use the time to assess possibilities of settlement.

Within the refund case, the FERC also issued a series of orders that permit generators serving California to recover certain costs of emission allowances and the costs of fuel incurred to generate power that were in excess of the gas cost component used to establish the refund liability. Under the methodology adopted by the FERC to allocate fuel costs, PGE could be required to pay additional amounts in those hours when it was a net buyer in California spot markets, thus increasing its net refund liability. PGE does not expect a material increase in the Company's potential refund exposure. Partly as a means of limiting its exposure to additional fuel costs and other potential refund liabilities, PGE has opted to become a participant in several settlements filed in the refund case since 2004.

In August 2005, PGE joined in a settlement agreement resolving issues relating to the allocation of the wind-up costs of the PX for both past and future periods. The settlement has been approved by the FERC. Although under the agreement PGE will bear certain additional costs associated with PX obligations to conduct and finalize refund calculations, PGE does not expect those costs to be material to its financial statements.

In several of its underlying refund orders, the FERC has indicated that if marketers, such as PGE, believe that the level of their refund liability has caused them to incur an overall revenue shortfall for their sales to the ISO and PX during the refund period, they will be permitted to file a cost study to prove that they should be permitted to recover additional revenues in excess of the mitigated prices in order to cover their costs. By order issued August 8, 2005, the FERC provided guidelines regarding the manner in which these studies should be conducted and the principles that should govern their preparation. On September 14, 2005, PGE filed a cost recovery study with the FERC. By order issued November 2, 2006, the FERC accepted, subject to PGE making certain additional revisions, a revised cost recovery study that had been filed by PGE in response to an earlier January 26, 2006 order. Pursuant to the November 2, 2006 order, PGE filed a final cost study with the ISO that now reflects an approximate $19.8 million cost offset to its refund obligation. Third parties have challenged PGE's cost recovery filings and made numerous requests that they be rejected in their entirety or that the cost offset be reduced to zero. PGE has filed responses to those challenges.

PGE believes that the FERC erred in certain findings in its orders regarding PGE's cost recovery and has filed requests for rehearing as to several issues in those orders. Due to the continuing uncertainty related to these matters, PGE has made no adjustment to the $40 million reserve previously established for the Company's potential liability, as described above.

The FERC has indicated that any refunds PGE may be required to pay related to California wholesale sales (plus interest from collection date) can be offset by accounts receivable (plus interest from due date) related to sales in California (see "Receivables - California Wholesale Market" above). In addition, any refunds paid or received by PGE applicable to spot market electricity transactions on and after January 1, 2001 in California may be eligible for inclusion in the calculation of net variable power costs under the Company's power cost adjustment mechanism in effect at that time. This could further mitigate the financial effect of any refunds made or received by the Company.

Challenge of the California Attorney General to Market-Based Rates

- On March 20, 2002, the California Attorney General filed a complaint with the FERC against various sellers in the wholesale power market, alleging that the FERC's authorization of market-based rates violated the FPA, and, even if market-based rates were valid under the FPA, that the quarterly transaction reports required to be filed by sellers, including PGE, did not contain the transaction-specific information mandated by the FPA and the FERC. The complaint argued that refunds for amounts charged between market-based rates and cost-based rates should be ordered. The FERC denied the challenge to market-based rates and refused to order refunds, but did require sellers, including PGE, to re-file their quarterly reports to include transaction-specific data. The California Attorney General appealed the FERC's decision to the Ninth Circuit. On September 8, 2004, the Court issued an opinion upholding the FERC's authority to approve market-based tariffs, but also holding that the FERC had the authority to order refunds, if quarterly filing of market-based sales transactions had not been properly made. The Court required the FERC, upon remand, to reconsider whether refunds should be ordered. On October 25, 2004, certain parties filed a petition for rehearing with the Court. On July 31, 2006, the Court summarily denied rehearing, and on December 28, 2006, PGE joined with other parties in filing a petition for certiorari of this decision with the U.S. Supreme Court. On February 5, 2007, the California Attorney General filed in opposition to the petition for certiorari, or, in the alternative if the petition is granted, a cross-petition for certiorari challenging the legality of market-based rate tariffs.

In the refund case and in related dockets, including the above challenge to market based rates, the California Attorney General and other California parties have argued that refunds should be ordered retroactively to at least May 1, 2000.

Management cannot predict the outcome of these proceedings or whether the FERC will order refunds retroactively to May 1, 2000, and if so, how such refunds would be calculated.

Anomalous Bidding Allegations

By order issued on June 25, 2003, the FERC instituted an investigation into allegations of anomalous bidding activities and practices ("economic withholding") on the part of numerous parties, including PGE. The FERC determined that bids above $250 per MW in the period from May 1, 2000 through October 2, 2000 may have violated tariff provisions of the ISO and the PX. The FERC required companies that bid in excess of $250 per MW to provide information on their bids to the FERC investigation staff. PGE responded to the FERC's inquiries and, on May 12, 2004, the FERC investigation staff issued to PGE a letter terminating the investigation as to the Company without further action. On March 10, 2005, certain California parties filed appeals with the Ninth Circuit, contesting the FERC's conduct of the investigation of the anomalous bidding allegations and the issuance of the dismissal letters.

Pacific Northwest

In the July 25, 2001 order, the FERC also 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 July 2003, numerous parties filed requests for rehearing of the June 2003 FERC order. In November 2003 and February 2004, the FERC issued orders that denied all pending requests for rehearing. Parties have appealed various aspects of these FERC orders. Briefing has been completed and oral argument was held on January 8, 2007. A decision in the case is pending.

Management cannot predict the ultimate outcome of the above matters related to wholesale transactions in California and the Pacific Northwest. However, it believes that the outcome will not have a material adverse impact on the financial condition of the Company, but may have a material impact on the results of operations and cash flows for future reporting periods.

Note 16 - Utility Rate Treatment of Income Taxes

In 2005, the Oregon legislature passed a law that adjusts the way that PGE and other Oregon investor-owned electric and gas utilities recover income tax expense from customers through revenues for utility services. The law, commonly referred to as SB 408, 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 investor-owned utilities or their consolidated group. The new law requires that utilities file a report with the OPUC each year regarding the amount of taxes paid by the utility or its consolidated group (with certain adjustments), as well as the amount of taxes authorized to be collected in rates, as defined by the statute. This report is to be 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 establish an "automatic adjustment clause" to adjust rates. The first adjustment under the automatic adjustment clause applies only to taxes paid to units of government and collected from customers on or after January 1, 2006.

On September 14, 2006, the OPUC issued a final order (Final Order) that adopted permanent rules

(Rules) to implement SB 408. In the Rules, the OPUC adopted the use of fixed reference points for margins and effective tax rates from a ratemaking proceeding. The OPUC also adopted a methodology to determine the amounts properly attributed to the utility from a consolidated tax payment using a formula to determine the ratio of the utility's payroll, property and sales to the consolidated group's amounts for the same items. This ratio is then multiplied by the amount of total taxes paid by the consolidated group to determine the utility's attributed portion. The OPUC also determined that interest should begin to accrue beginning January 1, 2006 using a mid-year convention for differences between income taxes collected and income taxes paid to governmental entities for tax year 2006.

In the Final Order, the OPUC addressed the so-called "double whammy" effect wherein the application of the Rules can result in unusual outcomes in certain situations. If a utility incurs higher expenses or receives lower revenues, resulting in lower taxes paid than the OPUC assumed it would incur in its last rate case, the automatic adjustment clause under SB 408 will require the utility to make a refund to customers and decrease the utility's earnings. Conversely, if a utility incurs lower expenses or receives higher revenues, resulting in higher taxes paid than the OPUC assumed it would incur in its last rate case, the automatic adjustment clause under SB 408 will surcharge customers and increase the utility's earnings. The OPUC stated in the Final Order that it will be responsive to concerns related to the consequences of the "double whammy" problem, and may address those concerns in other regulatory proceedings; however, it did not provide clear guidance on avenues of relief.

On December 30, 2005, PGE filed with the OPUC an application for deferred accounting to prevent either the financial enrichment or financial harm to the Company should the rules implementing SB 408 include the use of fixed reference points for margins and effective tax rates from a ratemaking proceeding. The Rules do use fixed reference points for margins and effective tax rates from a ratemaking proceeding. The deferred amount would reflect the tax effect of the difference between PGE's implied operating costs under a fixed margin assumption and the Company's actual operating costs. In an interim order in the rulemaking process, the OPUC indicated that it would review deferral applications related to SB 408 on a case by case basis, but would view such applications with skepticism.

Effective with the April 3, 2006 issuance of new PGE common stock, PGE is no longer a subsidiary of Enron and files its own consolidated tax returns and remits payments directly to taxing authorities. However, in April 2006, PGE paid $17 million to Enron for net current taxes payable for the first quarter of 2006 when PGE was still included in Enron's consolidated group for filing consolidated federal and state income tax returns. Under the Rules, PGE will likely be required to refund to customers the majority of this amount.

As a result of its assessment of the Rules, PGE has estimated its potential refunds to customers to be approximately $42 million (including $2 million of accrued interest) for 2006 and has recorded a (pre-tax) reserve of such amount for the year. In accordance with the statute, the Company will file a report with the OPUC by October 15, 2007 for the 2006 tax year regarding the amount of taxes paid by the Company as well as the amount of taxes authorized to be collected in rates, as defined by the statute. Any refunds to customers for the 2006 tax year would begin after June 1, 2008.

PGE will continue to evaluate its options for changing or modifying the legislation and Rules, and challenging any adjustment that follows for the 2006 tax year.

Complaint and Application for Deferral - Income Taxes

- On October 5, 2005, the Utility Reform Project and Ken Lewis (Complainants) filed a Complaint with the OPUC alleging that, since September 2, 2005 (the effective date of SB 408), PGE's rates are not just and reasonable and are in violation of SB 408 because they contain approximately $92.6 million in annual charges for state and federal income taxes that are not being paid to any government. The Complaint requests that the OPUC order the creation of a deferred account for all amounts charged to ratepayers 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.

Also on October 5, 2005, the Complainants filed an Application for Deferred Accounting with the OPUC, claiming that PGE is charging ratepayers $92.6 million annually for federal and state income taxes that are not being paid, and that such charges are not fair, just and reasonable. The Application for Deferred Accounting requests that the portion of PGE's revenue representing estimated PGE liabilities for federal and state income taxes, less any amounts of federal and state income taxes paid by PGE or on behalf of PGE, be deferred for later incorporation in rates. PGE opposes the deferral and has moved to dismiss the Complaint.

On July 10, 2006, the OPUC commenced proceedings on the Complaint and Deferral. Management cannot predict the ultimate outcome of this matter or estimate any potential loss.

Note 17 - Related Party Transactions

The tables below detail the Company's related party balances and transactions (in millions):

Payables to affiliated companies
Enron Corp:
Accounts Payable[(a)]

Income Taxes Payable[b]

(a)

Included in Accounts payable and other accruals on the Consolidated Balance Sheets

(b)

Included in Accrued taxes on the Consolidated Balance Sheets

For the Years Ended December 31				2
Expenses billed from affiliated companies				
Enron Corp:				
Intercompany services[a]				$
Expenses billed to affiliated companies				
PGH II, Inc. and its subsidiaries:				
Intercompany services[a]				

(a)

Included in Administrative and other on the Consolidated Statements of Income

Effective with the April 3, 2006 issuance of new PGE common stock, PGE is no longer a subsidiary of Enron. PGE and its subsidiaries are no longer included in Enron's consolidated tax return and file their own consolidated tax returns and remit payments directly to taxing authorities.

Enron incurred costs related to the resolution of issues associated with its bankruptcy and litigation related to certain employee benefit plans in which PGE employees previously participated. Enron billed PGE for a portion of these costs as work continued toward resolution of the issues. At December 31, 2005, PGE had $4 million payable to Enron related to these costs. Final resolution of the issues resulted in a $1 million reduction in the amount payable to Enron and a corresponding reduction in Administrative and other expense. In March 2006, PGE paid the remaining $3 million balance due to Enron.

As PGE was included in Enron's consolidated income tax return prior to April 3, 2006, the Company made payments to Enron for PGE's income tax liabilities. The $25 million income taxes payable to Enron at December 31, 2005 represents a net current income taxes payable for the fourth quarter of 2005 that was paid to Enron in January 2006. In April 2006, PGE paid Enron $17 million for net current income taxes payable for the first quarter of 2006.

In 2005, Enron billed PGE approximately $7 million for insurance coverage and costs related to the resolution of certain employee benefit plan matters (described above). In 2004, Enron billed PGE approximately $28 million, consisting of $25 million for medical/dental benefits and retirement savings plan matching and $3 million for insurance coverage.

Note 18 - Subsequent Event

On February 12, 2007, the OPUC issued an order granting a portion of PGE's request to defer excess power costs associated with the unplanned outage of the Boardman coal plant incurred from November 18, 2005 to February 5, 2006. The order authorizes the Company to defer $26.4 million, with amortization to be determined in a future ratemaking proceeding that will include a prudency review of PGE's actions with respect to the outage and acquisition of replacement power and a determination as to whether recovery of the deferred amount will cause PGE's earnings to exceed a reasonable range. In its order, the OPUC indicated that the outage was significant, unique and outside the foreseen range of risk for forced outages.

Based upon prior OPUC actions, the stated position of the OPUC staff in the proceeding, and considering the applicable accounting guidance and the impact of SB 408 on any benefit received by the Company, PGE recorded a deferral in the amount of $6 million at December 31, 2006. The remaining $20.4 million will be recorded as a reduction in power costs in 2007.

Boardman was taken out of service from October 22, 2005 to February 5, 2006 for repairs to the plant's steam turbine rotor. The extended outage required that PGE replace its portion of the plant's generation with both higher cost purchases in the wholesale market and increased generation from the Company's natural gas-fired generating plants. On November 18, 2005, PGE filed with the OPUC an "Application for Deferred Accounting of Excess Power Costs Due to Plant Outage". The application requested an order authorizing the Company to defer for later ratemaking treatment excess power costs associated with Boardman's outage during the period from the November 18, 2005 application date through February 5, 2006. The application requested deferral of approximately $46 million, representing the difference between Boardman's variable power costs used in setting rates for 2005 and 2006 (under PGE's Resource Valuation Mechanism) and replacement power costs incurred during the outage. Application by the OPUC of a sharing mechanism between PGE customers and shareholders, as well as certain reductions to PGE's estimate of the net cost of the Boardman outage, resulted in a reduction from PGE's $46 million requested deferral to the $26.4 million authorized.

QUARTERLY COMPARISON FOR 2006 AND 2005 (U

	Quarter Ended			
	March 31	June 30	September 30	December 31
	(In Millions, Except per Share Amounts)			
2006				
Operating revenues	$ 381	$ 351	$ 372	$ 416
Net operating income (a)	6	41	20	54
Net income (loss) (a)	(6)	27	10	40
Basic earnings (loss) per common share (b)	$ (0.10)	$ 0.43	$ 0.16	$ 0.64
Diluted earnings (loss) per common share (b)	$ (0.10)	$ 0.43	$ 0.16	$ 0.64
2005				
Operating revenues	$ 371	$ 333	$ 355	$ 387
Net operating income (a)	53	32	36	5

Net income (loss) (a)	38	16	19	(9)
Basic earnings (loss) per common share (b)	$ 0.61	$ 0.26	$ 0.30	$ (0.15)
Diluted earnings (loss) per common share (b)	$ 0.61	$ 0.26	$ 0.30	$ (0.15)

(a) Operating results for the fourth quarter of 2005 and first quarter of 2006 include $25 million and $26 million, respectively, after-tax effects of excess power costs incurred to replace the output of the Boardman coal plant, which was taken out of service on October 22, 2005 for repair of the plant's steam turbine rotor and which remained out of service for most of the first half of 2006. For further information, see "Boardman Coal Plant - Repair Outages" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

Operating results for the third quarter of 2006 include the $13 million after-tax effect of a reserve for a potential refund obligation to customers related to PGE's current estimate of the impact of SB 408. For further information, see "Utility Rate Treatment of Income Taxes" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

(b) Earnings per share are computed independently for each quarter presented. Therefore, 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

- Disclosure Controls and Procedures

Management of the Company, under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the Company's disclosure controls and procedures (as such term is defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of the end of the period covered by this report pursuant to Rule 13a-15(b) under the Exchange Act. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of such period, the Company's disclosure controls and procedures are effective in recording, processing, summarizing and reporting, on a timely basis, the information relating to the Company (including its consolidated subsidiaries) required to be disclosed by the Company in the reports that it files or submits under the Exchange Act and are effective in ensuring that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is accumulated and communicated to the Company's management, including the Company's Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

- Management's Report on Internal Control over Financial Reporting

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

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

Management of the Company, under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the Company's internal control over financial reporting as of the end of the period covered by this report pursuant to Rule 13a-15(c) under the Exchange Act. Management's assessment was based on the framework established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management has concluded that, as of December 31, 2006, the Company's internal control over financial reporting is effective.

Management's assessment of the effectiveness of the Company's internal control over financial reporting, as of December 31, 2006, 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 on the following page, which expresses unqualified opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting, as of December 31, 2006.

- 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 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of

Portland General Electric Company

Portland, Oregon

We have audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that Portland General Electric Company and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2006, 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 maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides 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, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2006, of the Company and our report dated March 1, 2007, expressed an unqualified opinion on those financial statements and financial statement schedule and included an explanatory paragraph regarding the adoption of Statement of Financial Accounting Standards No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*, on December 31, 2006.

Deloitte & Touche LLP

Portland, Oregon

March 1, 2007

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 - Policies on Business Ethics and Conduct," and "Proposal 1: Election of Directors - The Board of Directors" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the Securities and Exchange Commission in connection with the Annual Meeting of Shareholders to be held on May 2, 2007.

Information regarding executive officers of PGE is set forth in Part I in accordance with General Instruction G(3), pursuant to Instruction 3 to Item 401(b) of Regulation S-K.

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 "Compensation Discussion and Analysis" and "Executive Compensation" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the Securities and Exchange Commission in connection with the Annual Meeting of Shareholders to be held on May 2, 2007.

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 caption "Security Ownership of Certain Beneficial Owners, Directors and Executive Officers," in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the Securities and Exchange Commission in connection with the Annual Meeting of Shareholders to be held on May 2, 2007.

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 - Certain Relationships and Related Person Transactions" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the Securities and Exchange Commission in connection with the Annual Meeting of Shareholders to be held on May 2, 2007.

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 Securities and Exchange Commission in connection with the Annual Meeting of Shareholders to be held May 2, 2007.

Part IV

Item 15. Exhibits, Financial Statement Schedules

(a) Index to Financial Statements and Financial Stateme

Financial Statements

Financial Statement Schedule

Exhibits

See Exhibit Index on Page 149 of this report.

Portland General Electric Company and Subsidiaries

Schedule II - Consolidated Valuation and Qualifying Accounts

For the Years Ended December 31, 2006, 2005, and 2004

(In Millions)

		Allowance for Uncollectible Accounts	
Balance at January 1, 2004	$	124	
Provision charged to income		11	
Amounts written off, less recoveries		(85	)
Balance at December 31, 2004		50	
Balance at January 1, 2005		50	
Provision charged to income		7	
Amounts written off, less recoveries		(7	)
Balance at December 31, 2005		50	
Balance at January 1, 2006		50	
Provision charged to income		7	
Allowance transferred to Assets from price risk management activities		(5	)
		(7	)

Amounts written off, less recoveries				
Balance at December 31, 2006		$	45	

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.

		Portland General E	
March 2, 2007		By	

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 the dates indicated.

/s/ Peggy Y. Fowler			Chief Execu
	Peggy Y. Fowler		and Preside

			(principal ex
/s/ James J. Piro			Executive V Finance
	James J. Piro		Chief Finan
			Treasurer (principal fi accounting

*John W. Ballantine	Director
Rodney L. Brown, Jr.	Director
*David A. Dietzler	Director
*Mark B. Ganz	Director
*Corbin A. McNeill, Jr.	Director
*Neil J. Nelson	Director
*M. Lee Pelton	Director
*Maria M. Pope	Director
*Robert T.F. Reid	Director

	*By	/s/ Kirk M. Stevens
		(Kirk M. Stevens, Attorney-in-Fact)

PORTLAND GENERAL ELECTRIC COMPANY AND

SUBSIDIARIES

EXHIBIT INDEX

Number		

(3)		Articles of Incorporation and Bylaws
3.1	*	Amended and Restated Articles of Inco [Form 8-K filed April 3, 2006, Exhibit (
3.2	*	Portland General Electric Company Fo filed November 20, 2006, Exhibit (3.1)].
(4)		Instruments defining the rights of securit
4.1	*	Portland General Electric Company In July 1, 1945 [Form 8, Amendment No. 1
4.2	*	Fortieth Supplemental Indenture dated ended December 31, 1990, Exhibit (4)].
4.3	*	Forty-First Supplemental Indenture dat year ended December 31, 1991, Exhibit
4.4	*	Forty-Fifth Supplemental Indenture date June 30, 1995, Exhibit (4)].
4.5	*	Forty-Seventh Supplemental Indenture fiscal year ended December 31, 2001, Ex
4.6	*	Fifty-sixth Supplemental Indenture dat Exhibit (4)].
4.7	*	Fifty-seventh Supplemental Indentu December 21, 2006, Exhibit (4)].

		Certain instruments defining the rights omitted pursuant to Item 601(b)(4)(iii) authorized under each such omitted ins assets of PGE and its subsidiaries on a c copy of any such instrument to the SEC
(10)		Material Contracts
10.1	*	Residential Purchase and Sale Agreem [Form 10-K for the fiscal year ended De
10.2	*	Power Sales Contract and Amendatory Administration [Form 10-K for the fisca

PORTLAND GENERAL ELECTRIC COMPANY AND

SUBSIDIARIES

EXHIBIT INDEX

Number		
10.3	*	Separation A General Elect April 3, 2006
	The following 12 exhibits were filed in conjur	
10.4	*	Long-term P [Form 10-K Exhibit (10)].
10.5	*	

		Long-term T 5, 1985 [For 1985, Exhibit
10.6	*	Participation for the fiscal
10.7	*	Lease Agree the fiscal yea
10.8	*	PGE-Lessee for the fiscal
10.9	*	Asset Sales for the fiscal
10.10	*	Bargain and and Licenses fiscal year en
10.11	*	Supplementa 10-K for the (10)].
10.12	*	Trust Agreem fiscal year en
10.13	*	Tax Indemni [Form 10-K Exhibit (10)].
10.14	*	Trust Indent December 3

		December 31
10.15	*	Restated and Agreement d year ended D

PORTLAND GENERAL ELECTRIC COMPANY

AND SUBSIDIARIES

EXHIBIT INDEX

Number		
	Executive Compensation Plans and Arrangem	
10.16	*	Portland Ge Compensatio quarter ende
10.17	*	Portland Ge Executive E June 20, 200
10.18	*	Portland Ger Plan, dated Exhibit (10)]
10.19	*	Portland G Deferred Co 10-K for the
10.20	*	Portland Ge Retirement quarter ende

10.21	*	Portland Ge Insurance Be the quarter e
10.22	*	Portland Ge Managemen quarter ende
10.23	*	Portland Ge Plan [Form 8
10.24	*	Portland G Incentive M Exhibit (10.1
10.25	*	Portland Ge Deferred Co Exhibit (10.1
10.26	*	Form of Dir 8-K filed Jul
10.27	*	Form of Off 8-K filed Jul
10.28	*	Form of Off 8-K filed Jul
(23)		Consents of
23.1		Consent of I Deloitte & T

PORTLAND GENERAL ELECTRIC COMPANY

AND SUBSIDIARIES

EXHIBIT INDEX

Number		
(24)		Power of Attorney
24.1		Power of Attorney (filed herewit
(31)		Rule 13a-14(a)/15d-14(a) Certifi
31.1		Certification of Chief Executiv (filed herewith).
31.2		Certification of Chief Financia (filed herewith).
(32)		Section 1350 Certifications
32		Certifications of Chief Executiv General Electric Company Pu pursuant to Section 906 of the S
* Incorporated by reference as indicated.		
Note:		The Exhibits furnished to the Form 10-K will be supplied upo for reproduction costs. Requests Kirk M. Stevens Controller and Assistant Treasur Portland General Electric Comp

		121 SW Salmon Street, 1WTC 0 Portland, OR 97204