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

FORM 10-Q

[X] **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended June 30, 2007
OR
[ ] **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Transition period from _____v___________ to _______________

Commission File Number 1-5532-99

PORTLAND GENERAL ELECTRIC COMPANY

(Exact name of registrant as specified in its charter)

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

121 SW Salmon Street, Portland, Oregon 97204
(Address of principal executive offices) (zip code)

Registrant's telephone number, including area code: **(503) 464-8000**

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer [ ] Accelerated filer [X] Non-accelerated filer [ ]

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

Number of shares of Common Stock outstanding as of July 31, 2007: 62,516,712 shares of common stock, no par value.

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Definitions

Biglow Canyon	Biglow Canyon Wind Farm
Boardman	Boardman Coal Plant
Chapter 11 Plan	Fifth Amended Joint Plan of Affiliated Debtors Pursuant to Chapter 11 of the United States Bankruptcy Code, dated January 9, 2004 and as thereafter amended and supplemented from time to time
Colstrip	Colstrip Units 3 and 4 Coal Plant
Debtors	Enron Corp. and its reorganized debtor subsidiaries under the Chapter 11 Plan
DEQ	Oregon Department of Environmental Quality
EITF	Emerging Issues Task Force of the Financial Accounting Standards Board
Enron	Enron Corp., as reorganized debtor pursuant to its Supplemental Modified Fifth Amended Joint Plan of Affiliated Debtors Pursuant to Chapter 11 of the Bankruptcy Code, confirmed by the United States Bankruptcy Court for the Southern District of New York (Case No. 01-16034) on July 15, 2004 and effective November 17, 2004
EPA	Environmental Protection Agency
ESS	Energy Service Supplier
FERC	Federal Energy Regulatory Commission
kWh	Kilowatt-Hour
Mill	One tenth of one cent
MW	Megawatt
MWh	Megawatt-hour
NVPC	Net variable power costs
OPUC	Public Utility Commission of Oregon
PCAM	Power Cost Adjustment Mechanism
PGE or the Company	Portland General Electric Company
Port Westward	Port Westward Generating Plant
SEC	Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board
Trojan	Trojan Nuclear Plant

PART I

Financial Information

Item 1. Financial Statements

Portland General Electric Company and Subsidiaries
Condensed Consolidated Statements of Income
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	**2006**	**2007**	**2006**
	(In Millions, Except per Share Amounts)			
Operating Revenues	$ 402	$ 351	$ 838	$ 732
Operating Expenses				
Purchased power and fuel	175	143	378	375
Production and distribution	41	33	73	69
Administrative and other	45	45	90	79
Depreciation and amortization	43	53	88	110
Taxes other than income taxes	19	18	40	38
Income taxes	23	18	49	14
	346	310	718	685
Net Operating Income	56	41	120	47
Other Income (Deductions)				
Allowance for equity funds used during construction	4	4	9	7
Miscellaneous	4	(2)	8	(2)
Income taxes	-	-	(1)	1
	8	2	16	6
Interest Charges				
Interest on long-term debt and other	18	16	35	32
Net Income	$ 46	$ 27	$ 101	$ 21
Common Stock:				
Weighted-average shares outstanding (thousands), Basic	62,507	62,500	62,506	62,500
Weighted-average shares outstanding (thousands), Diluted	62,536	62,500	62,531	62,500
Earnings per share, Basic and Diluted	$ 0.73	$ 0.43	$ 1.61	$ 0.34
Dividends declared per share	$ 0.235	$ 0.225	$ 0.46	$ 0.225

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

Portland General Electric Company and Subsidiaries
Condensed Consolidated Statements of Retained Earnings
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	**2006**	**2007**	**2006**
		(In Millions)		
Balance at Beginning of Period	$ 628	$ 552	$ 587	$ 558
Net Income	46	27	101	21
	674	579	688	579
Dividends Declared - Common Stock	15	14	29	14
Balance at End of Period	$ 659	$ 565	$ 659	$ 565

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

Portland General Electric Company and Subsidiaries
Condensed Consolidated Statements of Comprehensive Income
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	**2006**	**2007**	**2006**
	(In Millions)			
Accumulated other comprehensive income (loss) - Beginning of Period				
Unrealized gain (loss) on derivatives classified as cash flow hedges	$ -	$ (2)	$ -	$ -
Minimum pension liability adjustment	*	(3)	*	(3)
Pension and other post-retirement plan's funded position	(6)	*	(6)	*
Total	$ (6)	$ (5)	$ (6)	$ (3)
Net Income	$ 46	$ 27	$ 101	$ 21
Other comprehensive income, net of tax:				
Unrealized gains (losses) on derivatives classified as cash flow hedges:				
Other unrealized holding net gains (losses) arising during the period, net of related taxes of $2 and $(5) for the three months ended June 30, 2007 and 2006 and $13 for the six months ended June 30, 2006	(3)	7	-	(19)
Reclassification adjustment for contract settlements included in net income, net of related taxes of $(1) for the three months ended June 30, 2006 and $3 for the six months ended June 30, 2007 and 2006	-	1	(4)	(7)
Reclassification of unrealized gains (losses) to SFAS No. 71 regulatory (liability) asset, net of related taxes of $(2) and $5 for the three months ended June 30, 2007 and 2006 and $(3) and $(16) for the six months ended June 30, 2007 and 2006	3	(8)	4	24
Total - Unrealized gains (losses) on derivatives classified as cash flow hedges	-	-	-	(2)
Minimum pension liability adjustment	*	-	*	-
Pension and other post-retirement plan's funded position, net of related taxes of $(1) for the three months ended June 30, 2007	1	*	-	*
Reclassification of defined benefit pension plan and other benefits to SFAS No. 71 regulatory asset, net of related taxes of $1 for the three months ended June 30, 2007	(1)	*	-	*
Total Other comprehensive income (loss)	-	-	-	(2)
Comprehensive income	$ 46	$ 27	$ 101	$ 19
Accumulated other comprehensive income (loss) - End of Period				
Unrealized gain (loss) on derivatives classified as cash flow hedges	$ -	$ (2)	$ -	$ (2)
Minimum pension liability adjustment	*	(3)	*	(3)
Pension and other post-retirement plan's funded position	(6)	*	(6)	*
Total	$ (6)	$ (5)	$ (6)	$ (5)

* With the adoption of SFAS No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, at December 31, 2006, certain information is no longer applicable. Similarly, certain information for 2007 was not previously applicable.

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

Portland General Electric Company and Subsidiaries
Condensed Consolidated Balance Sheets
(Unaudited)

	June 30, 2007	December 31, 2006
	(In Millions)	
Assets		
Electric Utility Plant - Original Cost		
Utility plant (includes construction work in progress of $255 and $412)	$ 4,801	$ 4,582
Accumulated depreciation	(1,909)	(1,864)
	2,892	2,718
Other Property and Investments		
Nuclear decommissioning trust, at market value	43	42
Non-qualified benefit plan trust	72	70
Miscellaneous	31	26
	146	138
Current Assets		
Cash and cash equivalents	42	12
Accounts and notes receivable (less allowance for uncollectible accounts of $5 and $45)	163	177
Unbilled revenues	66	88
Assets from price risk management activities	78	93
Inventories, at average cost	65	64
Margin deposits	12	46
Prepayments and other	27	25
Deferred income taxes	12	22
	465	527
Deferred Charges		
Regulatory assets	357	351
Miscellaneous	34	33
	391	384
	$ 3,894	$ 3,767
Capitalization and Liabilities		
Capitalization		
Common stock equity:		
Common stock, no par value, 80,000,000 shares authorized; 62,510,033 and 62,504,767 shares outstanding at June 30, 2007 and December 31, 2006, respectively	$ 644	$ 643
Retained earnings	659	587
Accumulated other comprehensive income (loss):		
Pension and other post-retirement plans	(6)	(6)
Long-term debt	1,108	937
	2,405	2,161
Commitments and Contingencies (see Notes)		
Current Liabilities		
Long-term debt due within one year	-	66
Short-term borrowings	-	81
Accounts payable and other accruals	245	212
Liabilities from price risk management activities	113	155
Customer deposits	5	5
Accrued interest	16	15
Accrued taxes	19	14
Dividends payable	15	14
	413	562
Other		
Deferred income taxes	259	251
Deferred investment tax credits	5	7
Trojan asset retirement obligation	110	108
Accumulated asset retirement obligation	25	26
Regulatory liabilities:		
Accumulated asset retirement removal costs	434	411
Other	106	112
Non-qualified benefit plan liabilities	87	84
Miscellaneous	50	45
	1,076	1,044
	$ 3,894	$ 3,767

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

Portland General Electric Company and Subsidiaries
Condensed Consolidated Statements of Cash Flows
(Unaudited)

	Six Months Ended June 30, 2007	2006
	(In Millions)	
Cash Flows From Operating Activities:		
Reconciliation of net income to net cash provided by operating activities		
Net income	$ 101	$ 21
Non-cash items included in net income:		
Depreciation and amortization	88	110
Deferred income taxes	18	(31)
Net assets from price risk management activities	(34)	92
Power cost deferral	(21)	-
Regulatory deferrals - price risk management activities	34	(67)
Other non-cash income and expenses (net)	(22)	4
Changes in working capital:		
Net margin deposit activity	34	(48)
Decrease in receivables	37	84
(Decrease) in payables	(25)	(109)
Other working capital items - net	(3)	(14)
Other - net	(6)	4
Net Cash Provided by Operating Activities	201	46
Cash Flows From Investing Activities:		
Capital expenditures	(159)	(211)
Purchases of nuclear decommissioning trust securities	(10)	(20)
Sales of nuclear decommissioning trust securities	9	10
Other - net	(5)	5
Net Cash Used in Investing Activities	(165)	(216)
Cash Flows From Financing Activities:		
Short-term borrowings (repayments) - net	(81)	-
Repayment of long-term debt	(71)	(158)
Issuance of long-term debt	176	275
Debt issue costs	(2)	-
Dividends paid	(28)	-
Net Cash Provided by (Used in) Financing Activities	(6)	117
Increase (Decrease) in Cash and Cash Equivalents	30	(53)
Cash and Cash Equivalents, Beginning of Period	12	122
Cash and Cash Equivalents, End of Period	$ 42	$ 69
Supplemental disclosures of cash flow information		
Cash paid during the period:		
Interest, net of amounts capitalized	$ 21	$ 29
Income taxes	29	42
Non-cash activities:		
Accrued capital additions	84	22
Common stock dividends declared but not paid	15	14

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

Notes to Condensed Consolidated Financial Statements (Unaudited)

Note 1 - Principles of Interim Statements

The interim financial statements have been prepared by Portland General Electric Company (PGE or the Company) and, in the opinion of management, reflect all adjustments which are necessary for a fair presentation of the results for the interim periods presented. All such adjustments are of a normal recurring nature. Such statements, which are unaudited, are presented in accordance with the interim reporting requirements of the Securities and Exchange Commission (SEC), which do not include all the disclosures required by accounting principles generally accepted in the United States of America for annual financial statements. Certain information and footnote disclosures made in the last annual report on Form 10-K have been condensed or omitted for the interim statements. Certain costs are estimated for the full year and allocated to interim periods based on estimates of operating time expired, benefit received, or activity associated with the interim period; accordingly, such costs may not be reflective of amounts to be recognized for a full year. Due to seasonal fluctuations in electricity sales, as well as the price of wholesale energy and natural gas costs, interim financial results do not necessarily represent those to be expected for the year. It is management's opinion that, when the interim statements are read in conjunction with the Company's 2006 Annual Report on Form 10-K filed with the SEC, the disclosures are adequate to make the information presented not misleading.

Reclassifications - Certain amounts in prior year financial statements have been reclassified for comparative purposes. Specifically, amounts representing "Allowance for equity funds used during construction", previously classified within "Other Income (Deductions) - Miscellaneous" on the Condensed Consolidated Statements of Income, are now reported separately. These reclassifications had no effect on PGE's previously reported consolidated financial position, results of operations, or cash flows.

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.

Non-Qualified Benefit Plans - The amounts included under 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 and marketable securities, are intended to be the primary source for financing these plans.

Other Benefits - PGE also participates in non-contributory post-retirement health and life insurance plans ("Other Benefits" in the table below). 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 addition, PGE has established Health Retirement Accounts (HRAs) for its employees under which the Company makes contributions to trust accounts to provide for claims by retirees for qualified medical costs.

The measurement date for these plans is December 31. PGE does not expect to make contributions to the pension plan, SERP, or post-retirement health and life insurance plans during 2007; contributions to the HRAs are not expected to be material.

The following table reflects the components of net periodic benefit cost for the periods indicated (in millions):

Three Months Ended June 30:	**Defined Benefit Pension Plan**		**Non-Qualified Benefit Plans**		**Other Benefits**	
	2007	**2006**	**2007**	**2006**	**2007**	**2006**
Components of net periodic benefit cost:						
Service cost	$ 3	$ 3	$ -	$ -	$ 1	$ -
Interest cost on benefit obligation	7	7	1	-	1	1
Expected return on plan assets	(11)	(10)	(1)	(1)	-	-
Recognized (gain) loss	1	1	-	1	-	-
Net periodic benefit cost (income)	$ -	$ 1	$ -	$ -	$ 2	$ 1

Six Months Ended June 30:	**Defined Benefit Pension Plan**		**Non-Qualified Benefit Plans**		**Other Benefits**	
	2007	**2006**	**2007**	**2006**	**2007**	**2006**
Components of net periodic benefit cost:						
Service cost	$ 6	$ 6	$ -	$ -	$ 1	$ -
Interest cost on benefit obligation	14	14	1	-	2	2
Expected return on plan assets	(21)	(20)	(1)	(1)	-	-
Recognized (gain) loss	2	2	-	1	-	-
Net periodic benefit cost (income)	$ 1	$ 2	$ -	$ -	$ 3	$ 2

Note 3 - 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 Statement of Financial Accounting Standards (SFAS) No. 133, Accounting for Derivative Instruments and Hedging Activities (as amended), derivative instruments are recorded on the Balance Sheet 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 Emerging Issues Task Force Issue (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 Other Comprehensive Income (OCI) until they can offset the related results on the hedged item in the Income Statement. The derivative instruments entered into to manage 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, Accounting for the Effects of Certain Types of Regulation.

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 Resource Valuation Mechanism (RVM). Upon settlement, the regulatory asset or regulatory liability was reversed. In its January 2007 general rate order, the Public Utility Commission of Oregon (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 (NVPC) 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 reflects unrealized gains and losses recorded in earnings for the periods indicated (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Non-Trading Activities				
Unrealized gains (losses)	$ (7)	$ (13)	$ 34	$ (92)
SFAS No. 71 regulatory asset (liability)	7	9	(34)	67
Net unrealized gains (losses)	$ -	$ (4)	$ -	$ (25)

The following table reflects derivative activities from cash flow hedges recorded in OCI (before taxes) for the periods indicated (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Derivative Activities Recorded in OCI				
Unrealized holding net gains (losses) arising during the period	$ (5)	$ 12	$ -	$ (32)
Reclassification adjustment for contract settlements included in net income	-	2	(7)	(10)
Reclassification of unrealized (gains) losses to SFAS No. 71 regulatory (liability) asset	5	(13)	7	40
Total - Unrealized gains (losses) on derivatives classified as cash flow hedges	$ -	$ 1	$ -	$ (2)

Hedge ineffectiveness from cash flow hedges was not material in the first six months of 2007 and 2006. As of June 30, 2007, the maximum length of time over which PGE is hedging its exposure to such transactions is approximately 51 months. The Company estimates that of the $2 million of net unrealized losses in OCI at June 30, 2007, $6 million in net unrealized losses will be reclassified into earnings within the next twelve months (fully offset by SFAS No. 71 regulatory assets) and $4 million in net unrealized gains will be reclassified over the remaining 39 months (fully offset by SFAS No. 71 regulatory liabilities).

Note 4 - 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 Oregon Court of Appeals decision were pending at the Oregon Supreme Court, PGE, CUB, and the staff of the OPUC entered into agreements to settle the litigation related to PGE's recovery of, and return on, its investment in the Trojan plant. The URP did not participate in the settlement. The settlement, which was approved by the OPUC in September 2000, allowed PGE to remove from its balance sheet the remaining before-tax investment in Trojan of approximately $180 million at September 30, 2000, along with several largely offsetting regulatory liabilities. 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.

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. 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.

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.

In Order No. 07-157 (the Order) entered on April 19, 2007, the OPUC denied the motion PGE filed in November 2006 to consolidate phases and re-open the record. In addition, the Order abated the Phase I proceeding pending a decision by the Oregon Court of Appeals of the 2003 Remand, and ordered that a second phase of the joint remand proceedings be immediately commenced to investigate the OPUC's delegated authority to engage in retroactive ratemaking. The Order further stated that parties not now participating in the joint remand proceedings will be allowed to intervene and participate in the second phase. The parties have submitted final briefs and oral argument is scheduled for August 9, 2007.

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.

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 and 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, PGE 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 investigation by the Environmental Protection Agency (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 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 Oregon Department of Environmental Quality (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 a 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 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 condition, results of operations or cash flows.

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, 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 (RI/FS) from the EPA, dated June 27, 2005, in which the Company was named as one of fourteen PRPs with respect to the Harbor Oil site. The letter started a period for the PRPs to participate in negotiations with the EPA to reach a settlement to conduct or finance an RI/FS of the Harbor Oil site. On May 31, 2007, an Administrative Order on Compliance was signed by the EPA and six other parties, including PGE, to implement an RI/FS at the Harbor Oil site.

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

Note 5 - Receivables and Refunds on Wholesale Market Transactions

On May 17, 2007, the Federal Energy Regulatory Commission (FERC) approved a March 12, 2007 settlement (the May 17 Settlement) among PGE, the California Attorney General, the California Department of Water Resources, the California Electricity Oversight Board, the California Public Utilities Commission, Southern California Edison Company, Pacific Gas & Electric Company, and San Diego Gas & Electric Company that resolved all issues between the parties relating to wholesale energy transactions in the western markets during the January 1, 2000 through June 20, 2001 time period. The settlement resolved a number of proceedings and investigations before the FERC and the U.S. Ninth Circuit Court of Appeals relating to various issues and claims in the California refund case (Docket No. EL00-95), the issue of refunds for the summer 2000 period, investigations of anomalous bidding activities and market practices (Docket Nos. IN03-10-000 and EL03-165-000), claims for refunds related to sales in the Pacific Northwest (Docket No. EL01-10), and the complaint by the California Attorney General for refunds from market-based rates retroactively to May 1, 2000.

Certain other market participants have now joined the May 17 Settlement, but releases as to those parties do not cover transactions outside of the California organized markets, including potential claims in the Pacific Northwest. The rights of parties electing not to join the settlement are unaffected and they will neither receive the benefits of the settlement nor be subject to its obligations. PGE believes that any amount that it may owe to non-settling parties related to transactions in the California organized market would not be material to the Company's financial condition, results of operations or cash flows.

Pursuant to the terms of the May 17 Settlement, PGE received a cash payment from the California Power Exchange (PX) of approximately $28 million (including net interest on the Company's past due receivables) in June 2007 and adjusted the reserve related to this matter to zero at June 30, 2007. Based upon previously-recorded reserves and the terms of the May 17 Settlement, PGE recorded a pre-tax increase to income of approximately $6 million in the first quarter of 2007 (reflected as a reduction to Purchased Power and Fuel expense).

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 Federal Power Act (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. Petitions for rehearing at the Ninth Circuit and for U.S. Supreme Court review have been denied.

In the refund case and in related dockets, including the above challenge to market-based rates, the California Attorney General and other parties have argued that refunds should be ordered retroactively to at least May 1, 2000. The May 17 Settlement in the California refund case described above resolves all claims as to market-based rates in western energy markets as between PGE and the named California parties and PGE and the opt-in participants during the settlement period, January 1, 2000 through June 21, 2001; however, it does not settle such claims from market participants who do not opt-in to the settlement, nor does it settle such potential claims arising from transactions with other market participants outside of the California Independent System Operator and PX markets. 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. However, management believes that the outcome will not have a material adverse impact on the Company's financial condition, results of operations or cash flows.

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.

The May 17 Settlement in the California refund case described above resolves all claims as between PGE and the named California parties as to transactions in the Pacific Northwest during the settlement period, January 1, 2000 through June 21, 2001; however, it does not settle such potential claims from other market participants.

Management cannot predict the ultimate outcome of the above matter related to wholesale transactions in 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 6 - Utility Rate Treatment of Income Taxes

An Oregon 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 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.

The OPUC has adopted rules to implement SB 408. The rules include the use of fixed reference points for margins and effective tax rates from a ratemaking proceeding. The rules also include 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 its 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 its 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. The Oregon legislature did not address this issue in the 2007 legislative session and it is uncertain whether it will be considered in the future. Accordingly, the ultimate outcome of this matter is not certain.

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 OPUC 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.

PGE has estimated its potential refunds to customers to be approximately $42 million (including $2 million of accrued interest) for 2006 and recorded a (pre-tax) reserve of such amount for the year. (The reserve includes $17 million paid to Enron for net current taxes payable for the first quarter of 2006 when PGE was included in its former parent's consolidated group for filing consolidated federal and state income tax returns). Interest will continue to accrue on the reserve, with an additional $2 million recorded in the first half of 2007. In accordance with the statute, PGE 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. Under the OPUC rules, any refunds to customers for the 2006 tax year would begin after June 1, 2008.

For the year 2007, PGE estimates a potential collection from customers of approximately $10 million. Based on a percentage of estimated annual revenues collected in the first half of the year, PGE deferred, as a regulatory asset, approximately $5 million (including accrued interest) at June 30, 2007. Any collections from, or refunds to, customers for the 2007 tax year will be reported in the Company's October 15, 2008 filing with the OPUC.

PGE is participating in an OPUC rulemaking process to resolve certain issues related to the application of SB 408 rules. A procedural schedule has been established, with completion of the process expected by September 2007.

Complaint and Application for Deferral - Income Taxes - On October 5, 2005, the URP and Ken Lewis (together, the 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 7 - Common Stock

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. The 42.8 million shares of PGE common stock previously held by Enron were cancelled. 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 were held and were being released over time to the Debtors' creditors holding allowed claims, in accordance with the Chapter 11 Plan. In June 2007, substantially all of the remaining shares of PGE's common stock held by the DCR were sold in a public offering.

In addition to the issuance of the 62.5 million shares of new PGE common stock described above, 4.7 million and 625,000 shares, respectively, have been registered for future issuance pursuant to the Portland General Electric Company 2006 Stock Incentive Plan and 2007 Employee Stock Purchase Plan.

Employee Stock Purchase Plan

In May 2007, PGE shareholders approved the Portland General Electric Company 2007 Employee Stock Purchase Plan (ESPP). The ESPP permits all eligible Company employees to purchase shares of PGE common stock through regular payroll deductions, which are limited to 10% of base pay. Each year, employees may purchase up to a maximum of $25,000 worth of stock (based on fair market value on the purchase date) or 1,500 shares, whichever is less. Each year during the term of the ESPP there will be two six-month offering periods, during which eligible employees will have the right to purchase shares of PGE common stock at a price per share equal to 95% of the fair market value of the stock on the purchase date. The offering periods will run from January 1 through June 30 and from July 1 through December 31, with shares purchased at the end of each offering period. The first offering period began on July 1, 2007.

Common Stock Dividend Restrictions

The OPUC order that approved the issuance of new PGE common stock includes a stipulation containing several conditions, including a requirement that the OPUC approve the payment of dividends that reduce the Company's common equity capital percentage below certain levels, depending upon the percentage of issued and outstanding common stock held by the DCR. With the DCR's sale of substantially all of its PGE common stock in June 2007, this requirement is no longer applicable.

Dividends on Common Stock

The following table indicates common stock dividends declared in 2007:

Declaration Date	Record Date	Payment Date	Dividends Declared per Common Share
February 22, 2007	March 26, 2007	April 16, 2007	$0.225
May 2, 2007	June 25, 2007	July 16, 2007	$0.235

Note 8 - Stock-Based Compensation

In 2006, PGE adopted the Portland General Electric Company 2006 Stock Incentive Plan (the Plan). Under the Plan, PGE may grant a variety of equity based awards, including restricted stock units with time-based vesting conditions (Restricted Stock Units) and performance-based vesting conditions (Performance Stock Units) to non-employee directors, officers and certain key employees. A total of 4,687,500 shares of common stock were registered for future issuance under the Plan.

On March 15, 2007, PGE granted 83,410 Performance Stock Units to officers and certain key employees and 5,600 Restricted Stock Units to certain key employees of the Company. PGE also granted 1,089 Restricted Stock Units to a key employee on June 13, 2007. 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. The grants provide for the payment of one Dividend Equivalent Right (DER) for each stock unit. A DER entitles the grantee to receive an amount equal to dividends paid on a share of PGE's common stock, which dividends have a record date between the grant date and the vesting date of the DERs. 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. The Restricted Stock Unit DERs are settled in shares of PGE common stock valued at each dividend payment date and vest on the same schedule as the Restricted Stock Units.

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 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.

Also on March 15, 2007, a grant of 525 Restricted Stock Units, valued at $15,000, was made to a newly elected director. The grant vested in equal installments on March 31, 2007 and June 30, 2007 and was settled exclusively in shares of the Company's common stock.

On June 13, 2007, PGE's nine non-employee directors were granted a total of 9,801 Restricted Stock Units as part of their annual compensation arrangement. Each director was granted 1,089 units, valued at $30,000, based upon the closing stock price on the grant date. The grants vest over a one-year period in equal installments on the last day of each calendar quarter beginning September 30, 2007 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 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. The cash from the settlement of the DERs may also be deferred under the terms of the Portland General Electric Company 2006 Outside Directors' Deferred Compensation Plan.

Restricted Stock Unit activity for the first half of 2007 is summarized in the following table:

	Non-employee Directors		Officers and Key Employees	
	Units	Weighted Average Grant Date Fair Value	Units	Weighted Average Grant Date Fair Value
Restricted Stock Units:				
Stock units outstanding - December 31, 2006	4,741	$25.31	86,201	$24.96
Stock units granted:				
March 15, 2007	525	28.55	5,600	28.55
June 13, 2007	9,801	27.54	1,089	27.54
Stock units forfeited	-	-	(4,001)	25.32
Stock units vested	(5,266)	25.63	-	-
Stock units outstanding - June 30, 2007	9,801	27.54	88,889	25.20

Performance Stock Unit activity for the first half of 2007 is summarized in the following table:

	Officers and Key Employees	
	Units	Weighted Average Grant Date Fair Value
Performance Stock Units:		
Stock units outstanding - December 31, 2006	89,238	$24.96
Stock units granted - March 15, 2007	83,410	28.55
Stock units forfeited	-	-
Stock units vested	-	-
Stock units outstanding - June 30, 2007	172,648	26.69

The weighted average fair value is measured based on the closing price of PGE common stock on the date of grant. A total of 4,406,129 shares remain available for future grants. The Plan had no material impact on cash flow for the six months ended June 30, 2007.

For the six months ended June 30, 2007, PGE recorded $1.3 million of stock-based compensation expense (included in Administrative and other expense in the Condensed 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 $5.2 million at June 30, 2007, of which $1.4 million, $2.6 million, and $1.2 million is expected to be expensed in 2007, 2008, and 2009, respectively.

Note 9 - Earnings Per Share

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Numerator:				
Net Income (in millions)	$ 46	$ 27	$ 101	$ 21
Denominator (in thousands):				
Weighted-average common shares outstanding-basic	62,507	62,500	62,506	62,500
Effect of dilutive securities:				
Restricted Stock*	29	-	25	-
Weighted-average common shares outstanding-diluted	62,536	62,500	62,531	62,500
Earnings per share - basic	$ 0.73	$ 0.43	$ 1.61	$ 0.34
Earnings per share - diluted	$ 0.73	$ 0.43	$ 1.61	$ 0.34

* Restricted Stock Units and related Dividend Equivalent Rights granted under the Portland General Electric Company 2006 Stock Incentive Plan are discussed in Note 8, Stock-Based Compensation. Unvested Performance Stock Units are not included in the computation of dilutive securities because the units are subject to a three-year performance period.

Note 10 - Credit Facility and Debt

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, which has been extended for one additional year, to July 13, 2012. The amount available under the commercial paper program is limited to the unused line of credit under the revolving credit facility. The facility contains customary covenants and default provisions, including a requirement that limits consolidated indebtedness, as defined in the facility, to 65% of total capitalization. At June 30, 2007, PGE was in compliance with these covenants.

Although the commercial paper program subjects the Company to fluctuations in interest rates, reflecting current market conditions, individual instruments carried a fixed rate during their respective terms.

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

	June 30, 2007	December 31, 2006
Aggregate short-term debt outstanding -		
Commercial paper	$ -	$ 81
Weighted average interest rate -		
Commercial paper*	-	5.5%
Unused committed line of credit	$387	$313

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Average daily amounts of short-term debt outstanding -				
Commercial paper	$ 16	$ 23	$ 28	$ 17
Weighted daily average interest rate -				
Commercial paper*	5.4%	5.0%	5.5%	4.9%
Maximum amount outstanding during the period -				
Commercial paper	$ 60	$ 57	$ 93	$ 57

*Interest rates exclude the effect of commitment fees, facility fees, and other financing fees.

On March 8, 2007, PGE remarketed $5.8 million of variable interest rate Port of Morrow Pollution Control Bonds due in 2031 under a new remarketing agreement.

On April 12, 2007, PGE and certain institutional buyers in the private placement market entered into a bond purchase agreement under which PGE agreed to sell $130 million of PGE's First Mortgage Bonds to the buyers. Funding will take place, and the bonds will transfer to the buyers, at the direction of PGE at any time up to, but not later than, October 1, 2007 (subject to five business days notification). The bonds will bear interest at an annual rate of 5.81%, and will mature on October 1, 2037. The bonds will be issued under PGE's Indenture of Mortgage and Deed of Trust, dated July 1, 1945, as supplemented, including the Fifty-eighth Supplemental Indenture dated April 1, 2007, between PGE and HSBC Bank USA, National Association 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.

On May 16, 2007, PGE received $170 million from the sale of First Mortgage Bonds to certain institutional buyers in the private placement market, pursuant to an agreement entered into in December 2006. The bonds were issued under PGE's Indenture of Mortgage and Deed of Trust, dated July 1, 1945, as amended and supplemented to date and from time to time (including the Fifty-seventh Supplemental Indenture dated December 1, 2006). The bonds bear interest at an annual rate of 5.80% and will mature on June 1, 2039. The proceeds from the sale of the bonds will be used for general corporate purposes, which may include capital expenditures and/or the repayment of existing debt.

On June 15, 2007, PGE redeemed $50 million of 7.15% First Mortgage Bonds at maturity and the remaining $16 million of 7.75% Series Cumulative Preferred Stock, which was mandatory. On June 27, 2007, the Company elected to redeem, at par value, $5.1 million of 7 1/8% Port of St. Helens Pollution Control Bonds due in 2014.

Note 11 - Guarantees

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 Condensed 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 12 - Income Taxes

PGE adopted FASB Interpretation No. 48 (FIN 48), Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109, on January 1, 2007. 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 before the benefit of an uncertain tax position can 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 its technical merits.

PGE has completed an assessment of FIN 48 with respect to the Company's income tax positions. Based on such assessment, PGE has not recorded any liability for uncertain tax positions. Any interest or penalties on any future income tax deficiencies would be recorded within Interest Charges or Other Deductions, respectively, in the Company's Condensed Consolidated Statements of Income.

PGE files income tax returns in the U.S federal jurisdiction, in the states of Oregon and Montana, and in Multnomah County, Oregon. The Company is not currently under examination by federal, state or local tax authorities. Open tax years include 2004 and subsequent years for federal tax purposes and 2003 and subsequent years for state and local tax purposes.

Note 13 - Power Cost Adjustment Mechanism

Effective January 17, 2007, the OPUC approved a new PCAM by which PGE can adjust future rates to reflect the difference between each year's forecasted NVPC included in rates (the baseline), and actual NVPC on a settlement basis. Under the PCAM, PGE will be subject to a portion of the business risk or benefit associated with actual NVPC varying from costs included in base rates by: (1) applying an asymmetrical deadband for PGE to absorb cost increases or decreases, with a 90/10 sharing of costs and benefits between customers and the Company, respectively, beyond the deadband, and (2) employing a regulated earnings test.

The asymmetrical deadband is based on 75 basis points below and 150 basis points above PGE's authorized return on equity (ROE), or approximately $(11.7) million and $23.4 million, respectively, for 2007. The Annual Variance is defined as the difference between actual NVPC and baseline NVPC. An Annual Power Cost Variance (PCV), defined as 90% of the Annual Variance outside the deadband, is recorded as a customer refund or collection (subject to a regulated earnings test). The following table summarizes the approximate PCAM deadband for 2007 (in millions):

Annual Variance Amount	PCV Deferral for Refund or Collection
If more than $(11.7) below baseline - refund................	90% of Annual Variance in excess of $(11.7)
Between $(11.7) and $23.4..	No deferral
If more than $23.4 above baseline - collection.............	90% of Annual Variance in excess of $23.4

The refund or collection amount will be subject to a regulated earnings test for the year that the NVPC were incurred. The customer refund amount will be limited to the extent that such refund will not cause PGE's actual regulated ROE for the year to fall below its authorized ROE plus 100 basis points, or 11.1%. Conversely, the customer collection amount will be limited to the extent that such collection will not cause PGE's actual regulated ROE for the year to exceed its authorized ROE minus 100 basis points, or 9.1%. A regulatory asset or liability will be recorded, with the offset to Purchased Power and Fuel expense, for any PCV deferral that arises. Interest will accrue on any deferral at the Company's authorized rate of return.

As of June 30, 2007, the year-to-date Annual Variance is $14.8 million below the baseline. Since this variance amount exceeded the $(11.7) million deadband, a $2.8 million regulatory liability was recorded for the second quarter of 2007. Any regulatory asset or liability arising from the deadband calculation would be adjusted by a regulated earnings test calculation at year end. Final determination of any refund or collection amount would be determined by the OPUC through a public filing and review.

Annually, the Company will propose PCV adjustment rates that will amortize the PCV to customer rates. The OPUC will make the final determination regarding such rates and the period over which they would apply.

In addition, as part of its Order No. 07-015, issued on January 12, 2007, the OPUC adopted an Annual Power Cost Update Tariff, which replaces the Resource Valuation Mechanism. The Annual Power Cost Update Tariff provides for rate adjustments to reflect updated forecasts of NVPC for future calendar years. The approved Annual Power Cost Update Tariff establishes the new baseline NVPC for purposes of the PCAM calculation each year. On July 11, 2007, PGE submitted to the OPUC an update of its 2008 NVPC forecast. The Company projects an approximate 2% average increase in customer rates, effective January 1, 2008. A final 2008 NVPC forecast will be submitted to the OPUC in the fourth quarter of 2007.

Note 14 - Port Westward Generating Plant

On June 11, 2007, the Port Westward Generating Plant (Port Westward), a 400 MW natural gas-fired facility located in Clatskanie, Oregon, was placed into service. Total cost of the new plant through June 30, 2007 was approximately $280 million (including allowance for funds used during construction).

In January 2007, the OPUC issued a rate order approving a 2.8% increase related to the cost recovery of Port Westward, which became effective on June 15, 2007. In the rate order, the OPUC also established a process for re-examining the rate increase if the plant's in service date was on or after May 2, 2007. The OPUC staff and intervenors were permitted, within 15 days of the in service date of the plant, to request a re-examination of the costs of Port Westward reflected in PGE's rates. The Citizens' Utility Board has requested a re-examination, while the OPUC staff has indicated its support of the new rates. If the OPUC determines that further proceedings are necessary, the additional revenues collected as a result of the rate increase would be subject to refund, pending the outcome of the proceedings and any required rate adjustment. If there is no determination that further proceedings are necessary, the new rates are expected to remain in effect.

Note 15 - New Accounting Standards

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 financial assets and liabilities.

FASB Staff Position No. 39-1 (FSP FIN 39-1), Amendment of FASB Interpretation No. 39 (FIN 39), was issued in April 2007 and is effective for fiscal years beginning after November 15, 2007. FSP FIN 39-1 modifies FIN 39, Offsetting of Amounts Related to Certain Contracts, and permits reporting entities to offset the receivable or payable recognized upon payment or receipt of cash collateral against fair value amounts recognized for derivative instruments that have been offset under a master netting arrangement. FSP FIN 39-1 requires financial statement disclosure of a reporting entity's accounting policy (to offset or not offset) as well as amounts recognized for the right to reclaim cash collateral, or the obligation to return cash collateral, that have been offset against net derivative positions. PGE is evaluating the application of FSP FIN 39-1 with respect to its assets and liabilities.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

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. Portland General Electric's (PGE or the Company) 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 (NVPC) and other capital investments, and present or prospective wholesale and retail competition;

- the effects of Oregon law related to utility rate treatment of income taxes (SB 408), which may result 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;

- final resolution of matters related to the Bonneville Power Administration Residential Exchange Program payments;

- 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 failure to complete major generating plants on schedule and within budget;

- weather conditions that directly influence customer demand for electricity and damage to PGE facilities from major storms;

- 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 local, national, and international concerns regarding global warming and climate change, including 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.

Overview

General - PGE maintains its focus on providing safe and reliable electric service to its customers and achieving strong financial performance. The ongoing strength of Oregon's economy has contributed to customer growth and increasing demand for electricity within the Company's service territory. The Company continues to pursue its commitment to renewable energy as it proceeds with construction of new wind generation facilities at the Biglow Canyon Wind Farm. Such efforts align with Oregon's new Renewable Energy Standard, adopted by the 2007 legislature, which requires that PGE and other large electricity providers serve at least 25% of their retail load from renewable resources by the year 2025. PGE will continue to explore new generating resources and additional energy efficiency opportunities, consistent with its Integrated Resource Plan (IRP), to meet the growing energy needs of customers. For further information, see "Integrated Resource Plan" and "Renewable Energy Standard" in "Financial and Operating Outlook" of this Item 2.

The most recent Oregon biennial legislative session included additional enacted legislation that could affect PGE or its customers. Among the actions taken were an expansion of the Business Energy Tax Credit program, a mechanism for financing customer-owned renewable energy generation facilities, goals for statewide carbon emission reductions, a requirement that the Environmental Quality Commission revise the manner in which it adopts rules that are stricter than federal rules, and dedication of refunds under the provisions of the corporate income tax kicker for a "rainy day" account.

On June 18, 2007, the Enron Disputed Claims Reserve (DCR) sold substantially all of its remaining holdings of PGE common stock in a public offering, with all of PGE's common stock now publicly traded. For further information, see "Ownership of PGE" in "Financial and Operating Outlook" of this Item 2.

Customers - Oregon's economy continued to expand in the first half of 2007, with the state's 5.0% seasonally adjusted unemployment rate in May the lowest since April 2000. Oregon's non-farm employment (seasonally adjusted) reached a new record high in May 2007, 1.2% above a year ago. Sustained economic growth is expected to require continued investment in generation, transmission and distribution facilities to meet increased energy requirements of PGE's customers.

Total retail energy deliveries for the first half of 2007 increased 1.3% over the same period in 2006 primarily as the result of customer growth. On a weather adjusted basis, retail energy deliveries are up 1.2% from last year. Energy use by all major customer sectors increased in the first half of this year.

The Company added over 11,200 new customers during the past twelve months and now serves approximately 802,000 retail customers. PGE continues to rank well for overall customer satisfaction and recently launched a multi-year effort to increase customer satisfaction and seek input from customers on the Company's decisions and actions.

On May 21, 2007, the Bonneville Power Administration (BPA) notified PGE and six other investor-owned utilities (IOUs) in the Pacific Northwest that it was immediately suspending the Residential Exchange Program payments that the IOUs pass through to their residential and small farm customers in the form of monthly billing credits. Through June 30, 2007, approximately $47 million in benefits had been received by PGE customers. Because these benefits are received from BPA and passed through to PGE's customers, the outcome of this matter is not expected to have a significant effect on the Company's financial results. For further information, see "Residential Exchange Program" in "Financial and Operating Outlook" of this Item 2.

The suspension of such benefits, and the subsequent removal of the Residential Exchange Program credit from residential and small farm customer bills that passes such benefits to customers, has resulted in an approximate 14% average rate increase for those customers. PGE is participating with other IOUs to pursue available options - judicial, regulatory, and legislative - to restore their customers' federal power benefits.

Power Supply - PGE utilizes its own generating resources, along with wholesale market purchases, to meet the energy needs of its customers. The Company has adopted a power cost strategy that extends the terms for which it will enter into purchases and sales of power and fuel. It is expected that this strategy will reduce price volatility for retail customers. The Company's generating facilities performed well in the first half of 2007, as plants operated reliably and cost effectively.

Regional hydro conditions, as measured on the Columbia River at The Dalles, Oregon, are forecast to be below normal for 2007. Stream flows at mid-Columbia hydro projects, with which PGE has long-term power purchase contracts, have been above average and are forecast to be near normal in 2007. Reduced runoff on both the Clackamas and Deschutes rivers, however, has resulted in lower generation from PGE's hydro facilities, with current forecasts projecting continued below normal stream flows for the remainder of 2007.

With the new Port Westward Generating Plant (Port Westward) placed in service in June 2007, PGE continues to deliver on its commitment to add cost-effective resources that supplement the output of existing facilities and reduce dependence on the wholesale energy market.

Construction of Phase I of the Biglow Canyon Wind Farm, which will have an installed capacity of 125 MW, has begun and is expected to be completed by the end of 2007. In June 2007, a stipulation was filed with the OPUC that modified a requested annual revenue requirement increase filed by PGE in March 2007. If approved, new rates are expected to become effective January 1, 2008. Phases II and III are currently in the planning stages. For further information, see "Biglow Canyon Wind Farm" in "Financial and Operating Outlook" of this Item 2.

PGE's plan to meet customers' future electricity needs, as outlined in a new IRP filed with the OPUC on June 29, 2007, includes a diversified portfolio of supply-side and demand-side resources designed to balance cost, price stability, and overall risk. For further information, see "Integrated Resource Plan" in "Financial and Operating Outlook" of this Item 2.

Regulatory Matters - In January 2007, the OPUC issued an order in PGE's general rate case that included new retail rates related to both general and power costs. The order also approved a 2.8% increase for recovery of Port Westward, which became effective on June 15, 2007. Under a process outlined in the order, an intervenor has challenged the Port Westward rate increase, which may result in the incremental revenues being subject to refund. The OPUC staff has indicated its support of the new rates. For further information, see "Port Westward Generating Plant" in "Financial and Operating Outlook" of this Item 2.

In April 2007, PGE submitted to the OPUC its initial filing under the new Annual Power Cost Update Tariff. The filing contained a preliminary forecast of 2008NVPC, which was updated on July 11, 2007. This update projects an approximate 2% overall increase in customer rates. The final forecast of 2008 power costs, and the related change in customer rates, will be submitted in the fourth quarter of 2007. For further information, see "Power Cost Adjustment Mechanism" and "General Rate Case" in "Financial and Operating Outlook" of this Item 2.

PGE is working through the regulatory process to install a system-wide advanced metering infrastructure (AMI) network. The AMI project is expected to provide improved services to customers, achieve operational efficiencies and cost reductions, and serve as a platform for demand side management programs as they become cost effective. PGE filed a tariff with the OPUC, updated in July 2007, for approval to move this project forward. If approved, the Company expects full deployment by the end of 2010. For further information, see "Advanced Metering Infrastructure" in "Financial and Operating Outlook" of this Item 2.

Regional haze and mercury issues may require that PGE make modifications to its thermal generating facilities. The Environmental Protection Agency (EPA) has authority under the Clean Air Act to regulate greenhouse gases (including carbon dioxide), and both Oregon and Montana have tightened controls on mercury emissions, which could have an impact on both the Boardman and Colstrip plants. Although the full impact of future remediation measures is not yet determinable, it is expected that they will result in increased expenditures and be reflected in the Company's revenue requirements.

The Energy Policy Act of 2005 provided the Federal Energy Regulatory Commission (FERC) broad authority to review, approve and enforce national and regional electric reliability standards. Such standards, the majority of which apply to PGE, became effective on June 18, 2007. PGE has submitted mitigation plans to the Western Electricity Coordinating Council related to those standards with which the Company was not yet in compliance.

Pursuant to FERC Order 890, which became effective on July 14, 2007, PGE made a compliance filing to incorporate into its Open Access Transmission Tariff (OATT) the non-rate terms and conditions contained in the order. PGE will submit additional compliance filings to incorporate other new OATT provisions.

Financial Performance - Operating results for the first half of 2007 were markedly improved from the first half of last year due to improved margins on higher retail energy deliveries. Results for the first half of 2006 were adversely affected by the approximate $52 million incremental cost of replacing the output of Boardman, which was out of service for repairs. Results for the first half of 2007 include the positive impacts of a $20 million deferral of Boardman replacement power costs for future rate recovery, as approved by the OPUC. The settlement between PGE and certain California parties related to wholesale energy transactions in the western markets during 2000-2001 resulted in a $6 million increase to pre-tax income and an approximate $28 million cash settlement, which was received in June 2007.

On May 2, 2007, PGE's Board of Directors declared a quarterly common stock dividend of 23.5 cents per share, a 4.4% increase over the previous quarterly dividend.

PGE issued $170 million of First Mortgage Bonds in May 2007 under an agreement reached late last year and plans to issue $130 million of First Mortgage Bonds by October 1, 2007 under an April 2007 agreement. The Company maintains its investment grade bond ratings and stable operating cash flow, with adequate liquidity available through both its $400 million credit facility (which was extended for an additional year) and access to the commercial paper market. Such sources, along with the Company's ability to issue long-term debt and equity securities, are expected to sufficiently provide for continued capital and operating requirements, including investment in renewable energy from the Biglow Canyon project and the proposed AMI project.

Results of Operations

The following review of PGE's results of operations should be read in conjunction with the condensed consolidated financial statements and related notes included elsewhere in this report. Due to seasonal fluctuations in electricity sales, as well as the price of wholesale energy and natural gas costs, quarterly operating earnings are not necessarily indicative of results to be expected for calendar year 2007.

2007 Compared to 2006 for the Three Months Ended June 30

PGE's net income in the second quarter of 2007 was $46 million, or $0.73 per diluted share, compared to $27 million, or $0.43 per diluted share, in the second quarter of 2006. The improved results were primarily attributable to increased margins on energy sales, as power costs in the second quarter of 2007 reflect the return of Boardman to full operation. Also contributing to the increase in earnings was the approximate $8 million after tax impact of adjustments related to SB 408, with a potential collection from customers recorded in the second quarter of 2007 and a potential customer refund recorded in the second quarter of 2006.

The following table summarizes Operating Revenues and Energy Sold and Delivered for the second quarter of 2007 and 2006:

	Three Months Ended June 30,		
	2007	**2006**	**Increase/ (Decrease)**
Operating revenues (millions)			
Retail sales			
Residential	$ 149	$ 132	$ 17
Commercial	144	134	10
Industrial	41	52	(11)
Total retail sales	334	318	16
Direct access customers			
Commercial	-	(2)	2
Industrial	(3)	(1)	(2)
Tariff revenues	331	315	16
Regional Power Act credits	16	6	10
Provision for collection (refund) - SB 408	4	(9)	13
Accrued revenues	(1)	2	(3)
Total retail revenues	350	314	36
Wholesale revenues	44	30	14
Other operating revenues	8	7	1
Total Operating Revenues	$ 402	$ 351	$ 51

	Three Months Ended June 30, 2007	2006	Increase/ (Decrease)
Energy sold and delivered - MWhs (thousands)			
Retail energy sales			
Residential	1,633	1,607	26
Commercial	1,786	1,783	3
Industrial	665	922	(257)
Total retail energy sales	4,084	4,312	(228)
Delivery to direct access customers			
Commercial	129	120	9
Industrial	410	143	267
Total retail energy deliveries	4,623	4,575	48
Wholesale sales	916	897	19
Total energy sold and delivered	5,539	5,472	67
Customers - end of period			
Residential	701,697	691,830	9,867
Commercial	100,051	98,709	1,342
Industrial	259	256	3
Total retail customers	802,007	790,795	11,212

Total Operating Revenues in the second quarter of 2007 increased 14.5% from last year's second quarter, with an 11.5% increase in Total Retail Revenues and higher Wholesale Revenues. The increase in Retail Revenues resulted from 2007 rate increases and higher energy deliveries, as well as the conversion of Regional Power Act (RPA) benefits to all cash from a combination of cash and below-market power purchases. RPA benefits were suspended in the second quarter of 2007 (see "Residential Exchange Program" in the "Financial and Operating Outlook" of this Item 2 for further information). Revenue reductions for direct access customers were 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. PGE recorded a $4 million potential collection from customers in the second quarter of 2007, compared to a potential refund of $9 million in last year's second quarter, related to the Company's current estimates of the impact of SB 408. See "General Rate Case" and "Utility Rate Treatment of Income Taxes" in the "Financial and Operating Outlook" of this Item 2 for further information.

A 1% increase in total retail energy deliveries resulted primarily from an approximate 11,600 increase in the average number of customers served over the second quarter of 2006. Energy sales to residential customers increased 1.6% and total energy deliveries to commercial customers increased 0.6% during the second quarter of 2007. Lower sales to industrial customers resulted from an increase in direct access customers that now purchase their energy requirements from Energy Service Suppliers (ESSs).

Wholesale revenues increased 47% from last year's second quarter due primarily to an increase in wholesale energy prices, caused by higher prices for natural gas and decreased regional hydro availability.

Purchased Power and Fuel expenses in the second quarter of 2007 increased $32 million, or 22%, from last year's second quarter. The increase was due primarily to a higher average cost of purchased power, driven by an increase in natural gas prices and a reduction in regional hydro availability. Such increases were partially offset by a 4% reduction in total system load and the availability of Boardman.

Company-owned generation increased 57% from last year's second quarter. The return of Boardman to full operation, combined with increased combustion turbine generation (including that from PGE's new Port Westward plant), resulted in a 158% increase in thermal generation and the economic displacement of higher cost purchases in the wholesale market. Partially offsetting the increase in thermal generation was a 24% decrease in hydro production due to lower stream flows in the second quarter of 2007. Company-owned generation met approximately 37% of PGE's retail load during this year's second quarter compared to 22% in the second quarter of 2006. PGE has long-term agreements to purchase power generated at hydro facilities on the mid-Columbia River in the state of Washington. Energy received under these agreements increased 4% in the second quarter of 2007 from the second quarter of 2006.

The following table indicates PGE's total system load (including both retail and wholesale) for the second quarters of 2007 and 2006. Average variable power costs include wheeling and exclude unrealized gains and losses from derivative instruments.

Megawatt/Variable Power Costs

	Megawatt-Hours (thousands)		Average Variable Power Cost (Mills/kWh)	
	2007	2006	2007	2006
Generation	1,601	1,018	19.7	8.9
Term Purchases	3,592	3,921	35.5	26.3
Spot Purchases	61	548	*	20.1
Total System Load	5,254	5,487	32.7	25.4

* Based on the relatively small amount of spot purchases that were physically delivered in the quarter and the result of net basis reporting, as required by EITF 03-11, the average variable power cost was not meaningful for the quarter.

PGE's average variable power cost increased 29% from last year's second quarter due primarily to the higher average cost of term purchases. The higher average cost of generation in this year's second quarter resulted from an increase in the average cost of gas-fired production, including the effect of lower margins on settled natural gas hedging transactions.

Production and distribution expenses increased $8 million from last year's second quarter due primarily to higher repair and maintenance costs at Boardman and an increase in distribution expenses, primarily related to overhead line maintenance. Planned activities at Boardman, which were performed during the first quarter of 2006 during the plant's forced outage, were completed during a planned outage in the second quarter of 2007.

Depreciation and amortization expenses decreased $10 million from the second quarter of 2006. An approximate $6 million decrease was attributable to reductions in both depreciation rates for utility plant and in the authorized recovery of Trojan decommissioning costs, both of which became effective in January 2007 pursuant to the OPUC order in PGE's general rate case. In addition, there was a $3 million decrease in the amortization of regulatory assets (fully offset within Net Operating Income due to a corresponding decrease in Operating Revenues).

Income taxes increased $5 million due primarily to higher taxable income in the second quarter of 2007.

Other Income increased $6 million primarily due to an increase in income from non-qualified benefit plan trust assets and accrued interest on $26.4 million of excess power costs associated with Boardman's repair outage, which has been deferred for future rate recovery as approved by the OPUC.

2007 Compared to 2006 for the Six Months Ended June 30

PGE's net income was $101 million, or $1.61 per diluted share, in the first half of 2007 compared to $21 million, or $0.34 per diluted share, in the first half of 2006. The increase was attributable to improved margins on energy sales, as power costs in the first half of 2006 were adversely affected by the repair outage at Boardman and by unrealized losses on power and natural gas contracts. Results for the first half of 2007 include the positive impacts of the deferral of a portion of Boardman replacement power costs for future rate recovery (as approved by the OPUC) and the settlement between PGE and certain California parties related to wholesale energy transactions in the western energy markets during 2000-2001. Also contributing to the increase in earnings was an approximate $8 million after tax impact of adjustments related to SB 408, with a potential collection from customers recorded in the first half of 2007 and a potential customer refund recorded in the first half of 2006.

The following table summarizes Operating Revenues and Energy Sold and Delivered for the first half of 2007 and 2006:

	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006	Increase/ (Decrease)
Operating revenues (millions)			
Retail sales			
Residential	$ 341	$ 313	$ 28
Commercial	283	263	20
Industrial	78	100	(22)
Total retail sales	702	676	26
Direct access customers			
Commercial	-	(3)	3
Industrial	(6)	(3)	(3)
Tariff revenues	696	670	26
Regional Power Act credits	42	6	36
Provision for collection (refund) - SB 408	5	(9)	14
Accrued revenues	-	1	(1)
Total retail revenues	743	668	75
Wholesale revenues	81	54	27
Other operating revenues	14	10	4
Total Operating Revenues	$ 838	$ 732	$ 106

	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006	Increase/ (Decrease)
Energy sold and delivered - MWhs (thousands)			
Retail energy sales			
Residential	3,903	3,819	84
Commercial	3,532	3,520	12
Industrial	1,243	1,746	(503)
Total retail energy sales	8,678	9,085	(407)
Delivery to direct access customers			
Commercial	241	220	21
Industrial	804	290	514
Total retail energy deliveries	9,723	9,595	128
Wholesale sales	1,939	1,509	430
Total energy sold and delivered	11,662	11,104	558

Total Operating Revenues in the first half of 2007 increased 14.5% from last year's first half, with an 11.2% increase in Total Retail Revenues accompanied by higher Wholesale and Other Operating Revenues. The increase in Retail Revenues resulted from 2007 rate increases and higher energy deliveries, as well as the conversion of Regional Power Act (RPA) benefits to all cash from a combination of cash and below-market power purchases. RPA benefits were suspended in the second quarter of 2007. (See "General Rate Case" and "Residential Exchange Program" in the "Financial and Operating Outlook" of this Item 2 for further information). Revenue reductions for direct access customers were 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.

A 1.3% increase in total retail energy deliveries resulted primarily from an approximate 11,900 increase in the average number of customers served in the first half of 2007. Energy sales to residential customers increased 2.2% and total energy deliveries to commercial customers increased 0.9% during the first half of 2007. Lower sales to industrial customers resulted from an increase in direct access customers that now purchase their energy requirements from ESSs.

Wholesale revenues increased 50% from last year's first half due to both a 28% increase in energy sales and an 18% increase in the average sales price, resulting from higher natural gas prices and lower regional hydro availability.

The increase in Other Operating Revenues from last year's first half was primarily the result of increased gains from the sale of natural gas in excess of generating plant requirements.

Purchased Power and Fuel expenses in the first half of 2007 approximated that of last year's first half. An increase in the average cost of purchased power was partially offset by reduced electricity purchases, related to the return of Boardman to full operation. In addition, unrealized losses on derivative activities reflected in expense in 2006 are deferred in 2007 to reflect the approval of a power cost adjustment mechanism by the OPUC (see "Price Risk Management" in the "Financial and Operating Outlook" of this Item 2 for further information). Results for the first half of 2007 reflect the deferral, for future rate recovery, of $20.4 million of excess Boardman power costs (approved by the OPUC in February 2007), and a $6 million reduction in the Company's wholesale credit reserve related to the settlement with certain California parties involving wholesale energy transactions in 2000-2001. See "Boardman Coal Plant - Repair Outages" and "Receivables and Refunds on Wholesale Market Transactions" in the "Financial and Operating Outlook" of this Item 2 for further information.

Company-owned generation increased 59% from the first half of 2006. The return of Boardman to full operation, combined with increased combustion turbine generation, resulted in a 132% increase in thermal production and the economic displacement of higher cost purchases in the wholesale market. Partially offsetting the increase in thermal production was a 15% decrease in hydro production, resulting from lower stream flows. Company-owned generation met approximately 42% of PGE's retail load during the first half of 2007 compared to 25% in the first half of 2006. PGE has long term agreements to purchase power generated from hydro facilities on the mid-Columbia River. Energy received under these agreements increased 6% in the first half of 2007 from the first half of 2006.

The following table indicates PGE's total system load (including both retail and wholesale) for the first half of 2007 and 2006. Average variable power costs include wheeling and exclude unrealized gains and losses from derivative instruments.

Megawatt/Variable Power Costs

	Megawatt-Hours (thousands)		Average Variable Power Cost (Mills/kWh)	
	2007	2006	2007	2006
Generation	3,911	2,452	17.1	5.4
Term Purchases	6,725	7,746	42.9	35.5
Spot Purchases	616	1,074	20.8	26.9
Total System Load	11,252	11,272	35.6	31.0

PGE's average variable power cost increased 15% from last year's first half due primarily to the higher cost of term purchases, higher gas prices, and a lower proportion of hydro generation to total generation. The lower average cost of generation in the first half of 2006 was partly the result of higher margins on settled natural gas hedging transactions.

Production, distribution, administrative and other expenses increased $15 million from last year's first half, due primarily to higher employee benefit expenses. In addition, higher customer support and distribution expenses (related to tree trimming and overhead line maintenance), as well as increased maintenance activities at Boardman and Colstrip, contributed to the increase in the first half of 2007.

Depreciation and amortization expenses decreased $22 million from the first half of 2006. An approximate $12 million decrease was attributable to reductions in both depreciation rates for utility plant and in the authorized recovery of Trojan decommissioning costs, both of which became effective in January 2007 pursuant to the OPUC order in PGE's general rate case. In addition, there was a $6 million decrease in the amortization of regulatory assets (fully offset within Net Operating Income due to a corresponding decrease in Operating Revenues) and a $4 million reduction in other amortization related to the deferral of certain tax credits.

Income taxes increased $35 million due primarily to higher taxable income in the first half of 2007.

Other Income increased $10 million in the first half of 2007. Included in the increase was a $4 million interest accrual (retroactive to January 2006) on $26.4 million of excess power costs associated with Boardman's repair outage, which has been deferred for future rate recovery, as approved by the OPUC. A $3 million increase in income from non-qualified benefit plan trust assets and a $2 million increase in the allowance for equity funds used during construction, related primarily to PGE's new Port Westward plant, also contributed to the increase in the first half of 2007.

Capital Resources and Liquidity

Review of Statements of Cash Flows

Cash Provided by Operations is used to meet the day-to-day cash requirements of PGE. 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 $201 million in the first half of 2007 compared to $46 million in the same period last year. The increase was due primarily to a reduction in margin deposit requirements with certain wholesale customers, which contributed $82 million more cash flow in the first half of 2007, as well as a $65 million reduction in power purchases from the same period last year, when the Company was required to replace the output of the Boardman coal plant.

Investing Activities consist of new construction and improvements to PGE's distribution, transmission, and generation facilities. The $52 million decrease in capital expenditures in the first half of 2007 compared to the same period last year was primarily due to a $77 million decrease in construction costs for Port Westward in 2007, partially offset by a $26 million increase in expenditures in 2007 for the Biglow Canyon wind project. 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.

On May 16, 2007, PGE received $170 million from the sale of First Mortgage Bonds to certain institutional buyers in the private placement market, pursuant to an agreement entered into in December 2006. The bonds were issued under PGE's Indenture of Mortgage and Deed of Trust, dated July 1, 1945, as amended and supplemented to date and from time to time (including the Fifty-seventh Supplemental Indenture dated December 1, 2006). The bonds bear interest at an annual rate of 5.80% and will mature on June 1, 2039. The proceeds from the sale of the bonds will be used for general corporate purposes, which may include capital expenditures and/or the repayment of existing debt.

On June 15, 2007, PGE redeemed $50 million of 7.15% First Mortgage Bonds at maturity and the remaining $16 million of 7.75% Series Cumulative Preferred Stock, which was mandatory. On June 27, 2007, the Company elected to redeem, at par value, $5.1 million of 7 1/8% Port of St. Helens Pollution Control Bonds due in 2014.

PGE reduced short term debt by $81 million and paid $28 million of common stock dividends during the first half of 2007. In March 2007, PGE remarketed $5.8 million of variable interest rate Port of Morrow Pollution Control Bonds due in 2031 under a new remarketing agreement.

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 June 30, 2007, PGE had utilized approximately $13 million in letters of credit ($4 million related to wholesale trading activities, $4 million related to Port Westward, and $5 million related to Biglow Canyon Wind Farm), with approximately $387 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 June 2007, upon approval of all participating banks, the termination date of the facility was extended to July 13, 2012. 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 June 30, 2007, the Company's consolidated indebtedness to total capitalization ratio, as calculated under the facility, was 46.1%.

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.

The issuance of additional First Mortgage Bonds requires that PGE 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 June 30, 2007 it could issue up to approximately $474 million of First Mortgage Bonds under the most restrictive issuance test in the mortgage. 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.

On April 12, 2007, PGE and certain institutional buyers in the private placement market entered into a bond purchase agreement under which PGE agreed to sell $130 million of PGE's First Mortgage Bonds to the buyers. Funding will take place, and the bonds transferred to the buyers, at the direction of PGE at any time up to, but not later than, October 1, 2007 (subject to five business days notification).

On June 4, 2007, PGE filed a shelf registration statement with the Securities and Exchange Commission (SEC) for the purpose of issuing common stock and first mortgage bonds from time to time as determined in light of market conditions and other factors, the proceeds from which will be used to fund planned capital and other expenditures.

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.

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 a 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 53.9% and 53.0% at June 30, 2007 and December 31, 2006, 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 $200 million annually over the period 2007-2009. Combined with all other sources, cash provided by operations is estimated to range from $320 million to $360 million annually during the 2007-2009 period.

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

	2007	2008	2009
Capital expenditures (*)	$525 - $535	$310 - $330	$650 - $670
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 $16 million for 2007), fish passage measures at the Pelton Round Butte hydroelectric project (approximately $52 million for 2007 - 2009), and anticipated expenditures for Phases II and III of the Biglow Canyon Wind Farm (approximately $480 million to $490 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, equity securities, or a combination of the two, in the future. The structure, timing and amount of such financings depend on market conditions and financing needs. On July 17, 2007, PGE filed an application with the OPUC to issue an additional $75 million of First Mortgage Bonds to fund capital expenditures and acquisition of utility property, among other requirements.

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).

Dividends on Common Stock - The following table indicates common stock dividends declared in 2007:

Declaration Date	Record Date	Payment Date	Dividends Declared per Common Share
February 22, 2007	March 26, 2007	April 16, 2007	$0.225
May 2, 2007	June 25, 2007	July 16, 2007	$0.235
August 2, 2007	September 25, 2007	October 15, 2007	$0.235

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 the OPUC approve the payment of dividends that reduce the Company's common equity capital percentage below certain levels, depending upon the percentage of issued and outstanding common stock held by the DCR. As the DCR sold substantially all of its PGE common stock in June 2007, this requirement is no longer applicable.

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	S&P
First Mortgage Bonds	Baa1	BBB+
Senior unsecured debt	Baa2	BBB
Commercial paper	Prime-2	A-2
Outlook:	Stable	Negative

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 June 30, 2007, PGE had posted approximately $16 million of collateral, consisting of $4 million in letters of credit and $12 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 June 30, 2007, the approximate amount of additional collateral that could be requested upon a single agency downgrade event to below investment grade is approximately $45 million and decreases to approximately $9 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 $71 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.

Contractual Obligations and Commercial Commitments

PGE's contractual obligations outside the ordinary course of business have not changed materially from those disclosed in the Company's Annual Report on Form 10-K for the year ended December 31, 2006.

Critical Accounting Policies and Estimates

PGE's critical accounting policies that require the use of estimates and assumptions are discussed further in the Company's Annual Report on Form 10-K for the year ended December 31, 2006.

Financial and Operating Outlook

Retail Customer Growth and Energy Deliveries

Weather adjusted retail energy deliveries to PGE and ESS customers increased 1.2% for the six months ended June 30, 2007, compared to the same period last year. The increase was due primarily to 1.3% and 1.6% increases, respectively, in residential and commercial deliveries. Increased residential sales resulted primarily from a 10,300 increase in the average number of customers served during the first six months of 2007 over the first six months of 2006. Higher commercial and industrial sales resulted from a 1,600 increase in the average number of customers served and higher average usage. PGE forecasts annual weather adjusted energy deliveries to PGE and ESS customers in 2007 to increase by approximately 1.3% from last year.

Power and Fuel Supply

Current forecasts indicate that regional hydro conditions for the full year 2007 will be somewhat below normal levels. Volumetric water supply forecasts for the Pacific Northwest region, prepared by the Northwest River Forecast Center in conjunction with the Natural Resources Conservation Service and other cooperating agencies, indicate the April-to-September runoff on the Columbia River (as measured at The Dalles, Oregon) at 86% of normal, compared to actual runoff of 107% of normal in 2006. The mid-Columbia (as measured at Grand Coulee, Washington) is forecast at 99% of normal, compared to actual runoff of approximately 101% in 2006. Hydro conditions on the Clackamas and Deschutes river systems, where PGE's hydro facilities are located, are currently projected to be 68% and 89% of normal, respectively, compared to actual runoffs of approximately 92% and 100% of normal, respectively, in 2006.

PGE generated 42% of its retail load requirement in the first six months of 2007, with 31% 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. The addition of Port Westward in June 2007 has further enhanced the Company's ability to meet its retail load requirements.

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 continue to show long-term upward trends in the forward markets, with occasional short-term periods of price rollbacks. If longer term prices for natural gas increase, it would affect the cost of natural gas required to fuel PGE's combustion turbine generating plants as well as prices of power purchased in the wholesale market.

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 (Accounting for Derivative Instruments and Hedging Activities), 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 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 Resource Valuation Mechanism (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, Accounting for the Effects of Certain Types of Regulation.

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 NVPC 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 normally takes 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.

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. The shares of PGE common stock previously held by Enron were cancelled. Approximately 27 million shares of the new PGE common stock were initially issued to the Debtors' creditors who held allowed claims, and approximately 35.5 million shares were issued to a Disputed Claims Reserve (DCR), where the shares were held to be released over time to the Debtors' creditors who held allowed claims, in accordance with the Chapter 11 Plan.

On June 18, 2007, the DCR sold 23.7 million shares of PGE common stock pursuant to a secondary offering. With the completion of this offering, all of PGE's common stock is now publicly traded.

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 still exist with respect to the 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. A portion of the tax credits was utilized to offset quarterly income tax payments due to the State of Oregon during 2006 and 2007 with no effect on income. Any realization of these tax credits will be reflected as an adjustment to equity.

General Rate Case

On January 12, 2007, the OPUC issued an order approving an overall price increase of approximately 1.3%, which was allocated to all PGE customer classes. The increase represents the combined effect of a 2.8% increase related to cost recovery of Port Westward, which became effective when the plant went into service in June 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 was on or after May 2, 2007. See "Port Westward Generating Plant" in this Item 2 for further information.

Power Cost Adjustment Mechanism

Effective January 17, 2007, 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 NVPC included in rates (the baseline), and actual NVPC on a settlement basis. Under the PCAM, PGE will be subject to a portion of the business risk or benefit associated with actual NVPC varying from costs included in base rates by: (1) applying an asymmetrical deadband for PGE to absorb cost increases or decreases, with a 90/10 sharing of costs and benefits between customers and the Company, respectively, beyond the deadband, and (2) employing a regulated earnings test.

The asymmetrical deadband is based on 75 basis points below and 150 basis points above PGE's authorized return on equity (ROE), or approximately $(11.7) million and $23.4 million, respectively, for 2007. The Annual Variance is defined as the difference between actual NVPC and baseline NVPC. An Annual Power Cost Variance (PCV), defined as 90% of the Annual Variance outside the deadband, is recorded as a customer refund or collection (subject to a regulated earnings test). The following table summarizes the approximate PCAM deadband for 2007 (in millions):

Annual Variance Amount	PCV Deferral for Refund or Collection
If more than $(11.7) below baseline - refund	90% of Annual Variance in excess of $(11.7)
Between $(11.7) and $23.4	No deferral
If more than $23.4 above baseline - collection	90% of Annual Variance in excess of $23.4

The refund or collection amount will be subject to a regulated earnings test for the year that the NVPC were incurred. The customer refund amount will be limited to the extent that such refund will not cause PGE's actual regulated ROE for the year to fall below its authorized ROE plus 100 basis points, or 11.1%. Conversely, the customer collection amount will be limited to the extent that such collection will not cause PGE's actual regulated ROE for the year to exceed its authorized ROE minus 100 basis points, or 9.1%. A regulatory asset or liability will be recorded, with the offset to Purchased Power and Fuel expense, for any PCV deferral that arises. Interest will accrue on any deferral at the Company's authorized rate of return.

As of June 30, 2007, the year-to-date Annual Variance is $14.8 million below the baseline. Since this variance amount exceeded the $(11.7) million deadband, a $2.8 million regulatory liability was recorded for the second quarter of 2007. Any regulatory asset or liability arising from the deadband calculation would be adjusted by a regulated earnings test calculation at year end. Final determination of any refund or collection amount would be determined by the OPUC through a public filing and review.

Annually, the Company will propose PCV adjustment rates that will amortize the PCV to customer rates. The OPUC will make the final determination regarding such rates and the period over which they would apply.

In addition, as part of its Order No. 07-015, issued on January 12, 2007, the OPUC adopted an Annual Power Cost Update Tariff, which replaces the RVM. The Annual Power Cost Update Tariff provides for rate adjustments to reflect updated forecasts of NVPC for future calendar years. The approved Annual Power Cost Update Tariff establishes the new baseline NVPC for purposes of the PCAM calculation each year. On July 11, 2007, PGE submitted to the OPUC an update of its 2008 NVPC forecast. The Company projects an approximate 2% average increase in customer rates, effective January 1, 2008. A final 2008 NVPC forecast will be submitted to the OPUC in the fourth quarter of 2007.

Residential Exchange Program

The Residential Exchange Program, administered by the Bonneville Power Administration (BPA), was created to provide benefits of federal power to residential and small farm customers of the region's investor-owned utilities (IOUs). In October 2000, PGE and other IOUs entered into settlement agreements with BPA related to the exchange program covering the period October 1, 2001 through September 30, 2011. In 2006, PGE customers received approximately $111 million in benefits under the exchange program.

On May 3, 2007, the U.S. Ninth Circuit Court of Appeals issued two decisions with respect to the settlement agreements. One decision found that the agreements were inconsistent with the Northwest Power Act, which created the Residential Exchange Program. The other decision holds, among other things, that the BPA acted contrary to law when it allocated to its preference customers, which include public utilities, cooperatives and federal agencies, part of the costs of the October 2000 settlements.

Based upon the Court of Appeal's decisions, the BPA on May 21, 2007 notified PGE and six other IOUs that it was immediately suspending the Residential Exchange Program payments that the IOUs pass through to their residential and small farm customers in the form of monthly billing credits. In its notice, the BPA indicated that the suspension will continue at least until any petitions for rehearing on the decisions are finally resolved.

Pursuant to the Company's request, the OPUC approved the removal of the Residential Exchange Program credit from PGE customers' bills, effective June 1, 2007, resulting in an approximate 14% average rate increase for customers. Total customer credits for 2007 had been estimated at $95 million, of which PGE customers had received $47 million prior to the suspension. As of June 30, 2007, benefits provided by PGE to customers exceeded payments received from BPA by $9 million. Such amount, included as a regulatory asset on the Condensed Consolidated Balance Sheet, will accrue interest pending disposition of this matter.

PGE is participating with other IOUs to pursue available options - judicial, regulatory, and legislative - to restore their customers' federal power benefits. On July 18, 2007, PGE and other IOUs jointly filed a petition requesting a rehearing before the full Court of Appeals. The OPUC and the Washington Utility Transportation Commission also filed such a petition. Because these benefits are passed through to PGE's customers, the outcome of this matter is not expected to have a significant effect on the Company's consolidated financial results.

Advanced Metering Infrastructure

On March 7, 2007, PGE filed a tariff with the OPUC seeking an increase of approximately $13 million in annual revenue requirements related to the installation of over 800,000 new advanced meters. The AMI network would facilitate daily, two way communications between PGE and customer meters, and is expected to provide improved services while achieving operational efficiencies and cost reductions.

On July 27, 2007, PGE filed testimony requesting that the tariff effective date be moved from January 1, 2008, to June 1, 2008, and run through December 31, 2010. This decision was based on the meter technology vendor requiring additional time to complete its scalability testing and deliver host-system software. In addition, the Company seeks to minimize the initial rate impact of AMI by timing the project's implementation to coincide with potential customer rate credits expected from SB 408. The proposed tariff would run for approximately two and a half years, coinciding with the period over which PGE completes systems acceptance testing and installation of the meters. After the tariff period ends, the project's costs, net of savings, will be incorporated into a future general rate case. Once the meters are installed, at an estimated capital cost of $132 million, the Company estimates that the AMI network will save approximately $18 million annually in operating expenses, providing future benefits to customers.

Renewable Energy Standard

The 2007 Oregon legislature passed a new Renewable Energy Standard which requires that large electricity providers such as PGE serve at least 25% of their retail load from renewable resources by the year 2025. The standard provides for a graduated approach, with an initial requirement of 5% by 2011, increasing to 15% by 2015 and to 20% by 2020. The Company currently serves approximately 4% of its retail load from renewable sources and forecasts that it will serve approximately 10% of its retail load from such sources by 2011, assuming completion of Phases II and III of Biglow Canyon.

Integrated Resource Plan

PGE filed a new Integrated Resource Plan (IRP) with the OPUC on June 29, 2007. The IRP describes the Company's energy supply strategy for the years 2008 through 2015 and includes additional renewable resources, energy efficiency, demand-side resources, power purchase agreements of varying terms, and the acquisition of additional peaking capacity. The plan was developed over an 18-month period that included significant research and discussion with customer groups, independent consultants, and regulators. The planning process was designed to identify the best combination of least cost and least risk energy resources available while considering the environmental impacts, the dispatch capabilities of various resources, transmission access, fuel supply availability and price volatility.

The IRP action plan proposes the following:

- Continued development of the Biglow Canyon wind project in Sherman County, Oregon, with wind turbines to provide a total maximum generating capacity of between 400 and 450 MW. Phase I is under construction with Phases II and III expected to be completed by 2010.
- Procurement of an additional 218 average megawatts of renewable power. Combined with Biglow Canyon and existing renewable resources, this will help PGE meet Oregon's new Renewable Energy Standard, which requires that electricity providers serve at least 15% of their load with renewable energy by 2015 and 25% by 2025.
- Expansion of energy efficiency programs in partnership with the Energy Trust of Oregon. The goal is to increase the amount of load met through efficiency measures by an additional 45 MW (beyond the amount already targeted by the Energy Trust) by 2012.
- Purchase power agreements with durations of five to ten years, intended to reduce reliance on energy markets, help stabilize customer prices, and meet electricity demand while giving new technologies time to mature and become cost-effective.
- Acquisition of 100 MW of peaking capacity, through ownership or contract, to meet an increase in forecasted winter and summer peak requirements and to facilitate the integration of variable wind generation.

Review of the IRP by stakeholders and the OPUC staff is expected to take place over an approximate six-month period. The review process is completed when the OPUC determines that the action plan appears reasonable and issues an order acknowledging it.

Utility Rate Treatment of Income Taxes

An Oregon 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 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.

The OPUC has adopted rules to implement SB 408. The rules include the use of fixed reference points for margins and effective tax rates from a ratemaking proceeding. The rules also include 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 its 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 its 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. The Oregon legislature did not address this issue in the 2007 legislative session and it is uncertain whether it will be considered in the future. Accordingly, the ultimate outcome of this matter is not certain.

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 OPUC 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.

PGE has estimated its potential refunds to customers to be approximately $42 million (including $2 million of accrued interest) for 2006 and recorded a (pre-tax) reserve of such amount for the year. (The reserve includes $17 million paid to Enron for net current taxes payable for the first quarter of 2006 when PGE was included in its former parent's consolidated group for filing consolidated federal and state income tax returns). Interest will continue to accrue on the reserve, with an additional $2 million recorded in the first half of 2007. In accordance with the statute, PGE 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. Under the OPUC rules, any refunds to customers for the 2006 tax year would begin after June 1, 2008.

For the year 2007, PGE estimates a potential collection from customers of approximately $10 million. Based on a percentage of estimated annual revenues collected in the first half of the year, PGE deferred, as a regulatory asset, approximately $5 million (including accrued interest) at June 30, 2007. Any collections from, or refunds to, customers for the 2007 tax year will be reported in the Company's October 15, 2008 filing with the OPUC.

PGE is participating in an OPUC rulemaking process to resolve certain issues related to the application of SB 408 rules. A procedural schedule has been established, with completion of the process expected by September 2007.

Complaint and Application for Deferral - Income Taxes - On October 5, 2005, the Utility Reform Project (URP) and Ken Lewis (together, the 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.

Boardman Coal Plant - Repair Outages

PGE's Boardman coal plant was taken out of service in late October 2005 for repairs and did not return to full operation until July 1, 2006. During the outage, PGE incurred incremental power costs of approximately $92 million, with $40 million and $52 million incurred in 2005 and 2006, respectively.

In November 2005, PGE filed an application with the OPUC to defer for later ratemaking treatment approximately $46 million, representing estimated excess power costs associated with a portion of Boardman's outage. On February 12, 2007, the OPUC issued an order authorizing PGE to defer $26.4 million, based on a sharing mechanism that divides responsibility for the outage costs between PGE's customers and shareholders. (A petition for reconsideration of the OPUC order, filed in April 2007 by Industrial Customers of Northwest Utilities, a regional industrial trade association, was denied by the OPUC in June 2007). PGE recorded a deferral of $6 million at December 31, 2006, with the remaining $20.4 million recorded in the first quarter of 2007. In addition, approximately $3.6 million of accrued interest (retroactive to January 1, 2006) was recorded in the first half of 2007; interest will continue to accrue on the deferred amount pending ratemaking determination.

PGE expects to file, by the end of September 2007, a request with the OPUC to amortize the deferral of Boardman replacement power costs (including accrued interest). In its filing, the Company will propose that the deferral be offset with certain credits due to customers, with no rate impact anticipated. The ratemaking proceeding 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 over the deferral period to exceed a reasonable range.

Port Westward Generating Plant

On June 11, 2007, Port Westward, a 400 MW natural gas-fired generating facility located in Clatskanie, Oregon, was placed into service. Total cost of the new plant through June 30, 2007 was approximately $280 million (including allowance for funds used during construction, or AFDC).

In January 2007, the OPUC issued a rate order approving a 2.8% increase related to the cost recovery of Port Westward, which became effective on June 15, 2007. In the rate order, the OPUC also established a process for re-examining the rate increase if the plant's in service date was on or after May 2, 2007. The OPUC staff and intervenors were permitted, within 15 days of the in service date of the plant, to request a re-examination of the costs of Port Westward reflected in PGE's rates. The Citizens' Utility Board (CUB) has requested a re-examination, while the OPUC staff has indicated its support of the new rates. If the OPUC determines that further proceedings are necessary, the additional revenues collected as a result of the rate increase would be subject to refund, pending the outcome of the proceedings and any required rate adjustment. If there is no determination that further proceedings are necessary, the new rates are expected to remain in effect.

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, which it plans to own and operate, located in Sherman County, Oregon. PGE currently plans to construct the project, to have a total installed capacity of 400 - 450 MW, in three phases by 2010.

The first phase of the project, which will have an installed capacity of 125 MW, is currently under construction and is expected to be completed by the end of 2007. The total cost is estimated between $255 million and $265 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.

PGE filed a rate application with the OPUC on March 2, 2007 seeking an approximate $13 million, or 0.8%, increase in annual revenue requirements for full recovery of costs related to the first phase of the Biglow Canyon project. In a stipulation filed with the OPUC on June 20, 2007, PGE, OPUC Staff, and other parties agreed to certain adjustments that would reduce Biglow's annual revenue requirements to approximately $9.4 million. The annual revenue reduction from PGE's initial filing is related to expected property tax savings, an increase in the plant's estimated depreciable life, an expected increase in federal tax credits, and certain other adjustments. Further updates to the project's revenue requirements will reflect updated forecasts of market electricity prices and, potentially, partial funding by the Energy

Trust of Oregon. It is anticipated that final rates to recover the costs of Biglow Canyon's first phase will be established by mid-November 2007. If approved, new rates are expected to become effective January 1, 2008.

Phases II and III of the project are currently in the planning stages. In the second quarter of 2007, PGE paid $17 million to a vendor towards wind turbines for Phases II and III. The payment is non-refundable if PGE and the vendor do not execute a definitive agreement after good faith efforts to negotiate and execute such agreement within a specified time period. The payment will be returned to PGE if the vendor fails to negotiate the definitive agreement in good faith. The estimated cost of Phases II and III is $600 million to $700 million, including AFDC, with Phase II expected to be completed by the end of 2009 and Phase III expected to be completed by the end of 2010.

Hydro Relicensing

In March 2006, PGE filed with the FERC a settlement agreement related to the license application for the Company's four hydro projects on the Clackamas River. In December 2006, the FERC issued a Final Environmental Impact Statement that recommended PGE's proposed action with minor modifications. It is not certain when the FERC will issue a new license for the projects. Until a new license is approved, the plants will operate under annual licenses issued by the FERC.

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 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 Oregon 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 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. The 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. 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.

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.

In Order No. 07-157 (the Order) entered on April 19, 2007, the OPUC denied the motion PGE filed in November 2006 to consolidate phases and re-open the record. In addition, the Order abated the Phase I proceeding pending a decision by the Oregon Court of Appeals of the 2003 Remand, and ordered that a second phase of the joint remand proceedings be immediately commenced to investigate the OPUC's delegated authority to engage in retroactive ratemaking. The Order further stated that parties not now participating in the joint remand proceedings will be allowed to intervene and participate in the second phase. The parties have submitted final briefs and oral argument is scheduled for August 9, 2007.

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.

Receivables and Refunds on Wholesale Market Transactions

On May 17, 2007, the FERC approved a March 12, 2007 settlement (the May 17 Settlement) among PGE, the California Attorney General, the California Department of Water Resources, the California Electricity Oversight Board, the California Public Utilities Commission, Southern California Edison Company, Pacific Gas & Electric Company, and San Diego Gas & Electric Company that resolved all issues between the parties relating to wholesale energy transactions in the western markets during the January 1, 2000 through June 20, 2001 time period. The settlement resolved a number of proceedings and investigations before the FERC and the U.S. Ninth Circuit Court of Appeals relating to various issues and claims in the California refund case (Docket No. EL00-95), the issue of refunds for the summer 2000 period, investigations of anomalous bidding activities and market practices (Docket Nos. IN03-10-000 and EL03-165-000), claims for refunds related to sales in the Pacific Northwest (Docket No. EL01-10), and the complaint by the California Attorney General for refunds from market-based rates retroactively to May 1, 2000.

Certain other market participants have now joined the May 17 Settlement, but releases as to those parties do not cover transactions outside of the California organized markets, including potential claims in the Pacific Northwest. The rights of parties electing not to join the settlement are unaffected and they will neither receive the benefits of the settlement nor be subject to its obligations. PGE believes that any amount that it may owe to non-settling parties related to transactions in the California organized market would not be material to the Company's financial condition, results of operations or cash flows.

Pursuant to the terms of the May 17 Settlement, PGE received a cash payment from the California Power Exchange (PX) of approximately $28 million (including net interest on the Company's past due receivables) in June 2007 and adjusted the reserve related to this matter to zero at June 30, 2007. Based upon previously-recorded reserves and the terms of the May 17 Settlement, PGE recorded a pre-tax increase to income of approximately $6 million in the first quarter of 2007 (reflected as a reduction to Purchased Power and Fuel expense).

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 Federal Power Act (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. Petitions for rehearing at the Ninth Circuit and for U.S. Supreme Court review have been denied.

In the refund case and in related dockets, including the above challenge to market-based rates, the California Attorney General and other parties have argued that refunds should be ordered retroactively to at least May 1, 2000. The May 17 Settlement in the California refund case described above resolves all claims as to market-based rates in western energy markets as between PGE and the named California parties and PGE and the opt-in participants during the settlement period, January 1, 2000 through June 21, 2001; however, it does not settle such claims from market participants who do not opt-in to the settlement, nor does it settle such potential claims arising from transactions with other market participants outside of the California Independent System Operator and PX markets. 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. However, management believes that the outcome will not have a material adverse impact on the Company's financial condition, results of operations or cash flows.

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.

The May 17 Settlement in the California refund case described above resolves all claims as between PGE and the named California parties as to transactions in the Pacific Northwest during the settlement period, January 1, 2000 through June 21, 2001; however, it does not settle such potential claims from other market participants.

Management cannot predict the ultimate outcome of the above matter related to wholesale transactions in 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 and 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, PGE 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 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. Trial has been set for September 2007 and the parties have commenced mediation. The City of Portland has agreed not to seek enforcement of the subpoena while this case is pending.

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 Oregon Department of Environmental Quality (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 a 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 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 condition, results of operations or cash flows.

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 (RI/FS) from the EPA, dated June 27, 2005, in which the Company was named as one of fourteen PRPs with respect to the Harbor Oil site. The letter started a period for the PRPs to participate in negotiations with the EPA to reach a settlement to conduct or finance an RI/FS of the Harbor Oil site. On May 31, 2007, an Administrative Order on Compliance was signed by the EPA and six other parties to implement an RI/FS at the Harbor Oil site.

Sufficient information is currently not available to determine 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 condition, results of operations or cash flows.

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 can choose to adopt this model or establish 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 at Boardman, and requires that the plant reduce its mercury emission by 90% by July 1, 2012. The rules provide limited mercury allowance trading until 2018, after which no trading will be permitted. The rules have been submitted to the EPA for review and determination of compliance with the CAMR requirements.

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 are required to develop implementation plans by December 2007.

The ultimate impact that federal and state regulations on air quality standards will have on future operations, operating costs, or generating capacity of PGE's thermal generating plants is not yet determinable. However, the Company estimates that the capital costs required to meet regional haze rules and install mercury controls at Boardman could be approximately $250 million - $350 million (100% of total project costs, in 2006 dollars). 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 rule, the 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 and Beaver generating plants may cause or contribute to visibility impairment in several protected areas.

Colstrip Plant - Pursuant to negotiations between PPL Montana, LLC (operator of Colstrip Units 3 and 4), Colstrip owners, the EPA, and the Northern Cheyenne Tribe, an agreement has been reached that resolves various matters related to CAA compliance by Colstrip. A consent decree, filed on March 19, 2007 with the U.S. District Court for the District of Montana, was entered on May 14, 2007. The agreement requires that Colstrip Units 3 and 4 reduce NO_x emissions by approximately 55%. PGE anticipates that its share of required capital improvements and other costs will total approximately $5.8 million, which it will seek to recover through the ratemaking process.

Stock-Based Compensation

On June 13, 2007, PGE granted Restricted Stock Units to non-employee directors and a key employee. Each Restricted 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.

For the six months ended June 30, 2007, PGE recorded $1.3 million of stock-based compensation expense. 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 $5.2 million at June 30, 2007, of which $1.4 million, $2.6 million and $1.2 million is expected to be expensed in 2007, 2008, and 2009, respectively.

PGE expects to grant Restricted Stock Units to non-employee directors, as part of their annual compensation arrangement, on or about July 1 each year. It is also anticipated that Restricted Stock Unit or Performance 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 common stock equity.

New Accounting Standards

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 financial assets and liabilities.

FASB Staff Position No. 39-1 (FSP FIN 39-1), Amendment of FASB Interpretation No. 39 (FIN 39), was issued in April 2007 and is effective for fiscal years beginning after November 15, 2007. FSP FIN 39-1 modifies FIN 39, Offsetting of Amounts Related to Certain Contracts, and permits reporting entities to offset the receivable or payable recognized upon payment or receipt of cash collateral against fair value amounts recognized for derivative instruments that have been offset under a master netting arrangement. FSP FIN 39-1 requires financial statement disclosure of a reporting entity's accounting policy (to offset or not offset) as well amounts recognized for the right to reclaim cash collateral, or the obligation to return cash collateral, that have been offset against net derivative positions. PGE is evaluating the application of FSP FIN 39-1 with respect to its assets and liabilities.

Item 3. 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 energy portfolio 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 the first half of 2007 were $6.0 million, $7.6 million, and $3.6 million, respectively, and in the first half of 2006 were $6.7 million, $9.9 million, and $3.8 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 and related costs are recovered in retail rates approved by the OPUC. The timing differences between the recognition of gains and losses on certain derivative instruments and their realization and subsequent recovery in prices are deferred as regulatory assets and regulatory liabilities to reflect the effects of regulation under SFAS 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 June 30, 2007, 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 the commercial paper program subjects the Company to fluctuations in interest rates, reflecting current market conditions, individual instruments carry a fixed rate during their respective terms. At June 30, 2007, PGE had no 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.

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 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 June 30, 2007, the likelihood of significant losses associated with credit risk in trade accounts receivable is remote.

The following table presents PGE's credit exposure for commodity non-trading activities and their subsequent maturity as of June 30, 2007. 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):

				Maturity of Credit Risk Exposure					
Rating	**Credit Risk Before Collateral**	**Percentage of Total Exposure**	**Credit Collateral**	**2007**	**2008**	**2009**	**2010**	**2011**	**After 2011**
Investment Grade	$ 137	98%	$ 32	$ 39	$ 21	$ 21	$ 19	$ 18	$ 19
Non-Investment Grade	1	1%	-	1	-	-	-	-	-
Internally Rated - Investment Grade	1	1%	1	1	-	-	-	-	-
Total	$ 139	100%	$ 33	$ 41	$ 21	$ 21	$ 19	$ 18	$ 19

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.

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 3, Price Risk Management, in the Notes to Condensed Consolidated Financial Statements.

Item 4. Controls and Procedures

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

(b) Changes in Internal Control Over Financial Reporting. There have not been any changes in the Company's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the fiscal quarter to which this report relates that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II

<u>Other Information</u>

Item 1. Legal Proceedings

For further information regarding the following proceedings, see PGE's 2006 Annual Report on Form 10-K.

<u>Citizens' Utility Board of Oregon v. Public Utility Commission of Oregon and Utility Reform Project and Colleen O'Neill v. Public Utility Commission of Oregon</u>, Marion County Oregon Circuit Court, the Court of Appeals of the State of Oregon, the Oregon Supreme Court.

Pursuant to OPUC Order No. 07-157, which ordered that a second phase of the joint remand proceedings be commenced to investigate the OPUC's delegated authority to engage in retroactive ratemaking, a briefing schedule was established, with final briefs submitted on July 20, 2007 and oral argument scheduled for August 9, 2007. For further information, see PGE's Quarterly Report on Form 10-Q for the quarter ended March 31, 2007.

<u>Wah Chang, a division of TDY Industries, Inc. v. Avista Corporation, Avista Energy, Inc., Avista Power, LLC, Dynegy Power Marketing, Inc., El Paso Electric Company, IDACORP, Inc., Idaho Power Company, IDACORP Energy L.P., Portland General Electric Company, Powerex Corporation, Puget Energy, Inc., Puget Sound Energy, Inc., Sempra Energy, Sempra Energy Resources, Sempra Energy Trading Corp., Williams Power Company, Inc.,</u> United States District Court for the District of Oregon, Case No. 04-CV-00619-AS.

Oral argument was held on April 10, 2007 in the appeal of Wah Chang in the Ninth Circuit Court of Appeals.

Item 1A. Risk Factors

There have been no material changes to PGE's risk factors set forth in Part I, Item 1A of the Company's Annual Report on Form 10-K for the year ended December 31, 2006.

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

The 2007 Annual Meeting of Shareholders of Portland General Electric Company was held on May 2, 2007. The election of ten directors, the ratification of the appointment of the firm of Deloitte & Touche LLP as the independent registered public accounting firm of the Company for 2007, and the vote to approve the Portland General Electric Company 2007 Employee Stock Purchase Plan were the only matters voted upon at the meeting. There were 62,504,767 shares of common stock issued and outstanding as of March 16, 2007, the record date for the meeting, with 52,163,496 shares represented at said meeting. The results of the voting are shown below:

Issue	For	Against or Withheld	Abstentions	Broker Non-Votes
Election of Directors:				
John W. Ballantine	51,231,878	931,618		
Rodney L. Brown, Jr.	51,235,514	927,982		
David A. Dietzler	51,235,403	928,093		
Peggy Y. Fowler	51,209,559	953,937		
Mark B. Ganz	51,232,841	930,655		
Corbin A. McNeill, Jr.	49,787,684	2,375,812		
Neil J. Nelson	51,237,485	926,011		
M. Lee Pelton	51,235,838	927,658		
Maria M. Pope	51,236,868	926,628		
Robert T. F. Reid	51,235,971	927,525		
Ratification of Deloitte & Touche LLP	52,123,517	23,085	16,891	
Approval of 2007 PGE Employee Stock Purchase Plan	48,127,366	142,131	76,591	3,817,408

Item 5. Other Information

Amendment to the 2007 Incentive Compensation for Named Executive Officers

On August 1, 2007, the Compensation and Human Resources Committee of PGE's Board of Directors (Committee) approved amendments to the Company's 2007 Annual Incentive Program (2007 Incentive Program) for the executive officers of the Company, including the "named executive officers" as defined in Item 402(a)(3) of Regulation S-K (Named Executive Officers). The 2007 Incentive Program provides for awards based upon the attainment of goals established by the Committee under the Company's 2006 Annual Cash Incentive Master Plan. The original terms of the 2007 awards to the Named Executive Officers were described in a Current Report on Form 8-K filed by the Company on February 28, 2007.

The amendments to the 2007 Incentive Program for the Named Executive Officers revise only the performance goals used to calculate the officers' performance rating. All other material aspects of the program, including the net income goal and the Named Executive Officers' maximum award opportunities as a percentage of base salary, remain unchanged.

Under the revised 2007 Incentive Program for Named Executive Officers, the performance ratings for each of the Named Executive Officers will be based on the extent to which five equally weighted corporate goals have been achieved. Accordingly, the performance ratings for each of the Named Executive Officers will be identical. The five corporate goals, and the measures that will be used to determine their achievement, are described in the following table.

Corporate Goal	**Measure(s)**
High Customer Value	Overall customer satisfaction ranking, based on the average of the Company's survey rankings relative to its peer utilities in the areas of residential, general business, and key customer satisfaction.
Power Quality and Reliability	Quantitative measurements related to customer outages (both number and duration) and momentary power interruptions, utilizing standard utility measurement practices.
Reliable, Reasonably Priced Supply	Generation plant availability (including the effect of both planned and forced outages).
Engaged, Valued Workforce	Employee Work-Life Satisfaction Rating, based on an annual employee survey, to be conducted during the 4^{th} quarter of 2007.
Active Corporate Responsibility	Quantitative measurements related to Occupational Safety and Health Administration Recordable Accidents.

The Company believes that these changes to the 2007 Incentive Program will enable the Committee to measure and reward executive performance in a way that is more streamlined, more objective, and appropriately aligned with the Company's overall operating objectives.

Item 6. Exhibits

(3) Articles of Incorporation and Bylaws

3.1 * Amended and Restated Articles of Incorporation of Portland General Electric Company [Form 8-K filed April 3, 2006, Exhibit (3.1)].

3.2 * Portland General Electric Company Fourth Amended and Restated Bylaws [Form 8-K filed November 20, 2006, Exhibit (3.1)].

(4) Instruments defining the rights of security holders, including indentures

4.1 * Registration Rights Agreement, dated as of June 1, 2007 [Form S-3ASR filed on June 4, 2007, Exhibit (4.11)].

4.2 * Form of Supplemental Indenture (including for of First Mortgage Bond) to be entered into between Portland General Electric Company and HSBC Bank USA, National Association, as Trustee, with respect to First Mortgage Bonds [Form S-3ASR filed on June 4, 2007, Exhibit (4.10)].

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

(10) Material contracts

10.1 * Portland General Electric Company 2007 Employee Stock Purchase Plan [Appendix B to the Proxy Statement, filed on March 30, 2007].

(31) Rule 13a-14(a)/15d-14(a) Certifications

31.1 Certification of Chief Executive Officer of Portland General Electric Company (filed herewith).

31.2 Certification of Chief Financial Officer of Portland General Electric Company (filed herewith).

(32) Section 1350 Certifications

Certifications of Chief Executive Officer and Chief Financial Officer of Portland General Electric Company Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).

* Incorporated by reference as indicated.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PORTLAND GENERAL ELECTRIC COMPANY
(Registrant)

Date: August 3, 2007

By: /s/ James J. Piro
James J. Piro
Executive Vice President, Finance
Chief Financial Officer and Treasurer
(duly authorized
and principal financial officer)

EXHIBIT 31.1

**CERTIFICATION OF
CHIEF EXECUTIVE OFFICER
OF PORTLAND GENERAL ELECTRIC COMPANY**

I, Peggy Y. Fowler, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Portland General Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 3, 2007

/s/ Peggy Y. Fowler
Peggy Y. Fowler
Chief Executive Officer and
President

EXHIBIT 31.2

**CERTIFICATION OF
CHIEF FINANCIAL OFFICER
OF PORTLAND GENERAL ELECTRIC COMPANY**

I, James J. Piro, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Portland General Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 3, 2007

/s/ James J. Piro
James J. Piro
Executive Vice President, Finance
Chief Financial Officer and Treasurer

EXHIBIT 32

CERTIFICATIONS OF
CHIEF EXECUTIVE OFFICER AND CHIEF FINANCIAL OFFICER
OF PORTLAND GENERAL ELECTRIC COMPANY
PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

We, Peggy Y. Fowler, Chief Executive Officer and President, and James J. Piro, Executive Vice President, Finance, Chief Financial Officer and Treasurer, of Portland General Electric Company (the "Company"), hereby certify that the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2007, as filed with the Securities and Exchange Commission on the date hereof pursuant to Section 13(a) of the Securities Exchange Act of 1934 (the "Report"), fully complies with the requirements of that section.

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

/s/ Peggy Y. Fowler	/s/ James J. Piro
Peggy Y. Fowler	James J. Piro
Date: August 3, 2007	Date: August 3, 2007