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 September 30, 2001

OR

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

For the Transition period from ________________ to _______________

Commission File Number 1-5532-99

PORTLAND GENERAL ELECTRIC COMPANY

(Exact name of registrant as specified in its charter)

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

121 SW Salmon Street, Portland, Oregon 97204

(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.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of October 31, 2001: 42,758,877 shares of Common Stock, $3.75 par value. (All shares are owned by Enron Corp.)

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Definitions

BPA	Bonneville Power Administration
CUB	Citizens' Utility Board
Enron	Enron Corp.
FERC	Federal Energy Regulatory Commission
KWh	Kilowatt-Hour
Mill	One tenth of one cent
MWh	Megawatt-hour
NW Natural	Northwest Natural Gas Company
OPUC or the Commission	Public Utility Commission of Oregon
PGE or the Company	Portland General Electric Company
Trojan	Trojan Nuclear Plant
URP	Utility Reform Project

PART I

Portland General Electric Company and Subsidiaries

Consolidated Income Statement

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2001	**2000**	**2001**	**2000**
	(Millions of Dollars)			

Operating Revenues	$ 905	$ 728	$ 2,502	$ 1,555
Operating Expenses				
Purchased power and fuel	806	523	2,020	976
Production and distribution	29	31	89	90
Administrative and other	30	36	95	105
Depreciation and amortization	29	39	115	116
Taxes other than income taxes	15	19	49	52
Income taxes	(15)	27	30	71
	894	675	2,398	1,410
Net Operating Income	11	53	104	145
Other Income (Deductions)				
Miscellaneous	-	(5)	2	2
Income taxes	2	2	4	3
	2	(3)	6	5
Interest Charges				
Interest on long-term debt and other	16	16	52	47
Interest on short-term borrowings	2	2	2	7
	18	18	54	54
Net income (loss) before cumulative effect of a change in accounting principle	(5)	32	56	96
Cumulative effect of a change in accounting principle, net of related taxes of $(6)	-	-	11	-
Net Income (loss)	(5)	32	67	96
Preferred Dividend Requirement	1	1	2	2
Income (Loss) Available for Common Stock	$ (6)	$ 31	$ 65	$ 94

Consolidated Statement of Retained Earnings

(Unaudited)

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2001	**2000**	**2001**	**2000**
	(Millions of Dollars)			
Balance at Beginning of Period	$ 490	$ 424	$ 459	$ 401
Net Income (Loss)	(5)	32	67	96
	485	456	526	497
Dividends Declared				
Common stock	-	20	40	60
Preferred stock	1	1	2	2
	1	21	42	62
Balance at End of Period	$ 484	$ 435	$ 484	$ 435

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

Portland General Electric Company and Subsidiaries

Consolidated Balance Sheet

(Unaudited)

	September 30, 2001	December 31, 2000
	(Millions of Dollars)	
Assets		
Electric Utility Plant - Original Cost		
Utility plant (includes construction work in progress of $124 and $78)	$ 3,575	$ 3,423
Accumulated depreciation	(1,635)	(1,532)
	1,940	1,891
Other Property and Investments		
Contract termination receivable	36	57
Receivable from parent	72	80
Nuclear decommissioning trust, at market value	38	33
Trust owned life insurance	77	86
Miscellaneous	34	21
	257	277
Current Assets		
Cash and cash equivalents	2	60
Accounts and notes receivable	341	287
Unbilled and accrued revenues	42	60
Assets from price risk management activities	212	279
Inventories, at average cost	44	31
Deposits	69	-
Prepayments and other	85	61
Deferred income taxes	6	-
	801	778
Deferred Charges		
Unamortized regulatory assets	575	484
Miscellaneous	17	22
	592	506
	$ 3,590	$ 3,452
Capitalization and Liabilities		
Capitalization		
Common stock equity		
Common stock, $3.75 par value per share, 100,000,000 shares authorized; 42,758,877 shares outstanding	$ 160	$ 160
Other paid-in capital - net	480	480
Retained earnings	484	459
Cumulative preferred stock		
Subject to mandatory redemption	29	30
Long-term obligations	776	798
	1,929	1,927
Current Liabilities		
Long-term debt due within one year	23	52
Preferred stock maturing within one year	1	-
Short-term borrowings	301	16
Accounts payable and other accruals	293	286
Liabilities from price risk management activities	249	266
Customer deposits	9	139
Deferred income taxes	-	5
Accrued interest	15	14
Dividends payable	1	1

Accrued taxes	23	8
	915	787
Other		
Deferred income taxes	383	360
Deferred investment tax credits	24	27
Trojan decommissioning and transition costs	209	218
Unamortized regulatory liabilities	31	34
Miscellaneous	99	99
	746	738
	$ 3,590	$ 3,452

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

Portland General Electric Company and Subsidiaries

Consolidated Statement of Cash Flows

(Unaudited)

	Nine Months Ended September 30,	
	2001	**2000**
	(Millions of Dollars)	
Cash Flows From Operating Activities:		
Reconciliation of net income to net cash provided by (used in) operating activities		
Net income	$ 67	$ 96
Non-cash items included in net income:		
Cumulative effect of a change in accounting principle, net of tax	(11)	-
Depreciation and amortization	115	116
Deferred income taxes	9	(8)
Net (assets) liabilities from price risk management activities	47	(17)
Power cost adjustment	(90)	-
Other non-cash income and expenses (net)	(4)	11
Changes in working capital:		
Net margin deposit activity	(199)	26
(Increase) Decrease in receivables	(36)	(99)
Increase (Decrease) in payables	23	90
Other working capital items - net	(37)	(22)
Other - net	3	8
Net Cash Provided by (Used in) Operating Activities	(113)	201
Cash Flows From Investing Activities:		
Capital expenditures	(146)	(109)
Proceeds from sales of assets	-	27
Other - net	9	2
Net Cash Used in Investing Activities	(137)	(80)
Cash Flows From Financing Activities:		
Net increase (decrease) in short-term borrowings	285	(174)
Repayment of long-term debt	(51)	(30)
Issuance of long-term debt	-	150
Dividends paid	(42)	(62)
Net Cash Provided by (Used in) Financing Activities	192	(116)

Increase (Decrease) in Cash and Cash Equivalents	(58)	5
Cash and Cash Equivalents, Beginning of Period	60	-
Cash and Cash Equivalents, End of Period	$ 2	$ 5
Supplemental disclosures of cash flow information		
Cash paid during the period:		
Interest, net of amounts capitalized	$ 48	$ 47
Income taxes	35	80

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

Portland General Electric Company and Subsidiaries

Notes to Consolidated Financial Statements

(Unaudited)

Note 1 - Principles of Interim Statements

The interim financial statements have been prepared by PGE and, in the opinion of management, reflect all material adjustments which are necessary for a fair statement of results for the interim periods presented. 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 the estimates of operating time expired, benefit received or activity associated with the interim period. Accordingly, such costs are subject to year-end adjustment. It is PGE's opinion that, when the interim statements are read in conjunction with the 2000 Annual Report on Form 10-K, and the other reports filed with the Securities and Exchange Commission since its 2000 Form 10-K was filed, the disclosures are adequate to make the information presented not misleading.

Reclassifications - Certain amounts in prior years have been reclassified to conform to current year presentation.

Note 2 - Legal Matters

Trojan Investment Recovery - In 1993, 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. The filing was a result of PGE's decision earlier in the year to cease commercial operation of Trojan as a part of its least cost planning process. 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 requested reviews have been filed in Marion County, Oregon Circuit Court, Oregon Court of Appeals and with 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 have been the Citizens' Utility Board (CUB) and the Utility Reform Project (URP). Rulings issued to date by the Circuit Court and the Court of Appeals have been inconsistent on the issue. The Court of Appeals issued the latest ruling in 1998, stating that the OPUC does not have the authority to allow PGE to recover a return on the Trojan investment, but upheld the OPUC's authorization of PGE's recovery of the Trojan investment. PGE and the OPUC requested the Oregon Supreme Court to conduct a review of the Court of Appeals decision on the return on investment issue. In addition, URP requested the Oregon Supreme Court to review the Court of Appeals decision on the return o f investment issue. The Supreme Court has indicated it will conduct a review.

In 2000, PGE entered into settlement agreements with CUB and the staff of the OPUC of the litigation related to PGE's recovery of its investment in the Trojan plant. Under the agreements, CUB agreed to withdraw from the litigation and support the settlement as the means to resolve the Trojan litigation. The settlement, which was approved by the OPUC, 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 about $80 million of remaining obligation under terms of the Enron/PGC merger. The settlement also allows PGE recovery of approximately $47 million in income tax benefits related to the Trojan investment which had been flowed to customers in prior years; such amount is being recovered from PGE customers, with no return on the unamortized balance, over an approximate five year period. 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. The URP has challenged the settlement agreements and the OPUC order. Collection of decommissioning costs at Trojan is unaffected by the settlement agreements or the OPUC order.

With CUB's withdrawal, the URP is the one remaining significant adverse party in the litigation. The URP has indicated it plans to continue to challenge the orders that allow PGE recovery of and a return on its investment in Trojan. The Oregon Supreme Court's review is on hold pending resolution of the URP's latest challenge with the OPUC.

Management cannot predict the ultimate outcome of the above litigation. However, it believes that the outcome of this matter will not have a material adverse impact on the financial condition of the Company, but may have a material impact on the results of operations for a future reporting period.

Note 3 - Price Risk Management

PGE engages in non-trading and trading activities by utilizing derivative financial instruments in its electric utility business. Under Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities", which was adopted on January 1, 2001, derivative instruments are recorded on the balance sheet as an asset or liability measured at estimated fair value, with changes in the derivative's fair value recognized currently in earnings, unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement. As discussed below, the effects of changes in fair value of derivative instruments entered into to hedge the company's future retail resource requirements are subject to regulation and therefore are deferred pursuant to SFAS 71, Accounting for the Effects of Certain Types of Regulation.

Non-Trading Activities

As PGE's primary business is to serve its retail customers, it enters into derivative instruments, including electricity forward, natural gas forward, swap and futures contracts to manage its exposure to commodity price risk to achieve lower net power costs for customers. Effective October 1, 2001, PGE's base rates changed as a result of an OPUC general rate order to reflect an update of PGE's net variable power costs that included electricity and natural gas contracts that will settle over the next 15-month period. In addition to this change, the OPUC approved a 15-month power cost adjustment mechanism from October 1, 2001 to help PGE mitigate its exposure to price risks associated with volatility of power and natural gas prices. The power cost mechanism provides an incentive for the utility to continue to actively manage resources it has procured to serve its retail load for the next 15 months to lower retail power costs. The mechanism allows PGE to recover or refund a portion of the difference in changes in power costs and energy revenues from a baseline amount as a result of the continuing management of its resources and changes in the forecasted load. The collection or refund is expected to be completed over the same 15-month period through adjustments to retail customer rates. Each year thereafter, PGE will provide updates of its net variable power costs to the OPUC for inclusion in base rates for the year.

SFAS 133 requires unrealized gains and losses on derivative instruments that do not qualify for either the normal purchase and sale exception or hedge accounting to be recorded in earnings in the current period. The OPUC approved rates based on the value of all the company's resources, including derivative instruments that will settle during the 15-month period. The timing difference between the recognition of gains and losses on derivative instruments and their realization and subsequent collection in rates will be recorded as a regulatory asset or regulatory liability to reflect the effects of regulation under SFAS 71. As a result, in the third quarter of 2001 PGE began recording a regulatory asset or regulatory liability pursuant to SFAS 71 to fully offset the net effects of unrealized gains and losses from changes in fair values of these contracts recorded prior to settlement in earnings and Other Comprehensive Income (OCI). The regulatory asset or regulatory liability is reflected in Unamortized regulatory assets or Unamortized regulatory liabilities, respectively, on the Balance Sheet with offsets in Purchased power and fuel on the Income Statement for the earnings portion and in Other Comprehensive Income on the Balance Sheet for the OCI portion.

In the first nine months of 2001, PGE recorded $8 million in unrealized losses in earnings on natural gas swaps in its retail portfolio. The unrealized losses were fully offset in the third quarter by the recording of a SFAS 71 regulatory asset, as discussed above.

Derivative activities recorded in OCI for the nine-month period ended September 30, 2001 totaled $21 million of unrealized losses from cash flow hedges that were fully offset in the third quarter by the recording of a regulatory asset on the Balance Sheet. No amount was reclassified into earnings as a result of hedge ineffectiveness. For the nine-month period ended September 30, 2001, cash flow hedges of $31 million were discontinued and reclassified into earnings due to the probability that the original forecasted transactions will not occur. Of the transition adjustment recorded at January 1, 2001, losses totaling $8 million were reclassified into earnings in the first nine months of 2001, with an estimated $2 million loss expected to be reclassified to earnings in the remaining three months of the year. The Company estimates that of the $21 million of unrealized losses at September 30, 2001 in OCI, losses totaling $8 million are expected to be reclassified into earnings within the next twelve months.

Trading Activities

PGE's trading activities utilize electricity forward and option contracts and natural gas forward, swap and futures contracts to take advantage of price movements in electricity and natural gas. Trading activities are currently not subject to regulation. For the third quarter of 2001, PGE recorded in earnings a $2 million gain in trading activities, as $51 million in realized gains were largely offset by $49 million in unrealized losses. In the first nine months of 2001, a loss of $9 million was recorded in earnings, with $22 million in unrealized losses partially offset by $13 million in realized gains.

Note 4 - Receivables - California Wholesale Market

As of September 30, 2001, PGE had approximately $110 million of accounts receivable that may be affected by the financial condition of two major California utilities. Remaining payments totaling approximately $40 million were owed by Southern California Edison Company (SCE) under terms of a 1996 agreement providing for the termination of a Power Sales Agreement between the two companies. SCE has made its scheduled monthly payments in 2001 under the termination agreement. In addition, balances of approximately $62 million and $8 million were owed the Company by the California Independent System Operator (ISO) and California Power Exchange (PX), respectively, for wholesale electricity sales made from November 2000 through February 2001, including sales made under federal order. The Company estimates the majority of this amount was for sales by the ISO and PX to SCE and Pacific Gas & Electric Company (PG&E).

On March 9, 2001, the PX filed for bankruptcy, and on April 6, 2001, PG&E filed a voluntary petition for relief under the provisions of Chapter 11 of the U.S. Bankruptcy Code. Pursuant to Chapter 11 of the U.S. Bankruptcy Code, PG&E retains control of its assets and is authorized to operate its business as a debtor in possession while subject to the jurisdiction of the Bankruptcy Court.

PGE is pursuing collection of all past due amounts. Management is continually assessing PGE's exposure relative to its California receivables and has established a credit reserve for amounts due under its wholesale electricity contracts.

The Company has retained legal counsel on the bankruptcy matter and has numerous options, including legal, regulatory, and other means to pursue collection of amounts ultimately not received. Due to uncertainties surrounding both the bankruptcy filing and the California power situation, management cannot predict the ultimate realization of these receivables.

Management believes that the outcome of this matter will not have a material adverse impact on the financial condition of the Company, but may have a material impact on the results of operations for future reporting periods.

Note 5 - Refunds on Wholesale Transactions

California

In a June 19, 2001 FERC order adopting a price mitigation program for 11 states within the Western Systems Coordinating Council area, the issue of refunds for spot market sales made between October 2, 2000 through June 20, 2001 was referred to a settlement judge. Subsequently, the settlement judge recommended to the FERC that the potential for refunds during the period October 2, 2000 through June 20, 2001 be set for hearing.

On July 25, 2001, the FERC issued an order establishing the scope of and methodology for calculating refunds related to non federally-mandated transactions in the spot markets operated by the ISO and the PX. In addition, an evidentiary hearing proceeding was ordered to develop a factual record to provide the basis for the refund calculation. The Company's potential refund obligation, using the FERC methodology, is currently estimated to be in the range of $20 to $30 million, with final determination to be made after FERC review of calculations filed by the ISO. PGE will have the opportunity to challenge the FERC's determination of the amount of any proposed refunds.

Pacific Northwest

In the July 25, 2001 order, the FERC called for a preliminary evidentiary hearing to explore whether there may have been unjust and unreasonable charges for spot market sales of electricity in the Pacific Northwest from December 25, 2000 through June 20, 2001. During this period, PGE both sold and purchased electricity in the Pacific Northwest. Upon completion of hearings, the appointed Administrative Law Judge issued a recommended order that the claims for refunds be dismissed. That recommendation, which would eliminate any potential refunds to be paid or received by PGE as a result of this proceeding, is now before the Commission for action.

Any refunds paid or received by PGE applicable to spot market electricity transactions on and after January 1, 2001 in California and the Pacific Northwest are eligible for inclusion in the calculation of net variable power costs under the Company's power cost mechanism. This could potentially mitigate the financial effect of any refunds made or received by the Company.

Management cannot predict the ultimate outcome of these matters. 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 for future reporting periods.

Note 6 - Credit Facilities and Debt

On August 20, 2001 and October 1, 2001, PGE entered into new $75 million and $25 million credit facilities, both with commercial banks; the Company is currently seeking an extension or replacement of both facilities upon their December 14, 2001 expiration. These new facilities, along with existing facilities totaling $350 million, provide PGE with total committed credit lines of $450 million. PGE's credit facilities are used as backup for commercial paper and borrowings from commercial banks under uncommitted lines of credit, and serve as the Company's primary source of liquidity. There are no changes to current debt covenants or other restrictions.

Note 7 - Subsequent Events

Enron owns all of the issued and outstanding common stock of PGE. Enron recently made several announcements causing PGE to assess the financial impact of its existing relationship with Enron. These announcements included a loss for the quarter ended September 30, 2001, an investigation by the Securities and Exchange Commission (SEC), a restatement of Enron's historical financial statements and downgrades in Enron's investment-grade credit ratings.

On October 16, 2001, Enron announced its third quarter earnings which included non-recurring charges totaling $1.01 billion after-tax, resulting in a net loss for the quarter. A portion of the loss related to the early termination of certain structured finance arrangements with a previously disclosed related entity. Following a decrease in the trading prices for Enron's common stock, on October 22, 2001, Enron announced that the SEC had requested that Enron voluntarily provide information regarding certain related party transactions and that it would cooperate fully with the SEC. On October 31, 2001, Enron announced that its board had elected a new director who would chair a special committee to examine and take appropriate action with respect to transactions between Enron and entities connected to related parties. In addition to reviewing the transactions in question, the special committee was charged with communicating with the SEC and recommending any other actions it deems appropri ate. The special committee retained its own counsel and an independent accounting firm. Enron also reported that the SEC had opened a formal investigation into certain of the matters that previously were the subject of its informal inquiry.

In a SEC Form 8-K filed on November 8, 2001, Enron provided additional information regarding various related party and off-balance sheet transactions in which it was involved. In addition, Enron indicated that it would restate prior period financial statements from 1997 through 2000 and the first two quarters of 2001 to reflect a previously announced $1.2 billion reduction to shareholders' equity, as well as to consolidate three previously unconsolidated entities. Enron's restatements have not required any restatement of PGE's financial statements.

On November 9, 2001, Enron reported that it is being acquired by Dynegy Inc., a Houston-based energy trading and power company, subject to shareholder approval of both companies, antitrust approval and satisfaction of other conditions.

At this time, management cannot predict what impact, if any, these events may have on PGE's financial statements. Further information regarding these matters can be obtained by reference to Enron's third quarter 2001 SEC Form 10-Q when filed.

Note 8 - Proposed Acquisition of PGE

On October 5, 2001, Enron and NW Natural entered into a Stock Purchase Agreement (the "Stock Purchase Agreement") providing for the acquisition by NW Natural of all of the issued and outstanding common stock of PGE.

Under terms of the Stock Purchase Agreement, Enron will sell PGE to NW Natural for $1.875 billion, comprised of $1.55 billion in cash, $250 million of equity securities to be issued to Enron, and the assumption by NW Natural of a $75 million payment obligation from Enron to PGE, remaining from Enron's purchase of PGE in 1997. PGE will retain its approximately $1.1 billion in existing debt and preferred stock.

The transaction is subject to a number of conditions, including obtaining regulatory approvals from the SEC, the Federal Energy Regulatory Commission, the Nuclear Regulatory Commission, the OPUC, and the Washington Utilities and Transportation Commission. It is expected to close in the second half of 2002, following the receipt of required regulatory approvals, as well as the approval of NW Natural's shareholders.

Management does not expect the recent events at Enron, as described in Note 7, Subsequent Events, will affect the proposed purchase of PGE by NW Natural, as described above.

Portland General Electric Company and Subsidiaries

Management's Discussion and Analysis of Financial

Condition and Results of Operations

Results of Operations

The following review of PGE's results of operations should be read in conjunction with the Consolidated Financial Statements.

Due to seasonal fluctuations in electricity sales, as well as the volatility in prices of wholesale energy and natural gas, quarterly operating earnings are not necessarily indicative of results to be expected for calendar year 2001.

2001 Compared to 2000 for the Three Months Ended September 30

PGE had a net loss of $5 million in the third quarter of 2001 compared to net income of $32 million in the third quarter of 2000. The effect of significantly higher prices for wholesale electricity sales was more than offset by higher power costs and other expenses during the quarter.

Total operating revenues increased $177 million (24%) compared to the third quarter of 2000, due to both higher prices for energy sold in the wholesale market and revenues accrued under terms of the Company's power cost mechanism. Wholesale revenues increased $110 million (24%), as prices rose 73% from last year's third quarter due to the combined effect of higher natural gas prices, below normal hydro conditions, and market forces within the region. Wholesale sales volume decreased 29% as higher thermal production was used to replace lower hydro generation to meet third quarter retail load requirements. Retail revenues decreased $20 million on a 3% decrease in energy sales, as commercial, industrial, and residential load all declined from last year. A state-wide decline in economic activity, as well as conservation efforts, more than offset an approximate 7,700 increase in the average number of retail customers served. Lower industrial usage was due primarily to the effect of the De mand Buyback program (see "Retail Customer Growth and Energy Sales" in the Financial and Operating Outlook section for further information). Other operating revenues increased $87 million due to revenues accrued under the power cost mechanism, in which a portion of net variable power costs exceeding a certain baseline amount are deferred for future collection from customers.

Megawatt-Hours Sold (thousands)

	2001	2000
Retail	4,509	4,657
Wholesale	4,062	5,703

Purchased power and fuel costs increased $283 million (54%), as the average cost of purchased power and fuel increased 70% from last year; included in the increase is an $8 million reduction in net gains on electricity and natural gas trading contracts. Partially offsetting these increases was an 18% decrease in total system load, as both wholesale and retail energy sales decreased from last year's third quarter, and an approximate $8 million reduction resulting from the deferral as a regulatory asset of the net unrealized loss on non-trading natural gas swaps during the first nine months of 2001 (see Note 3, Price Risk Management, in the Notes to Financial Statements for further information). Company generation increased 7%, with increased coal-fired and thermal generation partially offset by decreased hydro production. Total generation increased from 27% to 36% of PGE's total system requirement during the third quarter of 2001.

During the fourth quarter of 2000 and through the first quarter of 2001, PGE entered into electricity and natural gas forward contracts for the third quarter of 2001 at forward prices reflecting the higher market prices prevailing during this period. Western wholesale power prices have since moderated significantly due to the combined effects of federal price mitigation, mild weather, additional generation capacity, increased natural gas supplies, and conservation efforts. Combined with deteriorating hydro conditions and increased thermal generation, the inability to sell wholesale power at prices covering the cost of such power resulted in substantially higher net variable power costs in the third quarter of 2001 than in last year's third quarter.

Megawatt/Variable Power Costs

	Megawatt-Hours (thousands)		Average Variable Power Cost (Mills/kWh)	
	2001	2000	2001	2000
Generation	3,146	2,934	14.2	15.1
Firm Purchases	5,208	6,745	127.8	50.1
Spot Purchases	494	1,065	30.6	126.6
Total Send-Out	8,848	10,744	83.2*	48.8*

(*includes wheeling costs)

Operating expenses (excluding purchased power and fuel, depreciation and amortization, and taxes) decreased $8 million, related primarily to lower employee benefit costs and a higher capitalization rate for certain distribution overhead costs. Partially offsetting these reductions was an increase in energy efficiency expenditures (such expenditures were deferred and amortized prior to October 1, 2000, but are now expensed and recovered by additional revenues).

Depreciation and amortization expense decreased $10 million, due primarily to an approximate $12 million regulatory credit related to PGE's SAVE program, by which the Company is allowed recovery in rates of certain costs related to the installation of energy efficiency measures.

Taxes other than income taxes decreased $4 million due to reduced payroll and property taxes.

Taxes on operating income provided a $42 million tax benefit due to the loss in the current quarter.

Other income (net of tax) increased $5 million. In the third quarter of 2000, the Company wrote off its remaining $5 million investment in the Trojan plant as part of a settlement agreement. In addition, results for the current year include $5 million in interest income related to the Company's power cost mechanism, as well as the merger and contract termination receivables. Partially offsetting these increases was an approximate $6 million reduction in earnings on trust owned life insurance assets.

<u>2001 Compared to 2000 for the Nine Months Ended September 30</u>

PGE earned $67 million during the nine months ended September 30, 2001, compared to earnings of $96 million in 2000. Results for the current year include an $11 million cumulative effect of a change in accounting principle resulting from the Company's adoption of SFAS No. 133 on January 1, 2001.

Income before the effect of the accounting change was $56 million, a $40 million decrease from the first nine months of 2000. The effect of significantly higher prices for wholesale electricity sales was more than offset by higher power costs.

Total operating revenues increased $947 million (61%) compared to the first nine months of 2000 due to higher prices for energy sold in the wholesale market. Wholesale revenues increased $880 million (from $762 million to $1,642 million), as prices more than tripled from last year's first nine months due to the combined effect of higher natural gas prices, below normal hydro conditions, and market forces within the region. Wholesale sales volume decreased 34% as higher thermal production was used to replace lower hydro generation to meet retail load requirements in the first nine months of the year. Retail revenues decreased $28 million (4%) on energy sales that decreased about 3% from last year's first nine months, as lower industrial usage (due to the Demand Buy Back program), declining economic activity, mild weather, and conservation more than offset an approximate 5,592 increase in the average number of retail customers served. (See "Retail Customer Growth and Energy Sales" in t he Financial and Operating Outlook section for further information). Other operating revenues increased $94 million due primarily to $87 million revenues accrued under the Company's power cost mechanism, in which a portion of net variable power costs exceeding a certain baseline amount are deferred for future collection from customers.

Megawatt-Hours Sold (thousands)

	<u>2001</u>	<u>2000</u>
Retail	14,172	14,543
Wholesale	9,836	14,893

Purchased power and fuel costs increased $1,044 million (107%) due to significantly higher power prices. Due to both higher regional power and gas market prices, the average cost of firm power purchases more than tripled from last year's first nine months. Combined with higher prices for spot market purchases, reduced hydro production, and increased thermal generation, PGE's average variable power cost increased 144% (for further information, see "Power Supply" in the Financial and Operating Outlook section). Included in the increased cost is a $37 million reduction in net gains on electricity and natural gas trading contracts. Partially offsetting the effect of these increases was an 18% decrease in total system load, as both wholesale and retail energy sales decreased from last year's first nine months, and an approximate $8 million reduction resulting from the deferral as a regulatory asset of the net unrealized loss on non-trading natural gas swaps during the first nine months of 2001 (see Note 3, Price Risk Management, in the Notes to Financial Statements for further information).

The following table indicates PGE's total system load (including both retail and wholesale) for the first nine months of 2001. Company generation increased 15%, with increased natural gas combustion turbine and coal-fired generation partially offset by a 26% decrease in hydro production caused by lower stream flows.

Megawatt/Variable Power Costs

Megawatt-Hours	Average Variable
(thousands)	Power Cost (Mills/kWh)

	2001	2000	2001	2000
Generation	9,261	8,023	19.5	13.8
Firm Purchases	14,045	20,112	111.3	32.9
Spot Purchases	1,613	2,357	130.9	84.3
Total Send-Out	24,919	30,492	79.6*	32.6*

(*includes wheeling costs)

Operating expenses (excluding purchased power and fuel, depreciation and amortization, and taxes) decreased $11 million. In the first nine months of 2000, the Company recorded provisions of $2.4 million and $1.5 million, respectively, for deferred costs related to the proposed sale of its 20% interest in Units 3 and 4 of the Colstrip power plant and for increased insurance claims. (The Colstrip sale was denied by the OPUC and the Company was granted rate recovery of a portion of such costs). In addition, operating expenses for the first nine months of last year were reduced by a $5 million refund received from Nuclear Electric Insurance Limited, in which PGE terminated its membership in last year's fourth quarter. Lower expenses in this year's first nine months include lower employee benefit costs, a higher capitalization rate for certain distribution costs, lower outage repair and distribution maintenance costs due to milder weather, and the reversal of $1.8 million of the provision r ecorded last year related to the proposed sale of the Colstrip power plant. Partially offsetting these reductions was an increase in energy efficiency expenditures (such expenditures were deferred and amortized prior to October 1, 2000 but are now expensed and recovered by additional revenues). In addition, there were increases this year for customer service and support activities and for boiler repairs and combustion turbine inspections at the Company's thermal generating plants.

Depreciation and amortization expense decreased $1 million, due primarily to an approximate $12 million regulatory credit related to PGE's SAVE program, by which the Company is allowed recovery in rates of certain costs related to the installation of energy efficiency measures. Partially offsetting this reduction was a $9 million increase related to the effect of the removal of certain regulatory liabilities from the balance sheet as part of last year's Trojan settlement agreement.

Other income (net of tax) increased $1 million. In the third quarter of 2000, the Company wrote off its remaining $5 million investment in the Trojan plant as part of a settlement agreement. Changes in the market value of trust owned life insurance assets resulted in an approximate $9 million loss in the first nine months of 2001, compared to a $5 million gain last year. Interest income increased $10 million, including that related to the Company's power cost mechanism and interest on the merger and contract termination receivables.

An increase in interest on long-term debt and other, due to both interest on wholesale trading deposits and to the March 2000 issuance of $150 million in unsecured notes, was offset by reduced interest on a lower average level of commercial paper outstanding during the first nine months of 2001.

Cash Flow

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

A significant portion of cash from operations comes from depreciation and amortization of utility plant, charges which are recovered in customer revenues but require no current cash outlay. Changes in accounts receivable and accounts payable can also be significant contributors or users of cash.

Cash used in operating activities totaled $113 million in the first nine months of 2001, compared to $201 million provided in the same period last year. This was caused primarily by the repayment of $130 million in deposits received from wholesale electricity customers held at year-end 2000, as well as the payment of $69 million in deposits to wholesale customers in the first nine months of 2001; such payments were funded primarily by increased commercial paper borrowings. Increased payments for purchased power, fuel, stores materials, and taxes, as well as major maintenance and overhaul expenditures at the Coyote Springs combustion turbine plant, accounted for most of the remaining increase in cash used in operating activities.

Investing Activities consist primarily of improvements to PGE's distribution, transmission, and generation facilities. Capital expenditures in the first nine months of 2001 exceeded last year primarily due to the continued expansion and improvement of PGE's distribution system to support new customers. In addition, costs of a new customer information and billing system, a new 24.5 megawatt combustion turbine plant, and certain large transmission substation and production plant improvements were incurred in this year's first nine months. Proceeds from sales of assets last year consisted primarily of amounts received from the sale of a portion of PGE service territory to two public utility districts and from the sale of the Company's interest in certain rights and non-generating facilities at its Coyote Springs combustion turbine generating plant.

Financing Activities provide supplemental cash for day-to-day operations and capital requirements as needed. PGE relies on commercial paper borrowings and cash from operations to manage its day-to-day financing requirements. During the first nine months of 2001, commercial paper borrowings increased $285 million, which was utilized primarily to refund deposits received from wholesale electricity customers in 2000 and to make deposits with such customers during the first nine months of 2001. In addition, PGE repaid $45 million in matured First Mortgage Bonds, paid $40 million in common stock dividends to its parent and paid $2 million in preferred stock dividends during the first nine months of 2001. Payment of conservation bonds, totaling $6 million in the first nine months of 2001, is also reflected in "Repayment of long-term debt".

In February 2001, the Company filed a $250 million shelf registration statement with the Securities and Exchange Commission, increasing PGE's long-term debt capacity to $300 million. The Company is currently not issuing debt under its shelf registration statement due to currently prevailing market conditions and other circumstances.

On June 13, 2001, PGE amended and restated its 364-day $100 million credit agreement with a group of commercial banks, providing for a 364-day extension and an increase to $200 million. On July 12, 2001, the $200 million credit agreement was further amended and restated to permit the issuance of up to $100 million in letters of credit. On August 20, 2001 and October 1, 2001, PGE entered into new $75 million and $25 million credit facilities, both with commercial banks; the Company is currently seeking an extension or replacement of both facilities upon their December 14, 2001 expiration. These new facilities, along with an existing $150 million facility maturing in July 2003, provide PGE with total committed credit lines of $450 million. PGE's credit facilities are used primarily as backup for commercial paper and borrowings from commercial banks under uncommitted lines of credit, and serve as the Company's primary source of liquidity. There are no changes to current debt covenants or other restrictions.

At September 30, 2001, the Company had outstanding commercial paper of $301 million and had used approximately $94 million in letters of credit under its committed credit lines. As a result, PGE had utilized approximately $395 million of its $450 million credit line capacity. No common stock dividend was declared in the third quarter of 2001; management is currently evaluating future declaration of common dividends in light of expected cash requirements and other considerations.

On October 8, 2001, in response to the announced purchase and sale agreement of PGE to NW Natural and uncertainties surrounding the transaction, credit rating agencies reviewed their ratings of the Company. Standard & Poor's (S&P) placed PGE's ratings on CreditWatch Negative, Moody's Investors Services (Moody's) placed the Company's ratings on review for possible downgrade, and Fitch placed all ratings on Rating Watch Negative. Fitch also downgraded PGE's ratings with the exception of commercial paper. On November 13, 2001, Fitch further downgraded the Company's ratings and revised the Rating Watch status to Evolving. This action was the result of ongoing uncertainty at PGE's parent. Fitch rates the Company's senior secured debt 'BBB+', senior unsecured debt 'BBB', preferred stock 'BBB-', and commercial paper 'F2'. S&P currently rates PGE's senior secured debt 'A', senior unsecured debt 'A-', preferred stock 'BBB+', and commercial paper 'A-1'. Moody's rates the Company's senior secured debt 'A2', senior unsecured debt 'A3', preferred stock 'Baa2', and commercial paper 'P-1'.

The issuance of additional First Mortgage Bonds and preferred stock requires PGE to meet earnings coverage and security provisions set forth in the Articles of Incorporation and the Indenture securing its First Mortgage Bonds. As of September 30, 2001, PGE has the capability to issue preferred stock and additional First Mortgage Bonds in amounts sufficient to meet its anticipated capital requirements.

Financial and Operating Outlook

Proposed Acquisition

On October 5, 2001, Enron and NW Natural entered into a Stock Purchase Agreement (the "Stock Purchase Agreement") providing for the acquisition by NW Natural of all of the issued and outstanding common stock of PGE.

Under terms of the Stock Purchase Agreement, Enron will sell PGE to NW Natural for $1.875 billion, comprised of $1.55 billion in cash, $250 million of equity securities to be issued to Enron, and the assumption by NW Natural of a $75 million payment obligation from Enron to PGE, remaining from Enron's purchase of PGE in 1997. PGE will retain its approximately $1.1 billion in existing debt and preferred stock.

The transaction is subject to a number of conditions, including obtaining regulatory approvals from the Securities and Exchange Commission, the Federal Energy Regulatory Commission, the Nuclear Regulatory Commission, the OPUC, and the Washington Utilities and Transportation Commission. It is expected to close in the second half of 2002, following the receipt of required regulatory approvals as well as the approval of NW Natural's shareholders.

In OPUC proceedings relating to utility merger and acquisitions, the Commission has traditionally imposed conditions that separate the finances of Oregon utilities from their parent companies. PGE is currently restricted from paying dividends or making other distributions to Enron without prior OPUC approval to the extent that such payment or distribution would reduce the Company's common stock equity below 48% of its total capitalization. Although the Company believes that similar restrictions will be imposed by the OPUC in connection with the proposed acquisition, management cannot predict with certainty the conditions that may be imposed.

Management does not expect that recent events at Enron (as described in Note 7, Subsequent Events, in the Notes to Financial Statements) will affect the proposed purchase of PGE by NW Natural, as described above.

Restructuring

PGE filed a restructuring plan, including associated tariffs, with the OPUC in October 2000. Such plan includes a request for increased revenues as well as rules and rate schedules that will allow the Company to implement direct access to energy suppliers by industrial and commercial customers, as provided for in State Senate Bill 1149 (SB1149), enacted in 1999. Under the plan, residential customers will be able to purchase electricity from a "portfolio" of options that will include a cost-of-service rate, a new renewable resource rate, and a market-based rate.

In accordance with a March 2000 accounting order from the OPUC, PGE is deferring incremental costs of implementing SB1149 for recovery in future electricity rates; at September 30, 2001, such costs totaled approximately $11 million.

In July 2001, Oregon's governor signed into law legislation that delays the implementation of SB1149 from October 1, 2001 until March 1, 2002. PGE supported the delay as mutually beneficial to the Company and its customers, allowing additional time for customer communication, required infrastructure additions, and system testing and integration. Restructuring provisions of SB1149 are separate from PGE's general rate increase, which the Company implemented on October 1, 2001.

Because of the five-month delay and changes in Commission rules, PGE has been directed to file a revised Resource Plan, replacing that filed in November 2000, by May 1, 2002.

General Rate Case

The OPUC issued an order in PGE's general rate case on August 31, 2001. The order provides for approximately $440 million in additional annual revenues, primarily as the result of significant increases in the cost of wholesale power and fuel, and established PGE's return on equity at 10.5%. The order authorizes retail price increases, which became effective October 1, 2001, of approximately 31.6% for residential customers, 37.3% for smaller business customers, and 53.2% for commercial and industrial customers. The rate order includes approval of a power cost adjustment mechanism, addressing the Company's exposure to changes in prices of electricity and natural gas in the wholesale energy market, for the period October 1, 2001 through December 31, 2002 (see "Power Cost Mechanisms" below).

On September 24, 2001, a coalition of interest groups filed two pleadings with the OPUC, one requesting a delay in implementing the Company's rate increase and the other requesting reconsideration of the OPUC's order. On September 28, 2001, the OPUC issued an order that denied the request to delay the October 1, 2001 implementation of new rate schedules. The Company expects the OPUC to review the request for reconsideration and issue an order granting or denying the request by November 23, 2001.

Management believes it is unlikely that any material change to the rate order will result from the petition for reconsideration.

Power Cost Mechanisms

As PGE's generation and long-term power purchase contracts provide only a portion of its customers' load, the Company has relied increasingly upon short-term wholesale power purchase contracts and wholesale spot market purchases. To assure supply and reliability to its retail customers, PGE buys and sells power in a wholesale market in which prices have become increasingly volatile. In order to protect both the Company and its customers from such volatility, the OPUC has authorized PGE to defer, for future rate making treatment, actual net variable power costs which differ from certain baseline amounts approved by the Commission. The initial power cost mechanism was effective for the nine-month period ending September 30, 2001; this was replaced with a mechanism covering the period from October 1, 2001 through December 31, 2002.

January 1, 2001 - September 30, 2001

In February 2001, the OPUC authorized PGE to defer net variable power costs which differ from a pre-determined baseline amount of $176 million. Under the mechanism, PGE shares with its retail customers power costs outside of this range for the period January through September 2001. PGE expects to recover one-half (50%) of retail power costs that deviate from the baseline by more than $35 million, up to $56 million, and 90% of retail power costs that deviate from the baseline by more than $56 million.

During the nine-month period, PGE's net variable power costs, as calculated under terms approved by the OPUC, exceeded the year-to-date baseline amount. Approximately $90 million (including $3 million interest) of accrued revenues is included within regulatory assets on the balance sheet. In a subsequent proceeding, PGE will request the recovery of the deferred amount from customers, with any amount to be collected subject to review by the Commission.

October 1, 2001 - December 31, 2002

The OPUC's August 31, 2001 general rate order includes approval of a Power Cost Adjustment mechanism extending through the end of 2002. Under this mechanism, PGE shares with its retail customers the difference between actual net variable power costs and a pre-determined base used to establish base energy rates. In addition, PGE shares with customers the difference between actual energy revenues and a pre-determined base. A portion of the net difference between pre-determined levels and actual net variable power costs and revenues (termed "Power Cost Variance") is subject to recovery (or refund).

Any Power Cost Variance exceeding $28 million is shared with PGE customers, with any variance between $28 million and $38 million shared equally. Of the next $62 million (up to $100 million), PGE will collect or refund 85% of the variance, and of the next $100 million (up to $200 million), PGE will collect or refund 90% of the variance. For variances that exceed $200 million, PGE will collect or refund 95% of the variance.

The Company will maintain a Power Cost Adjustment Account to record both the calculated Power Cost Variance and amounts actually collected from or refunded to customers. Tariff rate adjustments will be revised on a quarterly basis and are subject to review and approval by the OPUC.

Refunds on Wholesale Transactions

The FERC has issued an order directing certain electricity suppliers, including PGE, to supply information regarding wholesale power sales to California made in 2000 and 2001. Settlement discussions have taken place between such power suppliers, the state of California, and the FERC regarding potential refunds by suppliers. Such discussions did not resolve the issues and the FERC has now scheduled formal hearings to determine any potential refunds for sales in the California spot market between October 2, 2000 and June 20, 2001.

FERC hearings were held to determine whether there may have been unjust and unreasonable charges for spot market sales of electricity in the Pacific Northwest by PGE and other suppliers from December 25, 2000 through June 20, 2001. A FERC Administrative Law Judge issued a recommended order that claims for refunds be dismissed. That recommendation, which would eliminate any potential refunds to be paid or received by PGE as a result of this proceeding, is now before the FERC for action.

See Note 5, Refunds on Wholesale Transactions, in the Notes to Financial Statements for further information.

Wholesale Price Mitigation

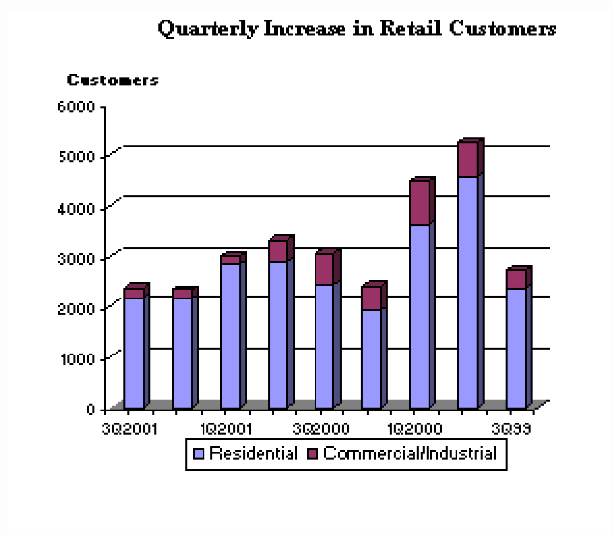
On June 19, 2001, the FERC adopted a price mitigation program for the power system serving 11 Western states, adopting a new benchmark formula that limits prices for spot power transactions at all times throughout the region through September 30, 2002. It applies to power generators, marketers, and investor-owned utilities under FERC jurisdiction, as well as public power providers, municipal utilities, and electric cooperatives that use FERC-regulated transmission lines.

Under the program, a ceiling price is set for wholesale electricity sold in the spot market coordinated by the California Independent System Operator; such price will also apply to markets in the other Western states. The ceiling price, reflecting specified fuel, operations, and maintenance costs, will be based upon the bid submitted by the highest cost gas-fired generating unit whose power is needed when reserves in California fall below 7 percent, triggering a Stage I supply emergency. No bid to sell power may exceed the clearing price as long as the reserve emergency is in place. When reserves again exceed 7 percent, removing the emergency, the ceiling price will drop to 85 percent of the highest hourly price in effect during the most recent Stage 1 reserve emergency. Because of increased credit risk, wholesale electricity sales to California are allowed a 10 percent surcharge.

On July 19, 2001, PGE filed with the FERC a formal request for a rehearing on its price mitigation program, in response to its potentially adverse consequences for citizens, utilities, power marketers, and generators in the Northwest. Such requested rehearing would address the FERC's methodology for the calculation of price mitigation controls instituted in its June 19, 2001 order. It also requests further consideration of the differences between the Northwest and California power markets, including differences in hydropower utilization and seasons of peak usage, in an effort to develop solutions that are both more fair and more likely to achieve reliable power supplies. A technical conference was held at the FERC on October 29, 2001, in which oral testimony was presented on behalf of PGE, with a rehearing currently anticipated by the end of November 2001.

Retail Customer Growth and Energy Sales

Weather adjusted retail energy sales decreased by 3.1% for the nine months ended September 30, 2001, compared to the same period last year. The decrease is attributable to declining state-wide economic activity and to the effect of the Demand Buyback program, in which PGE pays large customers to reduce their load during peak demand periods. In addition, approximately 7,150 retail customers were transferred to two public utility districts in the third quarter of 2000, pursuant to the sale of a portion of PGE's service territory. Manufacturing sector energy sales decreased 5.1% due primarily to the effect of the Demand Buyback program. Excluding the effect of this program, manufacturing sector sales were flat and total retail sales decreased about 1.5%. While commercial sales were flat, sales to residential customers decreased 3.7% in the first nine months of the year due primarily to conservation. PGE expects weather-adjusted retail energy sales to continue to decline in the remainde r of 2001. (The accompanying graph excludes the effect of the transfer of customers pursuant to the sale of a portion of PGE's service territory).



Residential Exchange Program

On October 31, 2000, PGE and BPA signed a Settlement Agreement providing for BPA payments totaling $2.7 million in the third quarter of 2001, with residential customer benefits continued through the end of this period. The Agreement further provides for additional residential exchange benefits, in the form of both cash payments and energy, over a ten-year period beginning October 1, 2001, with benefits, currently estimated at approximately $55 million annually, continuing to pass directly to residential and small farm customers.

Power Supply

Hydro conditions in the region are substantially below normal this year. Volumetric water supply measurements for the Pacific Northwest, prepared by the Northwest River Forecast Center in conjunction with the Natural Resources Conservation Service and other cooperating agencies, indicate the January-to-July runoff at 54.9% of normal, compared to 92% of normal last year.

PGE generated 38% of its total load requirement in the first nine months of 2001, with hydro generation comprising 6% of the total requirement; short- and long-term purchases were utilized to meet the remaining load. The Company's ability to purchase power in the wholesale market, along with its 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. However, surplus generation has diminished in recent years due to economic and population growth in the western United States; in addition, uncertainty over restructuring deregulation has discouraged construction of new generating plants.

Higher prices for natural gas, weather conditions in California and the Southwest, a reduction in surplus generation, and fish protection spill requirements affecting hydro generation, have increased both price and demand pressure on available resources during the past year. Recent changes however, have resulted in significantly lower market prices for both natural gas and electricity; these include additional generation from both new plants and from those returning to service, moderating weather conditions, additional gas supplies, and federal price mitigation.

A new 24.5 megawatt combustion turbine plant, to be operated during peak demand periods, has been constructed at the site of the Company's Beaver plant and became operational on August 3, 2001. In addition, the Company on February 27, 2001 filed a "Notice of Intent" with the Energy Facility Siting Council to build a new 650 megawatt gas turbine plant at the Beaver site. The required site certificate application and air contamination discharge permit are in the process of completion by the Company.

PGE supplements its current power supply capability through the use of forward contracts for the purchase of electricity, expanded energy efficiency programs, a Demand Buyback program which pays large customers to reduce load during peak demand periods, and increased public information activities related to conservation. In addition, the Company continues to make improvements and upgrades to increase the capacity of its generating plants and also participates in wind power and biogas projects to augment its current power supply resources and capability.

Financial Risk Management

PGE's primary business is to serve its retail customers. The Company uses both long- and short-term purchased power contracts to supplement its thermal and hydroelectric generation to respond to seasonal fluctuations in the demand for electricity. 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, options, and futures contracts to mitigate risk that arises from market fluctuations of commodity prices.

Gains and losses from instruments that reduce commodity price risk are recognized in purchased power and fuel expense, or in wholesale revenue (see Note 3, Price Risk Management, in the Notes to Financial Statements for further information).

The use of derivative commodity instruments may expose the Company to market risks arising from adverse changes in commodity prices and the ability of counterparties to meet their commitments to PGE. The Company actively manages these risks to ensure compliance with its risk management policies.

In 2000 and in the first nine months of 2001, PGE's market risk profile has been impacted by increased volatility in electricity and natural gas prices. However, due to continuing low trading limits and volumes, the Company has maintained a limited exposure to market movements. The Company is subject to limits on open commodity positions and monitors this using a value at risk methodology, which measures the potential impact of market movements over a given time interval. Value at risk remains at an immaterial level at September 30, 2001.

In addition, PGE is exposed to risk resulting from changes in interest rates as a result of its issuance of variable rate commercial paper. Although the Company currently has no financial instruments to mitigate such risks, it will consider such instruments in the future, as necessary.

RTO West and Independent Transmission Company

In April 2001, PGE and five other regional utilities received conditional approval from the FERC to form TransConnect, an independent transmission company that will participate in RTO West, a regional non-profit transmission organization that would operate the transmission system in the Pacific Northwest, Nevada, and parts of neighboring states. Pursuant to such approval, TransConnect can initially own or lease the high voltage transmission facilities currently held by its participants.

Five of the original six TransConnect participants plan to file a preliminary tariff with the FERC in November 2001. RTO West currently plans a compliance filing in December 2001 that responds to FERC requests regarding a framework and timetable for formation of a West-wide RTO, among other issues. This will be followed by a March 1, 2002 filing that will provide further details on items such as congestion management, pricing, planning, and systems integration issues. Decisions related to the formation of

RTO West and TransConnect will continue to be subject to approvals by state and federal regulatory agencies and individual company boards of directors.

New Accounting Standards

In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 142, "Goodwill and Other Intangible Assets". SFAS No. 142, which must be applied in fiscal years beginning after December 15, 2001, modifies the accounting and reporting of goodwill and other intangible assets. Although PGE has no goodwill, it has other intangible assets, consisting primarily of software development costs, which are currently being amortized over their estimated useful lives. Under SFAS No. 142, entities are required to determine the useful life of other intangible assets and amortize them over this period. If the useful life is determined to be indefinite, no amortization is to be recorded. For intangible assets recognized prior to the adoption of SFAS No. 142, the useful life is to be reassessed. PGE is currently evaluating the application of SFAS No. 142 pertaining to other intangible assets.

In August 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations". SFAS No. 143, which must be applied in fiscal years beginning after June 15, 2002, requires the recognition, as an Asset Retirement Obligation (ARO), of a liability for dismantlement and restoration costs associated with the retirement of tangible long-lived assets in the period in which the liability is incurred. Upon initial recognition, the probability weighted future cash flows for the associated retirement costs, discounted using a credit-adjusted risk-free rate, are recognized as both a liability and as an increase in the capitalized carrying amount of the related long-lived assets. Capitalized asset retirement costs are depreciated over the life of the related asset, with accretion of the ARO liability classified as an operating expense on the income statement. PGE is currently evaluating the application of SFAS No. 143 to its tangible long-lived assets, substantially all of which are i ncluded in rate-regulated operations, and has not completed the quantification of the impact of the statement.

In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets". SFAS No. 144, which supercedes SFAS No. 121, must be applied in fiscal years beginning after December 15, 2001. SFAS No. 144 retains the fundamental provisions of SFAS No. 121 for the measurement and recognition of the impairment of long-lived assets other than goodwill to be held and used, as well as the measurement of long-lived assets to be disposed of by sale. SFAS No. 144 resolves significant implementation issues related to SFAS No. 121, broadens the component of an entity to be included in the presentation for discontinued operations, and measures long-lived assets held for sale at the lower of their carrying amount or fair value (less cost to sell), while ceasing depreciation. SFAS No. 144 also retains the amendments in SFAS No. 121 pertaining to regulatory assets under SFAS No. 71 and SFAS No. 90. PGE is currently evaluating the application of SFAS No. 144 to its l ong-lived and regulatory assets.

Information Regarding Forward Looking Statements

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Although PGE believes that its expectations are based on reasonable assumptions, it can give no assurance that its expectations will be achieved. Important factors that could cause actual results to differ materially from those in the forward-looking statements herein include, but are not limited to, political developments affecting federal and state regulatory agencies, the pace of electric industry deregulation in Oregon and in the United States, environmental regulations, changes in the cost of power and natural gas, and adverse weather conditions during the periods covered by the forward-looking statements.

PART II

Portland General Electric Company and Subsidiaries

Other Information

Item 1. Legal Proceedings

For further information, see PGE's report on Form 10-K for the year ended December 31, 2000.

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, Marion County Oregon Circuit Court, the Court of Appeals of the State of Oregon, the Oregon Supreme Court.

To provide the OPUC time to consider the issues raised on the URP's complaint challenging PGE's application for approval of the accounting and ratemaking elements of the Trojan settlement, PGE has requested, and the Oregon Supreme Court has granted, an extension from April 16, 2001 until December 2001 for the Court's consideration of the dismissal, as moot, of the cases.

Item 6. Exhibits and Reports on Form 8-K

a. Exhibits

None.

b. Reports on Form 8-K

October 25, 2001 - Item 5. Other Events.

Results of Operations for Third Quarter 2001 and 2000, General Rate Case and Other Regulatory Matters, and Proposed Acquisition

SIGNATURES

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 hereunto duly authorized.

PORTLAND GENERAL ELECTRIC COMPANY

(Registrant)

November 13, 2001	By:	/s/ James J. Piro
		James J. Piro
		Senior Vice President
		Chief Financial Officer and Treasurer

November 13, 2001	By:	/s/ Kirk M. Stevens
		Kirk M. Stevens
		Controller and Assistant Treasurer