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 March 31, 2006

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	Exact name of registrant as specified in its charter, state of incorporation, address of principal executive offices, telephone number	I.R.S. Employer Identification Number
1-16305	**PUGET ENERGY, INC.** A Washington Corporation 10885 NE 4th Street, Suite 1200 Bellevue, Washington 98004-5591 (425) 454-6363	91-1969407
1-4393	**PUGET SOUND ENERGY, INC.** A Washington Corporation 10885 NE 4th Street, Suite 1200 Bellevue, Washington 98004-5591 (425) 454-6363	91-0374630

Indicate by check mark whether the registrants: (1) have 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 registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.

Puget Energy, Inc. Yes /X/ No / / Puget Sound Energy, Inc. Yes /X/ No / /

Indicate by check mark whether 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.

Puget Energy, Inc.	Large accelerated filer	/X/	Accelerated filer	/ /	Non-accelerated filer	/ /
Puget Sound Energy, Inc.	Large accelerated filer	/ /	Accelerated filer	/ /	Non-accelerated filer	/X/

Indicate by check mark whether the registrant is a shell company (as defined in Exchange Act Rule 12b-2)
Puget Energy, Inc. Yes / / No /X/ Puget Sound Energy, Inc. Yes / / No /X/

As of April 25, 2006, (i) the number of shares of Puget Energy, Inc. common stock outstanding was 116,030,932 ($.01 par value) and (ii) all of the outstanding shares of Puget Sound Energy, Inc. common stock were held by Puget Energy, Inc.

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DEFINITIONS

AFUDC	Allowance for Funds Used During Construction
CAISO	California Independent System Operator
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	Financial Accounting Standards Board Interpretation
FPA	Federal Power Act
InfrastruX	InfrastruX Group, Inc.
kWh	Kilowatt Hour
LIBOR	London Interbank Offered Rate
MW	Megawatt (one MW equals one thousand kW)
MWh	Megawatt Hour (one MWh equals one thousand kWh)
PCA	Power Cost Adjustment
PCORC	Power Cost Only Rate Case
PGA	Purchased Gas Adjustment
PSE	Puget Sound Energy, Inc.
Puget Energy	Puget Energy, Inc.
SFAS	Statement of Financial Accounting Standards
Washington Commission	Washington Utilities and Transportation Commission

FILING FORMAT

This Quarterly Report on Form 10-Q is a combined quarterly report filed separately by two different registrants, Puget Energy, Inc. (Puget Energy) and Puget Sound Energy, Inc. (PSE). Any references in this report to the "Company" are to Puget Energy and PSE collectively. PSE makes no representation as to the information contained in this report relating to Puget Energy and the subsidiaries of Puget Energy other than PSE and its subsidiaries.

FORWARD-LOOKING STATEMENTS

Puget Energy and Puget Sound Energy (PSE) are including the following cautionary statements in this Form 10-Q to make applicable and to take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by or on behalf of Puget Energy or PSE. This report includes forward-looking statements, which are statements of expectations, beliefs, plans, objectives, assumptions of future events or performance. Words or phrases such as “anticipates,” “believes,” “estimates,” “expects,” “future,” “intends,” “plans,” “predicts,” “projects,” “will likely result,” “will continue” or similar expressions identify forward-looking statements.

Forward-looking statements involve risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed. Puget Energy’s and PSE’s expectations, beliefs and projections are expressed in good faith and are believed by Puget Energy and PSE, as applicable, 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 Puget Energy’s and PSE’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 Puget Energy and PSE to differ materially from those discussed in forward-looking statements include:

- Governmental policies and regulatory actions, including those of the Federal Energy Regulatory Commission (FERC) and the Washington Utilities and Transportation Commission (Washington Commission), with respect to allowed rates of return, cost recovery, industry and rate structures, transmission and generation business structures within PSE, acquisition and disposal of assets and facilities, operation, maintenance and construction of electric generating facilities, operation of distribution and transmission facilities (gas and electric), licensing of hydroelectric operations and gas storage facilities, recovery of other capital investments, recovery of power and gas costs, recovery of regulatory assets and present or prospective wholesale and retail competition;
- Natural disasters, such as hurricanes, which can cause temporary supply disruptions and/or price spikes in the cost of fuel and raw materials;
- Commodity price risks associated with procuring natural gas and power in wholesale markets that impact customer loads;
- Wholesale market disruption, which may result in a deterioration of market liquidity, increase the risk of counterparty default, affect the regulatory and legislative process in unpredictable ways, negatively affect wholesale energy prices and/or impede PSE’s ability to manage its energy portfolio risks and procure energy supply, affect the availability and access to capital and credit markets and/or impact delivery of energy to PSE from its suppliers;
- The effect of wholesale market structures (including, but not limited to, regional market designs or transmission organizations) or other related federal initiatives;
- PSE electric or gas distribution system failure, which may impact PSE’s ability to deliver energy supply to its customers;
- Weather, which can have a potentially serious impact on PSE’s revenues and/or impact its ability to procure adequate supplies of gas, fuel or purchased power to serve its customers and on the cost of procuring such supplies;
- Variable hydroelectric conditions, which can impact streamflow and PSE’s ability to generate electricity from hydroelectric facilities;
- Plant outages, which can have an adverse impact on PSE’s expenses with respect to repair costs, added costs to replace energy or higher costs associated with dispatching a more expensive resource;
- The ability of gas or electric plant to operate as intended;
- The ability to renew contracts for electric and gas supply and the price of renewal;
- Blackouts or large curtailments of transmission systems, whether PSE’s or others’, which can affect PSE’s ability to deliver load to its customers;
- The ability to restart generation following a regional transmission disruption;
- Failure of the interstate gas pipeline delivering to PSE’s system, which may impact PSE’s ability to adequately deliver gas supply to its customers;
- The amount of collection, if any, of PSE’s receivables from the CAISO and other parties and the amount of refunds found to be due from PSE to the CAISO or other parties;
- Industrial, commercial and residential growth and demographic patterns in the service territories of PSE;
- General economic conditions in the Pacific Northwest, which might impact customer consumption or affect PSE’s accounts receivable;
- The loss of significant customers or changes in the business of significant customers, which may result in changes in demand for PSE’s services;
- The impact of acts of terrorism, flu pandemic or similar significant events;
- Capital market conditions, including changes in the availability of capital or interest rate fluctuations;

- The impacts of natural disasters such as earthquakes, hurricanes, floods, fires or landslides;
- Employee workforce factors, including strikes, work stoppages, availability of qualified employees or the loss of a key executive;
- The ability to obtain adequate insurance coverage and the cost of such insurance; and
- The ability to maintain effective internal controls over financial reporting.

Any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by law, Puget Energy and PSE undertake 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. You are also advised to consult Item 1A-"Risk Factors" in our most recent annual report on Form 10-K.

PART I FINANCIAL INFORMATION

Item 1. **Financial Statements**

PUGET ENERGY, INC.
CONSOLIDATED STATEMENTS OF INCOME
(Dollars in thousands except per share amounts)
(Unaudited)

	THREE MONTHS ENDED MARCH 31, 2006	2005
Operating Revenues:		
Electric	$ 467,424	$ 420,090
Gas	406,588	321,129
Other	3,723	434
Total operating revenues	877,735	741,653
Operating Expenses:		
Energy costs:		
Purchased electricity	252,125	208,178
Electric generation fuel	21,584	20,448
Residential exchange	(56,633)	(55,046)
Purchased gas	266,679	201,744
Net unrealized loss on derivative instruments	975	509
Utility operations and maintenance	87,364	75,522
Other operations and maintenance	855	741
Depreciation and amortization	63,884	58,077
Conservation amortization	8,048	5,162
Taxes other than income taxes	79,732	69,700
Income taxes	40,345	46,084
Total operating expenses	764,958	631,119
Operating income	112,777	110,534
Other income (deductions):		
Other income, net of tax	2,339	1,164
Interest charges:		
AFUDC	2,022	1,462
Interest expense	(43,542)	(41,044)
Mandatorily redeemable securities interest expense	(23)	(23)
Income from continuing operations	73,573	72,093
Income (loss) from discontinued segment (net of tax)	18,947	(1,018)
Net income before cumulative effect of accounting change	92,520	71,075
Cumulative effect of implementation of accounting change (net of tax)	(89)	--
Net income	$ 92,609	$ 71,075
Common shares outstanding weighted average (in thousands)	115,725	99,953
Diluted shares outstanding weighted average (in thousands)	116,190	100,446
Basic earnings per common share before cumulative effect from accounting change	$ 0.64	$ 0.72
Basic earnings per common share from discontinued operations	0.16	(0.01)
Cumulative effect from accounting change	--	--
Basic earnings per common share	$ 0.80	$ 0.71
Diluted earnings per common share before cumulative effect from accounting change	$ 0.63	$ 0.72
Diluted earnings per common share from discontinued operations	0.16	(0.01)
Cumulative effect from accounting change	--	--
Diluted earnings per common share	$ 0.79	$ 0.71

The accompanying notes are an integral part of the financial statements.

PUGET ENERGY, INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Dollars in thousands)
(Unaudited)

	THREE MONTHS ENDED MARCH 31,	
	2006	2005
Net income	$ 92,609	$ 71,075
Other comprehensive income, net of tax at 35%:		
Foreign currency translation adjustment	(17)	3
Net unrealized (losses) gains on derivative instruments during the period	(5,281)	15,658
Reversal of net unrealized gains on derivative instruments settled during the period	(7,607)	(1,817)
Amortization of cash flow hedge contracts to earnings	191	--
Deferral of cash flow hedges related to power cost adjustment mechanism	5,557	(5,563)
Other comprehensive income (loss)	(7,157)	8,281
Comprehensive income	$ 85,452	$ 79,356

The accompanying notes are an integral part of the financial statements.

PUGET ENERGY, INC.
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)
(Unaudited)

ASSETS

	MARCH 31, 2006	DECEMBER 31, 2005
Utility Plant: (at original cost, including construction work in progress of $228,557 and $216,513, respectively)		
Electric	$ 4,842,555	$ 4,802,363
Gas	2,013,902	1,991,456
Common plant	444,421	439,599
Less: Accumulated depreciation and amortization	(2,632,990)	(2,602,500)
Net utility plant	4,667,888	4,630,918
Other property and investments	156,230	157,321
Current assets:		
Cash	17,873	16,710
Restricted cash	1,048	1,047
Accounts receivable, net of allowance for doubtful accounts	299,279	294,509
Secured pledged accounts receivable	24,000	41,000
Unbilled revenues	120,037	160,207
Purchased gas adjustment receivable	72,414	67,335
Materials and supplies, at average cost	37,028	36,491
Fuel and gas inventory, at average cost	45,973	91,058
Unrealized gain on derivative instruments	32,475	75,037
Prepayments and other	9,723	7,596
Current assets of discontinued operations	108,535	107,434
Total current assets	768,385	898,424
Other long-term assets:		
Regulatory asset for deferred income taxes	125,431	129,693
Regulatory asset for PURPA contract buyout costs	185,363	191,170
Unrealized gain on derivative instruments	20,190	28,464
Power cost adjustment mechanism	25,879	18,380
Other	517,888	388,468
Long-term assets of discontinued operations	178,794	167,113
Total other long-term assets	1,053,545	923,288
Total assets	$ 6,646,048	$ 6,609,951

The accompanying notes are an integral part of the financial statements.

PUGET ENERGY, INC.
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)
(Unaudited)

CAPITALIZATION AND LIABILITIES

	MARCH 31, 2006	DECEMBER 31, 2005
Capitalization:		
Common shareholders' investment:		
Common stock $0.01 par value, 250,000,000 shares authorized, 116,055,501 and 115,695,463 shares outstanding, respectively	$ 1,160	$ 1,157
Additional paid-in capital	1,957,294	1,948,975
Earnings reinvested in the business	133,090	69,407
Accumulated other comprehensive income, net of tax at 35%	351	7,508
Total shareholders' equity	2,091,895	2,027,047
Redeemable securities and long-term debt:		
Preferred stock subject to mandatory redemption	1,889	1,889
Junior subordinated debentures of the corporation payable to a subsidiary trust holding mandatorily redeemable preferred securities	237,750	237,750
Long-term debt	2,083,360	2,183,360
Total redeemable securities and long-term debt	2,322,999	2,422,999
Total capitalization	4,414,894	4,450,046
Minority interest in discontinued operations	7,141	6,816
Current liabilities:		
Accounts payable	339,179	346,490
Short-term debt	25,600	41,000
Current maturities of long-term debt	181,000	81,000
Accrued expenses:		
Taxes	134,599	112,860
Salaries and wages	12,796	15,034
Interest	46,473	31,004
Unrealized loss on derivative instruments	33,476	9,772
Deferred income taxes	5,902	10,968
Other	45,261	35,694
Current liabilities of discontinued operations	58,222	55,791
Total current liabilities	882,508	739,613
Long-term liabilities:		
Deferred income taxes	724,619	738,809
Other deferred credits	455,822	513,023
Long-term liabilities of discontinued operations	161,064	161,644
Total long-term liabilities	1,341,505	1,413,476
Total capitalization and liabilities	$ 6,646,048	$ 6,609,951

The accompanying notes are an integral part of the financial statements.

PUGET ENERGY, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in thousands)
(Unaudited)

	THREE MONTHS ENDED MARCH 31,	
	2006	2005
Operating activities:		
Net income	$ 92,609	$ 71,075
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	63,884	60,074
Deferred income taxes and tax credits, net	(11,267)	6,075
Net unrealized loss on derivative instruments	975	509
Accrual of contract initiation payment	(89,000)	--
InfrastruX impairment adjustment	(7,269)	--
Power cost adjustment mechanism	(7,499)	(15,020)
Cash collateral received from (returned to) energy suppliers	(14,850)	3,100
Decrease in residential exchange program	(12,746)	(11,159)
Other	(268)	12,091
Change in certain current assets and liabilities:		
Accounts receivable and unbilled revenue	51,861	(97,786)
Materials and supplies	(122)	(751)
Fuel and gas inventory	45,085	11,453
Prepayments and other	(5,231)	(8,656)
Purchased gas adjustment receivable	(5,079)	(3,242)
Accounts payable	(4,913)	(23,352)
Taxes payable	23,055	31,720
Tenaska disallowance reserve	--	(3,156)
Accrued expenses and other	19,175	12,679
Net cash provided by operating activities	138,400	45,654
Investing activities:		
Construction and capital expenditures-excluding equity AFUDC	(105,389)	(124,376)
Energy efficiency expenditures	(6,884)	(4,738)
Refundable cash received for customer construction projects	2,554	3,582
Restricted cash	(1)	486
Other	6,255	5,515
Net cash used by investing activities	(103,465)	(119,531)
Financing activities:		
Change in short-term debt, net	(13,157)	100,035
Dividends paid	(25,929)	(21,924)
Issuance of common stock	1,788	1,017
Issuance of bonds and notes	1,264	--
Redemption of bonds and notes	--	(2,946)
Issuance costs of bonds and other	137	(737)
Net cash provided (used) by financing activities	(35,897)	75,445
Net increase (decrease) in cash	(962)	1,568
Cash at beginning of year	22,897	19,771
Cash at end of period	$ 21,935	$ 21,339
Supplemental cash flow information:		
Cash payments for:		
Interest (net of capitalized interest)	$ 30,823	$ 32,511
Income taxes	30,000	22,000

The accompanying notes are an integral part of the financial statements.

PUGET SOUND ENERGY, INC.
CONSOLIDATED STATEMENTS OF INCOME
(Dollars in thousands)
(Unaudited)

	THREE MONTHS ENDED MARCH 31, 2006	THREE MONTHS ENDED MARCH 31, 2005
Operating revenues:		
Electric	$ 467,424	$ 420,090
Gas	406,588	321,129
Other	3,723	434
Total operating revenues	877,735	741,653
Operating expenses:		
Energy costs:		
Purchased electricity	252,125	208,178
Electric generation fuel	21,584	20,448
Residential exchange	(56,633)	(55,046)
Purchased gas	266,679	201,744
Net unrealized loss on derivative instruments	975	509
Utility operations and maintenance	87,364	75,522
Other operations and maintenance	320	259
Depreciation and amortization	63,884	58,077
Conservation amortization	8,048	5,162
Taxes other than income taxes	79,732	69,700
Income taxes	40,703	46,545
Total operating expenses	764,781	631,098
Operating income	112,954	110,555
Other income (deductions):		
Other income, net of tax	2,339	1,164
Interest charges:		
AFUDC	2,022	1,462
Interest expense	(43,542)	(40,976)
Mandatorily redeemable securities interest expense	(23)	(23)
Net income before cumulative effect of accounting change	$ 73,750	$ 72,182
Cumulative effect of implementation of accounting change (net of tax)	(89)	--
Net income	$ 73,839	$ 72,182

The accompanying notes are an integral part of the financial statements.

PUGET SOUND ENERGY, INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Dollars in thousands)
(Unaudited)

	THREE MONTHS ENDED MARCH 31,	
	2006	2005
Net income	$ 73,839	$ 72,182
Other comprehensive income, net of tax at 35%:		
Net unrealized (losses) gains on derivative instruments during the period	(5,281)	15,658
Reversal of net unrealized gains on derivative instruments settled during the period	(7,607)	(1,817)
Amortization of cash flow hedge contracts to earnings	191	--
Deferral of cash flow hedges related to power cost adjustment mechanism	5,557	(5,563)
Other comprehensive income (loss)	(7,140)	8,278
Comprehensive income	$ 66,699	$ 80,460

The accompanying notes are an integral part of the financial statements.

PUGET SOUND ENERGY, INC.
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)
(Unaudited)

ASSETS

	MARCH 31, 2006	DECEMBER 31, 2005
Utility plant: (at original cost, including construction work in progress of $228,557 and $216,513, respectively)		
Electric	$ 4,842,555	$ 4,802,363
Gas	2,013,902	1,991,456
Common plant	444,421	439,599
Less: Accumulated depreciation and amortization	(2,632,990)	(2,602,500)
Net utility plant	4,667,888	4,630,918
Other property and investments	156,230	157,321
Current assets:		
Cash	17,872	16,709
Restricted cash	1,048	1,047
Accounts receivable, net of allowance for doubtful accounts	300,021	299,938
Secured pledged accounts receivable	24,000	41,000
Unbilled revenues	120,037	160,207
Purchased gas adjustment receivable	72,414	67,335
Materials and supplies, at average cost	37,028	36,491
Fuel and gas inventory, at average cost	45,973	91,058
Unrealized gain on derivative instruments	32,475	75,037
Prepayments and other	9,150	7,023
Total current assets	660,018	795,845
Other long-term assets:		
Regulatory asset for deferred income taxes	125,431	129,693
Regulatory asset for PURPA contract buyout costs	185,363	191,170
Unrealized gain on derivative instruments	20,190	28,464
Power cost adjustment mechanism	25,879	18,380
Other	517,489	388,009
Total other long-term assets	874,352	755,716
Total assets	$ 6,358,488	$ 6,339,800

The accompanying notes are an integral part of the financial statements.

PUGET SOUND ENERGY, INC.
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)
(Unaudited)

CAPITALIZATION AND LIABILITIES

	MARCH 31, 2006	DECEMBER 31, 2005
Capitalization:		
Common shareholder's investment:		
Common stock ($10 stated value) - 150,000,000 shares authorized, 85,903,791 shares outstanding	$ 859,038	$ 859,038
Additional paid-in capital	928,676	924,154
Earnings reinvested in the business	238,731	196,248
Accumulated other comprehensive income, net of tax at 35%	41	7,181
Total shareholder's equity	2,026,486	1,986,621
Redeemable securities and long-term debt:		
Preferred stock subject to mandatory redemption	1,889	1,889
Junior subordinated debentures of the corporation payable to a subsidiary trust holding mandatorily redeemable preferred securities	237,750	237,750
Long-term debt	2,083,360	2,183,360
Total redeemable securities and long-term debt	2,322,999	2,422,999
Total capitalization	4,349,485	4,409,620
Current liabilities:		
Accounts payable	339,179	346,490
Short-term debt	25,600	41,000
Current maturities of long-term debt	181,000	81,000
Accrued expenses:		
Taxes	133,915	111,900
Salaries and wages	12,796	15,034
Interest	46,473	31,004
Unrealized loss on derivative instruments	33,476	9,772
Deferred income taxes	5,902	10,968
Other	39,942	30,932
Total current liabilities	818,283	678,100
Long-term liabilities:		
Deferred income taxes	735,021	739,162
Other deferred credits	455,699	512,918
Total long-term liabilities	1,190,720	1,252,080
Total capitalization and liabilities	$6,358,488	$6,339,800

The accompanying notes are an integral part of the financial statements.

PUGET SOUND ENERGY, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in thousands)
(Unaudited)

	THREE MONTHS ENDED MARCH 31, 2006	2005
Operating activities:		
Net income	$ 73,839	$ 72,182
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	63,884	58,077
Deferred income taxes and tax credits, net	(1,101)	5,735
Net unrealized loss on derivative instruments	975	509
Accrual of contract initiation payment	(89,000)	--
Power cost adjustment mechanism	(7,499)	(15,020)
Cash collateral received from (returned to) energy suppliers	(14,850)	3,100
Decrease in residential exchange program	(12,746)	(11,159)
Other	639	10,394
Change in certain current assets and liabilities:		
Accounts receivable and unbilled revenue	57,085	(102,060)
Materials and supplies	(537)	(1,106)
Fuel and gas inventory	45,085	11,453
Prepayments and other	(2,128)	(4,962)
Purchased gas adjustment receivable	(5,079)	(3,243)
Accounts payable	(7,310)	(23,865)
Taxes payable	22,016	32,843
Tenaska disallowance reserve	--	(3,156)
Accrued expenses and other	22,242	10,263
Net cash provided by operating activities	145,515	39,985
Investing activities:		
Construction expenditures - excluding equity AFUDC	(101,268)	(117,931)
Energy efficiency expenditures	(6,884)	(4,738)
Refundable cash received for customer construction projects	2,554	3,582
Restricted cash	(1)	487
Other	6,273	5,514
Net cash used by investing activities	(99,326)	(113,086)
Financing activities:		
Change in short-term debt, net	(15,400)	97,051
Dividends paid	(31,356)	(23,053)
Investment from Puget Energy	1,569	--
Issuance cost of bonds and other	161	132
Net cash provided (used) by financing activities	(45,026)	74,130
Net increase in cash	1,163	1,029
Cash at beginning of year	16,709	12,955
Cash at end of period	$ 17,872	$ 13,984
Supplemental cash flow information:		
Cash payments for:		
Interest (net of capitalized interest)	$ 28,394	$ 30,549
Income taxes	30,000	22,000

The accompanying notes are an integral part of the financial statements.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Consolidation Policy

BASIS OF PRESENTATION

Puget Energy is a holding company that owns Puget Sound Energy (PSE) and a 90.9% ownership interest in InfrastruX Group, Inc. (InfrastruX). PSE is a public utility incorporated in the State of Washington and furnishes electric and gas services in a territory covering 6,000 square miles, primarily in the Puget Sound region. InfrastruX is a non-regulated utility construction service company incorporated in the State of Washington, which provides construction services to the electric and gas utility industries primarily in the Midwest, Texas, south-central and eastern United States regions.

The consolidated financial statements of Puget Energy include the accounts of Puget Energy and its subsidiaries, PSE and InfrastruX. Puget Energy holds all the common shares of PSE and until May 2006 owned a 90.9% interest in InfrastruX. The results of PSE and InfrastruX are presented on a consolidated basis. The financial position and results of operations for InfrastruX are presented as discontinued operations. PSE's consolidated financial statements include the accounts of PSE and its subsidiaries. Puget Energy and PSE are collectively referred to herein as "the Company." The consolidated financial statements are presented after elimination of all significant intercompany items and transactions. Certain amounts previously reported have been reclassified to conform with current year presentations with no effect on total equity or net income.

The consolidated financial statements contained in this Form 10-Q are unaudited. In the respective opinions of the management of Puget Energy and PSE, all adjustments necessary for a fair statement of the results for the interim periods have been reflected and were of a normal recurring nature. These condensed financial statements should be read in conjunction with the audited financial statements (and the Combined Notes thereto) included in the combined Puget Energy and PSE annual report on Form 10-K for the year ended December 31, 2005. With the treatment of InfrastruX as discontinued operations, Puget Energy now only has one reportable segment.

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

(2) Discontinued Operations (Puget Energy Only)

Following a strategic review of InfrastruX that was completed in February 2005, Puget Energy's Board of Directors decided to exit the utility construction services sector. Puget Energy believes the planned disposal of InfrastruX meets the criteria established for recognition as a discontinued operation under SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," and is accounted for as such in Puget Energy's consolidated financial statements in 2005 and 2006. In May 2006, Puget Energy entered into a sale agreement with an affiliate of Tenaska Power Fund L.P. to sell InfrastruX. The total purchase price was $275 million. After repayment of debt, adjustments for working capital, transaction costs and distributions to minority interests, Puget Energy expects to receive after-tax cash proceeds of approximately $83 million to $88 million for its 90.9% interest in InfrastruX. The sale is expected to result in an after-tax gain of approximately $24 million to $29 million to Puget Energy in the second quarter of 2006.

For the three months ended March 31, 2006, Puget Energy reported InfrastruX related income from discontinued operations (net of taxes and minority interest) of $18.9 million compared to a loss of $1.0 million (net of taxes and minority interest) for the three months ended March 31, 2005. Puget Energy's income from discontinued operations for the three months ended March 31, 2006 includes $7.3 million related to the reversal of a carrying value adjustment recorded in 2005 as well as $10 million related to the anticipated realization of a deferred tax asset associated with the sale of the business in accordance with EITF No. 93-17, "Recognition of Deferred Tax Assets for a Parent Company's Excess Tax Basis in the Stock of a Subsidiary That is accounted for as a Discontinued Operation." In accordance with SFAS No. 144, Puget Energy discontinued depreciation and amortization of InfrastruX's assets effective February 8, 2005.

The following table summarizes Puget Energy's income from discontinued operations:

THREE MONTHS ENDED MARCH 31,

(DOLLARS IN THOUSANDS)	2006	2005
Net loss reported by InfrastruX	$ (331)	$ (1,496)
InfrastruX depreciation and amortization not recorded by Puget Energy, net of tax	3,071	1,597
Puget Energy tax benefit (valuation allowance) from goodwill deduction	174	--
Puget Energy carrying value adjustment of InfrastruX	7,269	--
Puget Energy cost of sale related to InfrastruX, net of tax	(937)	(1,116)
Puget Energy deferred tax basis adjustment of InfrastruX	9,966	--
Minority interest in income from discontinued operations	(265)	(3)
Income (loss) from discontinued operations	$ 18,947	$ (1,018)

InfrastruX's bank and vendor debt under its credit agreements totaled $133.8 million at March 31, 2006 compared to $130.3 million at December 31, 2005 and $159.4 million at March 31, 2005. In May 2004, InfrastruX signed a three-year agreement with a group of banks to provide up to $150 million in financing, with Puget Energy as guarantor. Certain InfrastruX subsidiaries also have borrowing capacities for working capital purposes of which Puget Energy is not the guarantor. Of the $150 million bank facility available to InfrastruX, $112 million was outstanding at March 31, 2006 and December 31, 2005. In determining the fair value of its InfrastruX investment, Puget Energy has determined proceeds of a sale will first be used to extinguish all outstanding InfrastruX debt.

The expected net proceeds from a proposed sale of InfrastruX exceed its carrying value at March 31, 2006. In accordance with SFAS No. 144, Puget Energy has reversed the previously recorded SFAS No. 144 impairment charge to adjust the investment in InfrastruX to the lower of its carrying value without the impairment, less cost to sell, or fair value. After reflecting the adjustment, tax-basis adjustment and related transaction costs of $12.4 million in 2005, Puget Energy's equity investment in InfrastruX was $52.9 million at March 31, 2006 compared to $43.5 million at December 31, 2005. The following amounts related to InfrastruX have been segregated from continuing operations and reflected as discontinued operations:

THREE MONTHS ENDED, MARCH 31, (DOLLARS IN THOUSANDS)	2006	2005
Revenues	$ 92,070	$ 77,692
Operating expenses (including interest expense)	87,823	77,716
Carrying value adjustment	(7,269)	--
Cost of sale	937	1,717
Pre-tax income	10,579	(1,741)
Income tax benefit	8,633	726
Minority interest in income of discontinued operations	(265)	(3)
Income (loss) from discontinued operations	$ 18,947	$ (1,018)

In accordance with SFAS No. 144, InfrastruX discontinued depreciation and amortization of its assets effective February 8, 2005. This discontinuation of depreciation and amortization resulted in $4.8 million ($3.1 million after-tax) and $2.6 million ($0.9 million after-tax) lower depreciation and amortization expense than otherwise would have been recorded as continuing operations for the three months ended March 31, 2006 and 2005, respectively.

InfrastruX's summarized balance sheets, including intercompany balances eliminated in consolidation, are as follows:

(DOLLARS IN THOUSANDS)	MARCH 31, 2006	DECEMBER 31, 2005
Assets:		
Cash	$ 4,061	$ 6,187
Accounts receivable	79,379	78,842
Other current assets	25,095	22,405
Total current assets	108,535	107,434
Goodwill	43,886	43,886
Intangibles	13,924	14,443
Non-utility property and other	120,984	108,784
Total long-term assets	178,794	167,113
Total assets	$ 287,329	$ 274,547
Liabilities:		
Accounts payable	$ 11,575	$ 9,178
Short-term debt	6,052	3,809
Current maturities of long-term debt	6,576	6,477
Other current liabilities	34,019	36,327
Total current liabilities	58,222	55,791
Deferred income taxes	24,527	24,645
Long-term debt	121,178	120,013
Other deferred credits	15,359	16,986
Total long-term liabilities	161,064	161,644
Total liabilities	$ 219,286	$ 217,435

(3) Earnings per Common Share (Puget Energy Only)

Puget Energy's basic earnings per common share have been computed based on weighted average common shares outstanding of 115,725,000 for the three months ended March 31, 2006, and 99,953,000 for the three months ended March 31, 2005.

Puget Energy's diluted earnings per common share have been computed based on weighted average common shares outstanding of 116,190,000 for the three months ended March 30, 2006, and 100,446,000 for the three months ended March 31, 2005. These shares include the dilutive effect of securities related to employee and director equity plans.

(4) Accounting for Derivative Instruments and Hedging Activities

SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138 and SFAS No. 149, requires that all contracts considered to be derivative instruments be recorded on the balance sheet at their fair value. The Company enters into both physical and financial contracts to manage its energy resource portfolio and interest rate exposure including forward physical and financial contracts, option contracts and swaps. The majority of these contracts qualify for the normal purchase normal sale (NPNS) exception to derivative accounting rules, if they meet certain criteria. NPNS applies if the counterparty is creditworthy and has energy resources within the western region to allow for physical delivery of the energy, and if the transaction is within PSE's forecasted load requirements. Those contracts that do not meet NPNS exception or cash flow hedge criteria are marked-to-market to current earnings in the income statement, subject to deferral under SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," for energy related derivatives due to the Power Cost Adjustment (PCA) mechanism and Purchased Gas Adjustment (PGA) Mechanism.

The nature of serving regulated electric customers with its wholesale portfolio of owned and contracted electric generation resources exposes the Company and its customers to some volumetric and commodity price risks within the sharing mechanism of the PCA. The Company's energy risk portfolio management function monitors and manages these risks using analytical models and tools. The Company is not engaged in the business of assuming risk for the purpose of realizing speculative trading revenues. Therefore, wholesale market transactions are focused on balancing the Company's energy portfolio, reducing costs and risks where feasible, and reducing volatility in wholesale costs and margin in the portfolio. In order to manage risks effectively, the Company enters into physical and financial transactions, which are appropriate for the service territory of the Company and are relevant to its regulated electric and gas portfolios.

The Company's energy portfolio management staff develops hedging strategies for the Company's energy supply portfolio. The first priority is to obtain reliable supply for delivery to the Company's retail customers. The second priority is to protect against unwanted risk exposure. The third priority is to optimize excess capacity or flexibility within the energy portfolio.

At March 31, 2006, the Company was subject to a range of netting provisions, including both stand alone agreements and the provisions associated with the Western Systems Power Pool agreement of which many energy suppliers in the western United States are a part.

During the three months ended March 31, 2006, the Company recorded a decrease in earnings for the change in the market value of derivative instruments not meeting NPNS nor cash flow hedge criteria of approximately $1.0 million compared to a decrease in earnings of approximately $0.5 million for the three months ended March 31, 2005. At March 31, 2006, the Company had a net unrealized gain recorded in other comprehensive income of $29.6 million after-tax related to energy and financial contracts which meet the criteria for designation as cash flow hedges under SFAS No. 133. In 2006, a portion of the total unrealized gain on cash flow hedge transactions in other comprehensive income and the marked-to-market loss in the income statement were deferred in accordance with SFAS No. 71 due to the Company exceeding the $40 million cap under the PCA mechanism. At March 31, 2006, PSE had a net short-term asset of $14.6 million on non-cash flow hedges and a long-term asset of $20.2 million related to energy contracts designated as cash flow hedges that represent forward financial purchases of gas supply for electric generation from PSE-owned electric plants in future periods. If it is determined that it is uneconomical to run the plants in the future period, the hedging relationship is ended and the cash flow hedge is de-designated and any unrealized gains and losses are recorded in the income statement. Gains and losses when these de-designated cash flow hedges are settled are recognized in energy costs and are included as part of the PCA mechanism.

At March 31, 2006, the Company also has a net short-term liability of approximately $25.2 million related to the cash flow hedge of gas contracts to serve natural gas customers. All mark-to-market adjustments relating to the natural gas business have been reclassified to a deferred account in accordance with SFAS No. 71 due to the PGA mechanism. The PGA mechanism passes increases and decreases in the cost of natural gas supply to customers. As the gains and losses on the cash flow hedges are realized in future periods, they will be recorded as gas costs under the PGA mechanism.

In the second quarter 2005, the Company entered into two forward starting interest rate swap contracts to hedge against interest rate volatility for a debt offering anticipated to be performed in the second half of 2006. A forward starting swap is a financial arrangement between the Company and a counterparty whereby one of the parties will be required to make a payment to the other party on a specific valuation date based upon the change in value of a designated treasury bond. If interest rates rise related to the hedged debt from the date of issuance of the swap instruments, the Company would receive a payment from the counterparty for the change in the bond value. Alternatively, if interest rates decrease related to the hedged debt from the date of issuance of the swap instruments, the Company would pay the counterparty for the change in the bond value. These swap contracts were designated under SFAS No. 133 criteria as cash flow hedges. All financial hedge contracts of this type are reviewed by senior management and presented to the Finance and Budget Committee of the Board of Directors and are approved prior to execution. At March 31, 2006, the unrealized gain associated with the swap contracts was $7.7 million after tax and is included in other comprehensive income. The swap contracts settle in 2006.

(5) Stock Compensation (Puget Energy Only)

Prior to 2006, the Company had various stock-based compensation plans which were accounted for according to Accounting Principles Board (APB) No. 25, "Accounting for Stock Issued to Employees," and related interpretations as allowed by SFAS No. 123, "Accounting for Stock-Based Compensation." In 2003, the Company adopted the fair value based accounting of SFAS No. 123 using the prospective method under the guidance of SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure." The Company applied SFAS No. 123 accounting to stock compensation awards granted subsequent to January 1, 2003, while grants prior to 2003 continued to be accounted for using the intrinsic value method of APB No. 25. Effective January 1, 2006, the Company adopted the fair value recognition provisions of SFAS No.

123R, "Share-Based Payment," using the modified-prospective transition method. Under that transition method, compensation cost recognized in 2006 includes: (a) compensation cost for all share-based payments granted prior to, but not yet vested as of January 1, 2006, based on the grant date fair value estimated in accordance with the original provisions of SFAS No. 123, and (b) compensation cost for all share-based payments granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS No. 123R. Results for prior periods have not been restated, as provided for under the modified-prospective method.

The adoption of SFAS 123R resulted in a cumulative benefit from an accounting change amounting to $0.1 million, net of tax, for the quarter ended March 31, 2006. The cumulative effect adjustment is primarily the result of the inclusion of estimated forfeitures occurring before award vesting dates in the computation of compensation expense for unvested awards for which compensation expense was previously recognized.

As a result of adopting SFAS No. 123R on January 1, 2006, the Company's income before income taxes and net income from continuing operations for the quarter ended March 31, 2006, are $0.1 million and $0.1 million higher, respectively, than if it had continued to account for share-based compensation under SFAS No. 123. Basic and diluted earnings per share for income from continuing operations for the quarter ended March 31, 2006, would have been $0.80 and $0.79, respectively, if the Company had not adopted SFAS No. 123R, compared to basic and diluted earnings per share of $0.80 and $0.79, respectively.

Had the Company applied the fair value method of accounting specified by SFAS No. 123 for all grants at their grant date rather than prospectively implementing SFAS No. 123, net income and earnings per share would have been as follows:

THREE MONTHS ENDED MARCH 31, (DOLLARS IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)	2005
Net income, as reported	$ 71,075
Add: Total stock-based employee compensation expense included in net income, net of tax	636
Less: Total stock-based employee compensation expense per the fair value method of SFAS No. 123, net of tax	(810)
Pro forma net income	$ 70,901
Earnings per share:	
Basic per common share as reported	$ 0.71
Diluted per common share as reported	$ 0.71
Basic per common share pro forma	$ 0.71
Diluted per common share pro forma	$ 0.71

The Company's Long-Term Incentive Plan (LTI Plan), established in 1995, encompasses many of the awards granted to employees. The plan was amended and restated in 2005, and approved by shareholders. The LTI Plan applies to officers and key employees of the Company and awards granted under this plan include stock awards, performance awards or other stock-based awards as defined by the plan. Any shares awarded are either purchased on the open market or are a new issuance. The 2006 cycle included a grant of restricted stock, which was added to reduce the volatility of the plan. Beginning with the 2004 share grants, plan participants meeting the Company's stock ownership guidelines can elect to be paid up to 50% of the share award in cash. The maximum number of shares that may be purchased or issued as new shares for the LTI Plan is 4,200,000.

PERFORMANCE SHARE GRANTS

The Company generally awards performance share grants annually under the LTI Plan. These are granted to key employees and vest at the end of three years for grants made in 2004, 2005 and 2006. Grants made prior to 2004 vest in four years. The number of shares awarded and expense recorded, depends on Puget Energy's performance as compared to other companies and service quality indices for customer service. Compensation expense related to performance share grants was $(0.6) million and $0.8 million for the quarters ended March 31, 2006 and 2005, respectively. The weighted average fair value per share of the performance awards granted for the 2006, 2005, 2004 and 2003 cycles was $21.18, $21.19, $19.70, and $16.93, respectively. There were a total of 151,815 performance awards granted for the 2006 cycle of which the company estimates a forfeiture rate of 10.1%, or 15,333 awards based on historical forfeitures. There were a total of 251,680 performance awards granted for the 2005 cycle of which the Company estimated a forfeiture rate of 11.8%, or 29,698, awards based on historical forfeitures. As of March 31, 2006, there were four active grant cycles for a total of 863,394 grants outstanding. As of December 31, 2005, there were four active grant cycles for a total of 907,983 share grants outstanding. As of March 31, 2006, there was $3.8 million of total unrecognized compensation cost, net of forfeitures, related to nonvested performance share grants. That cost is expected to be recognized over a weighted-average period of 2.25 years. During the quarter ended March 31, 2006, 42,892 performance shares were forfeited. No performance shares vested during the quarters ended March 31, 2006 and 2005. The fair value of the 2006 performance share grants takes into consideration the historical performance of the performance share grants and prospective analysis using the Capital Asset Pricing Model and expected EPS growth rates. Shares granted prior to 2006 were valued using the Black-Scholes option pricing model.

MEASUREMENT OF PERFORMANCE SHARE GRANTS

The portion of the performance share grants that can be paid in cash are classified and accounted for as liabilities under SFAS No. 123R. As a result, the expense recognized over the performance period for a portion of the performance share grants will equal the fair value (i.e. cash value) of the award as of the last day of the performance period times the number of awards that are earned. Furthermore, SFAS No. 123R requires the quarterly expense recognized during the performance period to be based on the fair value of the performance share grants as of the end of the most recent quarter. Prior to the end of the performance period, compensation costs for the liability portion of performance share grants are based on the awards' most recent quarterly fair values and the number of months of service rendered during the performance period. The fair value of the performance share grants is based on the closing price of the Company's common stock on the date of measurement.

STOCK OPTIONS

In 2002, Puget Energy's Board of Directors granted 40,000 stock options under the LTI Plan and an additional 260,000 options outside of the LTI Plan (for a total of 300,000 non-qualified stock options) to the Chairman, President and Chief Executive Officer. These options can be exercised at the grant date market price of $22.51 per share and vest annually over four and five years although the options would become fully vested upon a change of control of the Company or an employment termination without cause. The options expire 10 years from the grant date and have a remaining contractual term of approximately 6 years. All 300,000 options remained outstanding at March 31, 2006, with 270,000 options exercisable. There is no aggregate intrinsic value of options vested (or expected to vest) or options currently exercisable at March 31, 2006. At March 31, 2005, 202,500 options were exercisable. The fair value of the options at the grant date was $3.33 per share. Compensation expense related to stock options was $0.02 million for the quarter ended March 31, 2006. As of March 31, 2006, there was $0.1 million of total unrecognized compensation cost related to nonvested stock options which will be recognized in 2006. The total fair value of stock options vested during the quarters ended March 31, 2006 and 2005, was $0.2 million and $0.2 million, respectively. The fair value of the stock option award was estimated on the date of grant using the Black-Scholes option valuation model.

RESTRICTED STOCK

In 2006, 2005, 2004 and 2003 the Company granted 107,181 shares, 50,000 shares, 40,000 shares and 11,000 shares, respectively, of restricted stock under the LTI Plan to be purchased on the open market or as a new issuance. During the quarter ended March 31, 2006, 107,181 shares of restricted stock were granted as part of the 2006 LTIP cycle. The shares vest 15% on January 1, 2007, 25% vest on January 1, 2008, and the remaining 60% vest on January 1, 2009 based upon a performance and service condition. Under the 2005 grant, 40,000 shares vest in one installment on the date of the 2008 Annual Shareholders' Meeting based upon performance criteria and the remaining 10,000 shares vest equally over three years. The 2004 grant vests 8,000 shares in three years and the remaining 32,000 shares in four years. For the 2003 grant, 1,000 vested in 2003 with the remaining shares vesting evenly over the following five years. At March 31, 2006, there were 213,181 total shares of nonvested restricted stock and the weighted average grant date fair value of these shares was $22.01. Compensation expense related to the restricted shares, including the restricted shares granted as part of the 2006 LTIP cycle, was $0.5 million and $0.1 million for the quarter ended March 31, 2006 and 2005, respectively. Dividends are paid on all outstanding shares of restricted stock and are accounted for as a Puget Energy common stock dividend, not as compensation expense. The weighted average grant date fair value for all outstanding shares of restricted stock granted in 2006 and 2005 was $21.32 and $21.86, respectively. As of March 31, 2006, there was $1.7 million of total unrecognized compensation cost related to nonvested restricted stock. That cost is expected to be recognized over a weighted-average period of 2.7 years. No restricted stock vested or was forfeited during the quarters ended March 31, 2006 and 2005. The fair value of the restricted stock is based on the closing price of the Company's common stock on the date of grant.

RESTRICTED STOCK UNITS

The Company also granted 10,000 restricted stock units outside of the LTI Plan but subject to the terms and conditions of the plan. The units vest 2,000 shares in three years and the remaining 8,000 shares in four years. At March 31, 2006, there were 4,216 total shares of nonvested restricted stock units and the weighted average fair value of these units was $21.18. There were no restricted stock units granted or forfeited during the quarter ended March 31, 2006. There were 643 restricted stock units accrued during the quarter ended March 31, 2006. The restricted stock units will be settled in cash when they become vested at the end of each cycle. Dividends are paid on the outstanding stock units and are accounted for as compensation expense. Compensation expense related to the restricted stock units agreement was immaterial for the quarter ended March 31, 2006 and 2005. The weighted average grant date fair value for the restricted stock units was $23.55. As of March 31, 2006, there was $0.1 million of total unrecognized compensation cost related to nonvested restricted stock units. That cost is expected to be recognized over a weighted-average period of 2 years. The fair value of the restricted stock is based on the closing price of the Company's common stock at each reporting period.

RETIREMENT EQUIVALENT STOCK

The Company has a retirement equivalent stock agreement in which in lieu of participating in the Company's executive supplemental retirement plan the Chairman, President and Chief Executive Officer is granted performance-based stock equivalents in January of each year, which are deferred under the Company's deferred compensation plan. In 2006, 2005, 2004 and 2003, the Company awarded 8,218, 6,063, 6,469 and 4,319, shares, respectively, which vest over a period from January 1, 2002 to May 2008 at 15% per year for the first six years and the remaining 10% in the seventh year. At March 31, 2006 there were 7,522 total shares of nonvested retirement equivalent stock units and the weighted average grant date fair value of these units was $22.72. During the quarter ended March 31, 2006, 8,218 retirement equivalent stock units were granted. Dividends are paid on the stock equivalents accumulated in the deferred compensation account in the form of Puget Energy common stock, which is added to the deferred compensation account. Compensation expense related to the retirement equivalent stock agreement was $0.1 million and $0.1 million for the quarter ended March 31, 2006 and 2005, respectively. The weighted average grant date fair value for the retirement equivalent stock was $20.42, $24.70, $23.77 and $22.05 for 2006, 2005, 2004 and 2003, respectively. As of March 31, 2006, there was $0.2 million of total unrecognized compensation cost related to nonvested retirement equivalent stock units. That cost is expected to be recognized over a weighted-average period of 2.17 years. There were 5,709 retirement equivalent stock units that vested during the quarter ended March 31, 2006. No retirement equivalent stock units were forfeited during the quarter ended March 31, 2006. The fair value of the restricted stock is based on the closing price of the Company's common stock on the date of grant.

EMPLOYEE STOCK PURCHASE PLAN

The Company has a shareholder-approved Employee Stock Purchase Plan (ESPP) open to all employees. Offerings occur at six-month intervals at the end of which the participating employees receive shares for 85% of the lower of the stock's fair market price at the beginning or the end of the six-month period. A maximum of 500,000 shares may be sold to employees under the plan through May 2007. At December 31, 2005, 148,814 shares could still be sold to employees under the plan. Under the SFAS No. 123 accounting that the Company adopted in 2003 and under SFAS No. 123R, ESPP is considered to be compensation expense and the amount is immaterial to the financial statements. As of March 31, 2006, 32,609 purchase rights had been granted. Dividends are not paid on ESPP shares until they are purchased by employees and thus are accounted for as dividends, not compensation expense. No purchase rights vested or were forfeited for the quarter ended March 31, 2006 and 2005, respectively.

NON-EMPLOYEE DIRECTOR STOCK PLAN

The Company has a director stock plan approved in 1997 and effective beginning in 1998, for all non-employee directors of Puget Energy and PSE. The plan was amended and restated in 2005 and approved by shareholders in 2005. Under the plan, which has a term through December 31, 2015, non-employee directors receive a portion of their quarterly retainer fees in Puget Energy stock except that 100% of quarterly retainers are paid in Puget Energy stock until the director holds a number of shares equal in value to two years of their retainer fees. Directors may optionally receive their entire retainer in Puget Energy stock. The compensation expense related to the director stock plan was $0.1 million for the quarter ended March 31, 2006 and 2005, respectively. The Company issues new shares or purchases stock for this plan on the open market up to a maximum of 350,000 shares. As of March 31, 2006, 30,617 shares had been issued or purchased for the director stock plan and 78,650 deferred, for a total of 109,268 shares. As of March 31, 2005, the number of shares that had been purchased for the director stock plan was 19,095 and 66,866 deferred, for a total of 85,961 shares.

OPTION MODEL ASSUMPTIONS

The Company used the Black-Scholes option pricing model to determine the fair value of certain stock-based awards to employees. The following assumptions were used for awards outstanding in 2006 and 2005.

STOCK ISSUANCE CYCLE	2006	2005	2004	2003	2002
Stock options					
Risk-free interest rate	*	*	*	*	4.32%
Expected lives – years	*	*	*	*	5.0
Expected stock volatility	*	*	*	*	22.82%
Dividend yield	*	*	*	*	5.00%
Performance awards					
Risk-free interest rate	*	2.50%	2.59%	2.35%	*
Expected lives – years	3.0	3.0	3.0	4.0	*
Expected stock volatility	*	15.10%	22.24%	23.85%	*
Dividend yield	*	4.18%	4.45%	4.86%	*
Employee Stock Purchase Plan					
Risk-free interest rate	4.07%	2.68%	1.28%	1.07%	*
Expected lives – years	0.5	0.5	0.5	0.5	*
Expected stock volatility	13.03%	13.98%	9.89%	19.47%	*
Dividend yield	4.77%	4.17%	4.42%	4.39%	*

** Not applicable*

The expected lives of the securities represents the estimated period of time until exercise and is based on the vesting period of the award and the historical exercise experience of similar awards. All participants were assumed to have similar exercise behavior. Expected volatility is based on historical volatility over the approximate expected term of the option.

(6) Retirement Benefits

The following summarizes the net periodic benefit cost for the three months ended March 31:

	PENSION BENEFITS		OTHER BENEFITS	
(DOLLARS IN THOUSANDS)	2006	2005	2006	2005
Service cost	$ 3,061	$ 3,014	$ 86	$ 84
Interest cost	6,167	5,949	358	419
Expected return on plan assets	(9,434)	(9,514)	(182)	(219)
Amortization of prior service cost	585	717	134	116
Recognized net actuarial (gain) loss	1,253	767	(127)	(24)
Amortization of transition (asset) obligation	--	(41)	105	105
Net periodic benefit cost	$ 1,632	$ 892	$ 374	$ 481

The Company previously disclosed in its financial statements for the year ended December 31, 2005 that it expected contributions by the Company to fund the pension and other benefits plans for the year ended December 31, 2006 to be $2.1 million and $1.0 million, respectively. During the three months ended March 31, 2006, the actual cash contributions to the pension plans were $0.5 million. Based on this activity, the Company anticipates contributing an additional $1.6 million to the Company's pension plan in 2006. The full amount of the pension plan funding for 2006 is for the Company's non-qualified supplemental retirement plan.

During the three months ended March 31, 2006, actual other post-retirement medical benefit plan contributions were $0.4 million, and the Company expects to make additional contributions of $0.3 million for a total of $0.7 in 2006.

On March 31, 2006, FASB issued a Proposed Statement of Financial Accounting Standard titled “Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans.” The proposed statement would require the Company to report the overfunded or underfunded status of defined benefit postretirement plans in the Company’s consolidated balance sheet. An overfunded status would result in the recognition of an asset and an underfunded status would result in the recognition of a liability. This amount is to be measured as the difference between the fair value of plan assets and the benefit obligation. At December 31, 2005, the combined fair value of plan assets and benefit obligation for the Company’s defined benefit pension and the retiree medical and life plans were $481 million and $439 million, respectively. Any adjustment required to recognize an asset or liability upon adoption of the standard, as currently proposed, would result in a charge or benefit to Accumulated Other Comprehensive Income. The Company is currently evaluating what impact the application of the proposed standard will have on its operations. FASB indicated that it expects to issue a final statement by September 2006 and that the statement would be effective for fiscal years ending after December 15, 2006, which will be the year ended December 31, 2006, for the Company.

(7) Regulatory and Other

PSE has contracted to purchase a portion of the output from the Rocky Reach and Rock Island hydroelectric generating facilities located on the mid-Columbia River owned by Chelan County PUD (Chelan). On February 3, 2006, PSE and Chelan entered into a new Power Sales Agreement and a related Transmission Agreement for 25% of the output of the Rocky Reach and Rock Island facilities in exchange for PSE paying 25% of the operating costs of the facilities. PSE's share of the output represents approximately 487 MW of capacity and 243 average MW of energy. The agreements terminate in 2031 and provide that PSE will begin to receive power upon expiration of PSE’s existing long-term contracts with Chelan for the Rocky Reach and Rock Island output (expiring in 2011 and 2012, respectively). FERC granted approval of the agreement on March 28, 2006, and PSE made a non-refundable capacity reservation payment of $89 million on April 26, 2006, to Chelan under the terms of the agreement. PSE believes that the new agreements with Chelan will lower its overall power costs during the 20-year contract period compared to other available alternatives, secure critical operational flexibility, reduce PSE’s projected long-term energy and capacity deficit and continue PSE’s long-term relationship with the public utility district. PSE filed for an accounting order from the Washington Commission in April 2006 for approval to recognize such payments as a regulatory asset with accrual of interest at the Company’s net of tax rate of return. On April 26, 2006 the Washington Commission approved the accounting petition to defer the capacity reserve payment plus interest on a temporary basis until resolution of PSE’s electric general rate case later this year.

At March 31, 2006, PSE had a net receivable totaling $21.2 million in connection with wholesale sales in 2000 to the California Independent System Operator (CAISO) and counterparties where payment to PSE was conditioned on the counterparties being paid by the California Power Exchange. In August 2005, PSE submitted a Fuel Cost Adjustment Claim for $3.4 million related to sales in 2000 to the CAISO, pursuant to FERC’s California refund proceeding.

Pursuant to an order issued by FERC in August 2005, PSE also submitted a Portfolio Cost Claim in September 2005 for $9.3 million to the CAISO. On January 26, 2006, FERC issued its order on Cost Filings accepting PSE’s cost filing subject to certain modifications, which appear to have the effect of reducing PSE’s Portfolio Claim substantially. However, the Company does not believe the claim will be reduced below the $21.2 million receivable. PSE does not agree with all of FERC’s rulings and sought rehearing. PSE’s ability to recover all or a portion of these claims is uncertain at the present time.

Based upon FERC orders, PSE has determined a range related to its CAISO receivable to be between $21.2 million (PSE’s net receivable balance) and $28.0 million, including interest, on its past due receivables as of March 31, 2006.

In January 2003, the Financial Accounting Standards Board (FASB) issued Interpretation No. 46R, “Consolidation of Variable Interest Entities” (FIN 46R). FIN 46R requires that if a business entity has a controlling financial interest in a variable interest entity, the financial statements of the variable interest entity must be included in the consolidated financial statements of the business entity. The Company has evaluated its purchase power agreements and determined that three counterparties may be considered variable interest entities. Consistent with FIN 46R, PSE submitted requests for information to those parties; however, the parties have refused to submit to PSE the necessary information for PSE to determine whether they meet the requirements of a variable interest entity. PSE also determined that it does not have a contractual right to such information. PSE will continue to submit requests for information to the counterparties on a quarterly basis in accordance with FIN 46R.

For the three purchase power agreements that may be considered variable interest entities under FIN 46R, PSE is required to buy all the generation from these plants, subject to displacement by PSE, at rates set forth in the purchase power agreements. If at any time the counterparties cannot deliver energy to PSE, PSE would have to buy energy in the wholesale market at prices which could be higher or lower than the purchase power agreement prices. PSE's purchased electricity expense for the three months ended March 31, 2006 and 2005 for these three entities was $58.8 million and $71.8 million, respectively

(8) Litigation

There are several actions in the U.S. Ninth Circuit Court of Appeals against Bonneville Power Administration (BPA), in which the petitioners assert or may assert that BPA acted contrary to law or without authority in deciding to enter into, or in entering into or performing or implementing, a number of contracts, including the amended settlement agreement and the May 2004 agreement between BPA and PSE. BPA rates used in such amended settlement agreement between BPA and PSE for determining the amounts of money to be paid to PSE by BPA under the amended settlement agreement and other agreements described above during the period October 1, 2001 through September 30, 2006 have been confirmed, approved and allowed to go into effect by FERC. There are also several actions in the U.S. Ninth Circuit Court of Appeals against BPA, in which petitioners assert that BPA acted contrary to law in adopting or implementing the rates or rate adjustment clause upon which the benefits received or to be received from BPA during the October 1, 2001 through September 30, 2006 period are based. The parties to these various actions presented oral arguments to the U.S. Ninth Circuit Court of Appeals in November 2005. A decision from the Court is anticipated in 2006. It is not clear what impact, if any, review of such rates and contracts and the above described U.S. Ninth Circuit Court of Appeals actions may have on PSE.

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

The following discussion of the Company's financial condition and results of operations contains forward-looking statements that involve risks and uncertainties, such as statements of the Company's plans, objectives, expectations and intentions. Words such as "anticipates," "believes," "estimates," "expects," "future," "intends," "plans," "projects," "predicts," "will likely result," and "will continue" and similar expressions are used to identify forward-looking statements. However, these words are not the exclusive means of identifying such statements. In addition, any statements that refer to expectations, projections or other characterizations of future events or circumstances are forward-looking statements. The Company's actual results could differ materially from those anticipated in these forward-looking statements for many reasons, including the factors described below and under the caption "Forward-Looking Statements" at the beginning of this report. You should not place undue reliance on these forward-looking statements, which apply only as of the date of this Form 10-Q.

Overview

Puget Energy is an energy services holding company and all of its operations are conducted through its two subsidiaries. These subsidiaries are Puget Sound Energy (PSE), a regulated electric and gas utility company, and until May 2006, InfrastruX, a utility construction and services company. Following a strategic review of Puget Energy's unregulated subsidiary, InfrastruX, that was completed in February 2005, Puget Energy's Board of Directors decided to exit the utility construction services sector. InfrastruX is presented in the financial statements as discontinued operations. On April 29, 2006, the board of directors of Puget Energy, Inc. approved the merger of InfrastruX with an affiliate of Tenaska Power Fund L.P. ("Tenaska"), through which Tenaska will acquire InfrastruX and in May 2006, Puget Energy entered into a sale agreement with an affiliate of Tenaska Power Fund L.P. to sell InfrastruX. The total purchase price was $275 million. After repayment of debt, adjustments for working capital, transaction costs and distributions to minority interests, Puget Energy expects to receive after-tax cash proceeds of approximately $83 million to $88 million for its 90.9% interest in InfrastruX. The sale is expected to result in an after-tax gain of approximately $24 million to $29 million to Puget Energy in the second quarter of 2006. See section titled "InfrastruX" for further discussion.

PUGET SOUND ENERGY

PSE generates revenues from the sale of electric and gas services, mainly to residential and commercial customers within Washington State. A majority of PSE's revenues are generated in the first and fourth quarters during the winter heating season in Washington State.

As a regulated utility company, PSE is subject to Federal Energy Regulatory Commission (FERC) and Washington Utilities and Transportation Commission (Washington Commission) regulation which may impact a large array of business activities, including limitation of future rate increases; directed accounting requirements that may negatively impact earnings; licensing of PSE-owned generation facilities; and other FERC and Washington Commission directives that may impact PSE's long-term goals. In addition, PSE is subject to risks inherent to the utility industry as a whole, including weather changes affecting purchases and sales of energy; outages at owned and non-owned generation plants where energy is obtained; storms or other events which can damage electric distribution and transmission lines; and wholesale market stability over time.

PSE's main operational objective is to provide reliable, safe and cost-effective energy to its customers. To help accomplish this objective, PSE intends to be more self-sufficient in energy generation resources. Owning more generation resources will reduce the Company's reliance on the wholesale energy market. PSE is continually exploring for new electric-power resource generation and long-term purchase power agreements to meet this goal. The completion of the Hopkins Ridge wind project in the fourth quarter 2005 and progress on construction of the Wild Horse wind project are two steps in reaching this goal. The Hopkins Ridge wind project provides approximately 150 MW of capacity or 52 average MW. The Company expects to complete construction of the Wild Horse wind project by the end of 2006. The Wild Horse wind project is designed to provide approximately 230 MW of capacity or 73 average MW. Together these electric generation resources will serve the needs of approximately 123,000 of PSE's electric customers.

The Hopkins Ridge wind project and the Wild Horse wind project were included as part of PSE's energy resource portfolio in its long-term electric Least Cost Plan that was filed May 2, 2005 with the Washington Commission. The plan supports a strategy of diverse resource acquisitions including resources fueled by natural gas and coal, renewable resources and shared resources. The Least Cost Plan was followed by issuing an all-source request for proposal (RFP) on November 1, 2005. Proposals were received January 13, 2006 and are currently under evaluation and assessment.

Results of Operations

PUGET ENERGY

All the operations of Puget Energy are conducted through its subsidiaries, PSE and until May 2006, InfrastruX. Net income for the three months ended March 31, 2006 was $92.6 million on operating revenues from continuing operations of $877.7 million compared to net income of $71.1 million on operating revenues from continuing operations of $741.7 million for the same period in 2005. The net income for both periods includes the results of discontinued operations for InfrastruX.

Basic and diluted earnings per share for the three months ended March 31, 2006 was $0.80 and $0.79, respectively, compared to basic and diluted earnings per share for the three months ended March 31, 2005 of $0.71. Included in the basic and diluted earnings per share for the three months ended March 31, 2006 and 2005 was $0.16 and $(0.01), respectively, earnings per share related to discontinued operations of InfrastruX.

Net income for the three months ended March 31, 2006 reflects the reversal of an InfrastruX carrying value charge recognized in 2005 of $7.3 million and a deferred tax benefit on the carrying value and tax basis difference amounting to $10.0 million. The InfrastruX carrying value adjustment and deferred tax benefit contributed to income from discontinued operations of $18.9 million for the three months ended March 31, 2006 compared to a loss of $1.0 million in the same period in 2005. Net income for the three months ended March 31, 2006 was also positively impacted by increased natural gas and electric margins of $12.7 million and $4.4 million, respectively, compared to the same period in 2005 primarily from increased electric and natural gas sales volumes. The increase was offset by higher storm damage repair costs due to severe wind storms in the first quarter 2006, an increase in non-storm related operations and maintenance expense and depreciation expense which negatively impacted net income.

PUGET SOUND ENERGY

PSE's operating revenues and associated expenses are not generated evenly during the year. Variations in energy usage by consumers occur from season to season and from month to month within a season, primarily as a result of weather conditions. PSE normally experiences its highest retail energy sales during the heating season in the first and fourth quarters of the year, and its lowest sales in the third quarter of the year. Varying wholesale electric prices and the amount of hydroelectric energy supplies available to PSE also make quarter-to-quarter comparisons difficult.

ENERGY MARGINS

PSE uses the following margin information in reviewing its operations to determine whether PSE is collecting the appropriate amount of energy costs from its customers to allow recovery of its operating costs.

The following table displays the details of electric margin changes for the three months ended March 31, 2006 compared to the same period in 2005. Electric margin is electric sales to retail and transportation customers less pass-through tariff items and revenue-sensitive taxes, and the cost of generating and purchasing electric energy sold to customers, including transmission costs to bring electric energy to PSE's service territory.

(DOLLARS IN MILLIONS) THREE MONTHS ENDED MARCH 31,	ELECTRIC MARGIN 2006	2005	CHANGE	PERCENT CHANGE
Electric retail sales revenue	$ 435.2	$ 387.0	$ 48.2	12.5 %
Electric transportation revenue	2.7	2.7	--	-- %
Other electric revenue-gas supply resale	5.9	4.2	1.7	40.5 %
Total electric revenue for margin[1]	443.8	393.9	49.9	12.7 %
Adjustments for amounts included in revenue:				
Pass-through production tax credits (PTCs)	3.9	--	3.9	*
Pass-through tariff items	(8.6)	(6.5)	(2.1)	(32.3)%
Pass-through revenue-sensitive taxes	(31.9)	(28.6)	(3.3)	(11.5)%
Residential exchange credit	56.6	55.0	1.6	2.9 %
Net electric revenue for margin	463.8	413.8	50.0	12.1 %
Minus power costs:				
Electric generation fuel	(21.6)	(20.4)	(1.2)	(5.9)%
Purchased electricity, net of sales to other utilities and marketers[2]	(243.5)	(209.8)	(33.7)	(16.1)%
Total electric power costs[3]	(265.1)	(230.2)	(34.9)	(15.2)%
Electric margin before PCA	198.7	183.6	15.1	8.2 %
Tenaska disallowance reserve	--	5.3	(5.3)	*
Power cost deferred under the PCA mechanism	7.2	12.6	(5.4)	(42.9)%
Electric margin[4]	$ 205.9	$ 201.5	$ 4.4	2.2 %

* *Percent change not applicable or unmeaningful.*

1 *For the three months ended March 31, 2006, total electric revenue for margin was $443.8 million, which does not include $15.8 million in sales to other utilities and marketers and $7.8 million in other miscellaneous electric revenue included in electric operating revenues of $467.4 million. For the three months ended March 31, 2005, total electric revenue for margin was $393.9 million, which does not include $16.3 million in sales to other utilities and marketers and $9.8 million in other miscellaneous electric revenues included in electric operating revenues of $420.0 million.*

2 *For the three months ended March 31, 2006, purchased electricity, net of sales to other utilities and marketers, was $243.5 million, excluding sales to other utilities and marketers of $15.8 million and including power cost deferral under the PCA mechanism of $(7.2) million, purchased electricity was $252.1 million. For the three months ended March 31, 2005, purchased electricity, net of sales to other utilities and marketers, was $209.8 million, excluding sales to other utilities and marketers of $16.3 million and including the Tenaska disallowance reserve turnaround of $(5.3) million and power cost deferral under the PCA mechanism of $(12.6) million, purchased electricity was $208.2 million.*

3 *For the three months ended March 31, 2006, total electric power costs were $265.1 million, which includes electric generation fuel and purchased electricity, net of sales to other utilities and marketers (see note 2 above), but does not include the residential exchange credit of $(56.6) million and unrealized net loss on derivative instruments of $1.0 million. These amounts, excluding sales of electricity to other utilities and marketers, provide electric energy costs of $218.1 million. For the three months ended March 31, 2005, total electric power costs were $230.2 million, which includes electric generation fuel and purchased electricity, net of sales to other utilities and marketers (see note 2 above), but does not include the residential exchange credit of $(55.0) million and unrealized net loss on derivative instruments of $0.5 million. These amounts excluding sales of electricity to other utilities and marketers provide electric energy costs of $174.1 million.*

4 *Electric margin does not include any allocation for amortization/depreciation expense or electric generation operations and maintenance expense.*

Electric margin increased $4.4 million for the three months ended March 31, 2006 compared to the same period in 2005, primarily due to increase in retail customer usage and varied usage among customer classes as compared to 2005. Retail customer kWh sales (residential, commercial and industrial customers) increased 4.4% for the three months ended March 31, 2006 compared to 2005. These increases were partially offset by the non-recurring benefit of a February 23, 2005 Washington Commission order allowing recovery of power costs that lowered electric margin by $6.0 million for the three months ended March 31, 2006 compared to the same period in 2005. The electric general rate increase effective March 4, 2005 primarily recovers increases in power costs and thus does not have a material effect on margin.

The following table displays the details of gas margin changes for the three months ended March 31, 2006 compared to the same period in 2005. Gas margin is gas sales to retail and transportation customers less pass-through tariff items and revenue-sensitive taxes, and the cost of gas purchased, including gas transportation costs to bring gas to PSE's service territory.

GAS MARGIN

(DOLLARS IN MILLIONS) THREE MONTHS ENDED MARCH 31,	2006	2005	CHANGE	PERCENT CHANGE
Gas retail revenue	$ 398.7	$ 312.9	$ 85.8	27.4 %
Gas transportation revenue	3.6	3.4	0.2	5.9 %
Total gas revenue for margin[1]	402.3	316.3	86.0	27.2 %
Adjustments for amounts included in revenue:				
Pass-through tariff items	(2.6)	(1.9)	(0.7)	(36.8)%
Pass-through revenue-sensitive taxes	(32.7)	(25.1)	(7.6)	(30.3)%
Net gas revenue for margin	367.0	289.3	77.7	26.9 %
Minus purchased gas costs	(266.7)	(201.7)	(65.0)	(32.2)%
Gas margin[2]	$ 100.3	$ 87.6	$ 12.7	14.5 %

1 *For the three months ended March 31, 2006, total gas revenue for margin was $402.3 million, which does not include $4.3 million related to other gas operating revenues that is included in gas operating revenues of $406.6 million. For the three months ended March 31, 2005, total gas revenue for margin was $316.3 million, which does not include $4.8 million related to other gas operating revenues that is included in gas operating revenues of $321.1 million.*

2 *Gas margin does not include any allocation for amortization/depreciation expense or electric generation operations and maintenance expense.*

Gas margin increased $12.7 million for the three months ended March 31, 2006 compared to the same period in 2005 primarily due to increased gas general tariff rates and increased usage by customers. Gas margin increased $7.0 million as a result of the gas general tariff increase effective March 4, 2005. Therm sales increased 8.5% for the three months ended March 31, 2006 compared to the same period in 2005, which provided $7.4 million to gas margin. Gas margin decreased $1.7 million for the three months ended March 31, 2006 compared to the same period in 2005 as a result of changes in customer class usage.

ELECTRIC OPERATING REVENUES

The table below sets forth changes in electric operating revenues for PSE for the three months ended March 31, 2006 compared to the same period in 2005.

(DOLLARS IN MILLIONS) THREE MONTHS ENDED MARCH 31,	2006	2005	CHANGE	PERCENT CHANGE
Electric operating revenues:				
Residential sales	$ 241.9	$ 211.8	$ 30.1	14.2 %
Commercial sales	182.8	157.9	24.9	15.8 %
Industrial sales	26.3	22.1	4.2	19.0 %
Other retail sales, including unbilled revenue	(15.8)	(4.8)	(11.0)	*
Total retail sales	435.2	387.0	48.2	12.5 %
Transportation sales	2.7	2.7	--	-- %
Sales to other utilities and marketers	15.8	16.3	(0.5)	(3.1)%
Other	13.7	14.0	(0.3)	(2.1)%
Total electric operating revenues	$ 467.4	$ 420.0	$ 47.4	11.3 %

* *Percent change not applicable or meaningful*

Electric retail sales increased $48.2 million for the three months ended March 31, 2006 compared to the same period in 2005 due primarily to rate increases related to the Power Cost Only Rate Case (PCORC), the electric general rate case and increased retail customer usage. The PCORC and electric general rate case provided $21.1 million and $6.4 million to electric operating revenues, respectively, for the three months ended March 31, 2006 compared to the same period in 2005. Retail electricity usage increased 246,635 MWh or 4.4% for the three months ended March 31, 2006 compared to the same period in 2005, which resulted in an approximate $16.8 million increase in electric operating revenue. During the three month period ended March 31, 2006, the benefits of the Residential and Farm Energy Exchange Benefit credited to customers reduced electric operating revenues by $59.3 million compared to $57.6 million for the same period in 2005. This credit also reduced power costs by a corresponding amount with no impact on earnings.

During the three month period ended March 31, 2006, the benefits of production tax credits (PTCs) (federal income tax credits received for wind generation) were passed through to electric customers by crediting customers' bills, which reduced electric operating revenues by $3.9 million. The PTCs also reduced income taxes. The PTCs began November 2005 when the Hopkins Ridge wind generation facility was placed in service.

Sales to other utilities and marketers decreased $0.5 million compared to the three month period ended March 31, 2005 primarily due to a decrease of 25,877 MWh sold related to excess energy available for sale on the wholesale market. The decrease in MWh sold was due to differences in timing of the need for power to serve base load and actual weather conditions. Sales to other utilities and marketers are included in the PCA mechanism as a reduction in determining net power costs.

Other electric revenues decreased $0.3 million for the three months ended March 31, 2006 compared to the same period in 2005, primarily from the reduction of miscellaneous customer revenue and transmission revenue, which reduced other electric revenues by $2.1 million for the three months ended March 31, 2006 compared to the same period in 2005. This decrease was partially offset by an increase in the sale of non-core gas purchased for intended electric generation of $1.8 million during the three months ended March 31, 2006 compared to the same period in 2005. Non-core gas sales are included in the PCA mechanism calculation as a reduction in determining net power costs.

The following electric rate changes were approved by the Washington Commission in 2006 and 2005:

Type of Rate Adjustment	Effective Date	Average Percentage Increase in Rates	Annual Increase in Revenues (Dollars in Millions)
Electric General Rate Case	March 4, 2005	4.1%	$57.7
Power Cost Only Rate Case	November 1, 2005	3.7%	55.6

Gas Operating Revenues

The table below sets forth changes in gas operating revenues for PSE for the three months ended March 31, 2006 compared to the same period in 2005.

(Dollars in Millions) Three Months Ended March 31,	2006	2005	Change	Percent Change
Gas operating revenues:				
Residential sales	$ 265.1	$ 208.7	$ 56.4	27.0 %
Commercial sales	116.8	91.2	25.6	28.1 %
Industrial sales	16.8	13.0	3.8	29.2 %
Total retail sales	398.7	312.9	85.8	27.4 %
Transportation sales	3.6	3.4	0.2	5.9 %
Other	4.3	4.8	(0.5)	(10.4)%
Total gas operating revenues	$ 406.6	$ 321.1	$ 85.5	26.6 %

Gas retail sales increased $85.8 million for the three months ended March 31, 2006 compared to the same period in 2005 due to higher Purchased Gas Adjustment (PGA) mechanism rates in 2006, approval of a 3.5% general gas rate increase in the gas general rate case effective March 4, 2005, and higher customer gas usage. The Washington Commission approved a PGA mechanism rate increase effective October 1, 2005 that increased rates 14.7% annually. The PGA mechanism passes through to customers increases or decreases in the gas supply portion of the natural gas service rates based upon changes in the price of natural gas purchased from producers and wholesale marketers or changes in gas pipeline transportation costs. PSE's gas margin and net income are not affected by changes under the PGA mechanism. For the three months ended March 31, 2006, the effects of the PGA mechanism rate increases provided an increase of $47.9 million in gas operating revenues. In addition, the gas general rate case increased gas rates by 3.5%, which provided an additional $7.0 million in gas operating revenue for the three months ended March 31, 2006 compared to the same period in 2005. An increase of 3.0% in the average number of customers increased customer usage by 28.9 million therms or approximately $29.3 million in gas operating revenues.

The following gas rate adjustments were approved by the Washington Commission in 2006 and 2005:

Type of Rate Adjustment	Effective Date	Average Percentage Increase in Rates	Annual Increase in Revenues (Dollars in Millions)
Gas General Rate Case	March 4, 2005	3.5 %	$ 26.3
Purchased Gas Adjustment	October 1, 2005	14.7 %	121.6

Operating Expenses

The table below sets forth significant changes in operating expenses for PSE and its subsidiaries for the three months ended March 31, 2006 compared to the same period in 2005.

(Dollars in Millions) Three Months Ended March 31,	2006	2005	Change	Percent Change
Purchased electricity	$ 252.1	$ 208.2	$ 43.9	21.1 %
Electric generation fuel	21.6	20.4	1.2	5.9 %
Purchased gas	266.7	201.7	65.0	32.2 %
Utility operations and maintenance	87.4	75.5	11.9	15.8 %
Depreciation and amortization	63.9	58.1	5.8	10.0 %
Conservation amortization	8.0	5.2	2.8	53.8 %
Taxes other than income taxes	79.7	69.7	10.0	14.3 %
Income taxes	40.7	46.5	(5.8)	(12.5)%

Purchased electricity expenses increased $43.9 million for the three months ended March 31, 2006 compared to the same period in 2005. The increase was primarily the result of increased power purchases from higher customer kWh sales and higher wholesale market prices. Total purchased power for the three months ended March 31, 2006 increased 95,182 MWh or 2.0% compared to the same period in 2005. Increases in the purchases and wholesale price of power contributed $29.3 million to the increase. Also contributing to the increase was a February 23, 2005 Washington Commission order concerning PSE's compliance filing related to the PCA 2 period of July 1, 2003 through June 30, 2004. In its order, the Washington Commission determined that PSE was allowed to reflect additional power costs totaling $6.0 million during the PCA 2 period of July 1, 2003 through December 31, 2003 during the three months ended March 31, 2005. These costs were deferred under the PCA mechanism, which resulted in a reduction in purchased electricity expense for the three months ended March 31, 2005. Increase in transmission and other expenses contributed $8.6 million.

PSE's hydroelectric production and related power costs in 2005 was negatively impacted by below-normal precipitation and reduced snow pack in the Pacific Northwest region. PSE cannot determine if lower than normal runoff will continue in future years nor what impact such a trend may have on the amount of electricity that will need to be purchased. The April 20, 2006 Columbia Basin Runoff Forecast published by the National Weather Service Northwest River Forecast Center indicated that the total forecasted runoff above Grand Coulee Reservoir for the period January through July 2006 would be 103% of normal, which compares to 83% of normal observed runoff for the same period in 2005.

To meet customer demand, PSE economically dispatches resources in its power supply portfolio such as fossil-fuel generation, owned and contracted hydroelectric capacity and energy, and long-term contracted power. However, depending principally upon availability of hydroelectric energy, plant availability, fuel prices and/or changing load as a result of weather, PSE may sell surplus power or purchase deficit power in the wholesale market. PSE manages its regulated power portfolio through short-term and intermediate-term off-system physical purchases and sales, and through other risk management techniques.

Electric generation fuel expense increased $1.2 million for the three months ended March 31, 2006, compared to the same period in 2005. The increase is primarily related to an increase in the cost of coal at Colstrip generating facilities of $2.6

million for the three months ended March 31, 2006 compared to the same period in 2005. Offsetting the increase is a decrease in the cost of gas of PSE-controlled combustion turbine generating facilities due to a reduction in generation at the combustion turbine generation facilities.

Purchased gas expenses increased $65.0 million for the three months ended March 31, 2006, compared to the same period in 2005 primarily due to an increase in PGA rates as approved by the Washington Commission and higher customer therm sales. The PGA mechanism allows PSE to recover expected gas costs, and defer, as a receivable or liability, any gas costs that exceed or fall short of this expected gas cost amount in PGA mechanism rates, including accrued interest. The PGA mechanism receivable balance at March 31, 2006 and December 31, 2005 was $ 72.4 million and $67.3 million, respectively. PSE is authorized by the Washington Commission to accrue carrying costs on PGA receivable balances. A receivable balance in the PGA mechanism reflects a current underrecovery of market gas cost through rates.

Utility operations and maintenance expense increased $11.9 million for the three months ended March 31, 2006, compared to the same period in 2005. The increase for the three months ended March 31, 2006 includes higher electric distribution system restoration costs as a result of a series of strong winter storms with high winds in Western Washington during 2006. Storm damage related costs increased $7.1 million compared to the same period in 2005. Operations and maintenance costs at PSE-owned electric generating facilities increased $2.0 million due primarily to the Hopkins Ridge wind generating facility which was placed in service in November 2005. In addition, maintenance of electric and gas distribution system increased $2.7 million for the three months ended March 31, 2006 compared to the same period in 2005. PSE anticipates operation and maintenance expense to increase in future years as investments in new generating resources and energy delivery infrastructure are completed. The timing and amounts of increases will vary depending on when new generating resources come into service.

Depreciation and amortization expense increased $5.8 million for the three months ended March 31, 2006, compared to the same period in 2005 due to additional utility plant placed into service, including $2.0 million related to PSE’s Hopkins Ridge wind project that became operational on November 26, 2005. PSE anticipates depreciation expense will increase in future years as investments in new generating resources and energy delivery infrastructure are completed.

Conservation amortization increased $2.8 million for the three months ended March 31, 2006 compared to the same period in 2005 due to higher authorized recovery of electric conservation expenditures. Conservation amortization is a pass-through tariff item with no impact on earnings.

Taxes other than income taxes increased $10.0 million for the three months ended March 31, 2006, compared to the same period in 2005 due primarily to increases in revenue-based Washington State excise tax and municipal tax due to increased operating revenues. Revenue sensitive Washington State excise and municipal taxes have no impact on earnings. The increase in revenue based excise taxes was partially offset by a reduction of property taxes of $1.7 million for the three months ended March 31, 2006 compared to the same period in 2005.

Income taxes decreased $5.8 million for the three months ended March 31, 2006, compared to the same period in 2005. The decrease was the result of a lower effective tax rate as compared to the same period in 2005. Included in the lower effective tax rates are production tax credits related to energy production from the Hopkins Ridge wind generating facility. The production tax credits are passed through to electric customers through reduction in electric rates.

OTHER INCOME AND INTEREST CHARGES

The table below sets forth significant changes in other income and interest charges for PSE and its subsidiaries for the three months ended March 31, 2006 compared to the same period in 2005.

(DOLLARS IN MILLIONS) THREE MONTHS ENDED MARCH 31,	2006	2005	CHANGE	PERCENT CHANGE
Other income (net of tax)	$ 2.3	$ 1.2	$ 1.1	91.7%
Interest charges	41.5	39.5	2.0	5.1%

Other income increased $1.1 million (after-tax) for the three months ended March 31, 2006 compared to the same period is 2005 primarily due to increases in the equity portion of allowance for funds used during construction and a decrease in long-term incentive plan costs.

Interest charges increased $2.0 million for the three months ended March 31, 2006 compared to the same period in 2005. The increase is due primarily to higher average interest rates and higher amounts of borrowings outstanding during the three months ended March 31, 2006 compared to the same period in 2005.

INFRASTRUX

Following a strategic review of InfrastruX that was completed in February 2005, Puget Energy's Board of Directors decided to exit the utility construction services sector. Puget Energy believes the planned disposal of InfrastruX meets the criteria established for recognition as a discontinued operation under SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," and is accounted for as such in Puget Energy's consolidated financial statements in 2006 and 2005. In May 2006, Puget Energy entered into a sale agreement with Tenaska Power Fund L.P. to sell InfrastruX. The total purchase price was $275 million. After repayment of debt, adjustments for working capital, transaction costs and distributions to minority interests, Puget Energy expects to receive after-tax cash proceeds of approximately $83 million to $88 million for its 90.9% interest in InfrastruX. The sale is expected to result in an after-tax gain of approximately $24 million to $29 million to Puget Energy in the second quarter of 2006.

For the three months ended March 31, 2006, Puget Energy reported InfrastruX related income from discontinued operations (net of taxes and minority interest) of $18.9 million compared to a loss of $1.0 million (net of taxes and minority interest) for the three months ended March 31, 2005. Puget Energy's income from discontinued operations for the three months ended March 31, 2006 includes $7.3 million related to the reversal of a carrying value adjustment recorded in 2005 as well as $10 million related to the anticipated realization of a deferred tax asset associated with the sale of the business in accordance with EITF No. 93-17, "Recognition of Deferred Tax Assets for a Parent Company's Excess Tax Basis in the Stock of a Subsidiary That is accounted for as a Discontinued Operation." In accordance with SFAS No. 144, Puget Energy discontinued depreciation and amortization of InfrastruX's assets effective February 8, 2005.

The following table summarizes Puget Energy's income from discontinued operations:

THREE MONTHS ENDED MARCH 31, (DOLLARS IN THOUSANDS)	2006	2005
Net loss reported by InfrastruX	$ (331)	$ (1,496)
InfrastruX depreciation and amortization not recorded by Puget Energy, net of tax	3,071	1,597
Puget Energy tax benefit (valuation allowance) from goodwill deduction	174	--
Puget Energy carrying value adjustment of InfrastruX	7,269	--
Puget Energy cost of sale related to InfrastruX, net of tax	(937)	(1,116)
Puget Energy deferred tax basis adjustment of InfrastruX	9,966	--
Minority interest in income from discontinued operations	(265)	(3)
Income (loss) from discontinued operations	$ 18,947	$ (1,018)

InfrastruX's operating revenue for the three months ended March 31, 2006 was $92.1 million, compared to $77.7 million, for the same period in 2005. Pre-tax operating income for the three months ended March 31, 2006 was $10.6 million compared to a loss of $1.7 million for the same period in 2005. InfrastruX's bank and vendor debt under its credit agreements totaled $133.8 million at March 31, 2006 compared to $130.3 million at December 31, 2005 and $159.4 million at March 31, 2005. In May 2004, InfrastruX signed a three-year agreement with a group of banks to provide up to $150 million in financing. Under the credit agreement, Puget Energy is the guarantor of the line of credit. Certain InfrastruX subsidiaries also have borrowing capacities for working capital purposes of which Puget Energy is not the guarantor. Of the $150 million bank facility available to InfrastruX, $112 million was outstanding at March 31, 2006 and at December 31, 2005. In determining the fair value of its InfrastruX investment, Puget Energy has determined proceeds on a sale will first be used to extinguish all InfrastruX debt outstanding.

The expected net proceeds from a proposed sale of InfrastruX exceed its carrying value. In accordance with SFAS No. 144, Puget Energy has reversed the previously recorded SFAS No. 144 impairment charge to adjust the investment in InfrastruX to the lower of its carrying value without the impairment, less cost to sell, or fair value. After reflecting the adjustment, tax-basis adjustment and related transaction cost of $12.4 million in 2005, Puget Energy's equity investment in InfrastruX was $52.9 million at March 31, 2006 compared to $43.5 million at December 31, 2005.

CAPITAL REQUIREMENTS

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

Puget Energy and Puget Sound Energy. The following are Puget Energy and Puget Sound Energy's aggregate consolidated contractual and commercial commitments as of March 31, 2006:

PUGET ENERGY AND PUGET SOUND ENERGY CONTRACTUAL OBLIGATIONS (DOLLARS IN MILLIONS)	Total	PAYMENTS DUE PER PERIOD 2006	2007-2008	2009-2010	2011 & Thereafter
Long-term debt including interest	$ 4,021.8	$ 190.6	$ 567.6	$ 606.8	$ 2,656.8
Short-term debt including interest	25.6	25.6	--	--	--
Junior subordinated debentures payable to a subsidiary trust including interest[1]	895.7	15.0	39.8	39.8	801.1
Mandatorily redeemable preferred stock	1.9	--	--	--	1.9
Service contract obligations	156.9	18.3	55.2	54.3	29.1
Non-cancelable operating leases	92.1	9.5	26.6	19.1	36.9
Fredonia combustion turbines lease [2]	59.7	3.3	8.5	8.2	39.7
Energy purchase obligations	6,326.2	717.3	1,856.6	1,280.2	2,472.1
Contract initiation payment/collateral requirement	107.5	89.0	--	--	18.5
Financial hedge obligations	34.8	9.3	25.5	--	--
Purchase obligations	277.5	277.5	--	--	--
Non-qualified pension and other benefits funding	50.0	2.7	11.1	10.2	26.0
Total contractual cash obligations	$ 12,049.7	$ 1,358.1	$ 2,590.9	$ 2,018.6	$ 6,082.1

Puget Energy. The following are Puget Energy's aggregate consolidated (including PSE) commercial commitments as of March 31, 2006:

Puget Energy COMMERCIAL COMMITMENTS (DOLLARS IN MILLIONS)	TOTAL	AMOUNT OF COMMITMENT EXPIRATION PER PERIOD 2006	2007-2008	2009-2010	2011 & THEREAFTER
Guarantees [3]	$ 112.0	$ --	$ 112.0	$ --	$ --
Credit agreement - available [4]	497.9	--	--	--	497.9
Unsecured credit agreement	20.0				20.0
Receivable securitization facility [5]	176.0	--	--	176.0	--
Energy operations letter of credit	0.5	0.5	--	--	--
Total commercial commitments	$ 806.4	$ 0.5	$ 112.0	$ 176.0	$ 517.9

1 *In 1997 and 2001, PSE formed Puget Sound Energy Capital Trust I and Puget Sound Energy Capital Trust II, respectively, for the sole purpose of issuing and selling preferred securities (Trust Securities) to investors and issuing common securities to PSE. The proceeds from the sale of Trust Securities were used by the Trusts to purchase Junior Subordinated Debentures (Debentures) from PSE. The Debentures are the sole assets of the Trusts and PSE owns all common securities of the Trusts.*

2 *See "Fredonia 3 and 4 Operating Lease" under "Off-Balance Sheet Arrangements" below.*

3 *In May 2004, InfrastruX signed a three-year credit agreement with a group of banks to provide up to $150 million in financing. Under the credit agreement, Puget Energy is the guarantor of the line of credit. Certain InfrastruX subsidiaries also have certain borrowing capacities for working capital purposes of which Puget Energy is not a guarantor. Of the $150 million available to InfrastruX, $112.0 was outstanding March 31, 2006.*

4 *At March 31, 2006, PSE had available a $500 million unsecured credit agreement expiring in April 2011. The credit agreement provides credit support for letters of credit and commercial paper. At March 31, 2006, PSE had $0.5 million for an outstanding letter of credit and $1.6 million commercial paper outstanding, thereby effectively reducing the available borrowing capacity to $497.9 million.*

5 *At March 31, 2006, PSE had available a $200 million receivables securitization facility that expires in December 2010. At March 31, 2006, PSE had $24.0 million outstanding under its receivables securitization program, thereby effectively reduced the available borrowing capacity to $176.0 million. See "Receivables Securitization Facility" below for further discussion.*

Puget Sound Energy. The following are PSE's aggregate commercial commitments as of March 31, 2006:

Puget Sound Energy COMMERCIAL COMMITMENTS (DOLLARS IN MILLIONS)	Total	AMOUNT OF COMMITMENT EXPIRATION PER PERIOD 2006	2007-2008	2009-2010	2011 & Thereafter
Credit facility - available [1]	$ 497.9	$ --	$ --	$ --	$ 497.9
Unsecured credit agreement	20.0				20.0
Receivable securitization facility [2]	176.0	--	--	176.0	--
Energy operations letter of credit	0.5	0.5	--	--	--
Total commercial commitments	$ 694.4	$ 0.5	$ --	$ 176.0	$ 517.9

1 *See note 4 above.*

2 *See note 5 above.*

OFF-BALANCE SHEET ARRANGEMENTS

Fredonia 3 and 4 Operating Lease. PSE leases two combustion turbines for its Fredonia 3 and 4 electric generating facility pursuant to a master operating lease that was amended for this purpose in April 2001. The lease has a term expiring in 2011, but can be canceled by PSE at any time. Payments under the lease vary with changes in the London Interbank Offered Rate (LIBOR). At March 31, 2006, PSE's outstanding balance under the lease was $53.3 million. The expected residual value under the lease is the lesser of $37.4 million or 60% of the cost of the equipment. In the event the equipment is sold to a third party upon termination of the lease and the aggregate sales proceeds are less than the unamortized value of the equipment, PSE would be required to pay the lessor contingent rent in an amount equal to the deficiency up to a maximum of 87% of the unamortized value of the equipment.

UTILITY CONSTRUCTION PROGRAM

Utility construction expenditures for generation, transmission and distribution are designed to meet continuing customer growth and to improve efficiencies of PSE's energy delivery systems. Construction expenditures, excluding equity Allowance for Funds Used during Construction (AFUDC) and customer refundable contributions, were $107.7 million for the three months ended March 31, 2006. Utility construction expenditures, excluding AFUDC and excluding new generation resources other than the Wild Horse project (which will be determined as the company proceeds through the least cost planning process) are anticipated to be the following in 2006 and 2007:

CAPITAL EXPENDITURE PROJECTIONS (DOLLARS IN MILLIONS)	2006	2007
Energy delivery, technology and facilities	$ 454	$ 500
Wild Horse wind project	317	--
Total capital expenditures	771	500
Chelan contract payment[1]	89	--
Total expenditures	$ 860	$ 500

1 *The Chelan contract payment represents a capacity reservation charge in conjunction with an impending new contract for hydroelectric power beginning 2011. PSE obtained an accounting order from the Washington Commission that treated the payment made on April 26, 2006 as a regulatory asset.*

The proposed utility construction expenditures and any new generation resource expenditures that may be incurred are anticipated to be funded with a combination of cash from operations, short-term debt, long-term debt and equity. Construction expenditure estimates, including any new generation resources, are subject to periodic review and adjustment in light of changing economic, regulatory, environmental and efficiency factors.

CAPITAL RESOURCES

CASH FROM OPERATIONS

Cash generated from operations for the three months ended March 31, 2006 was $138.4 million. During that period, $2.0 million was used for AFUDC, which reduced interest expense, and $25.9 million for payment of dividends. Consequently, cash flows available for utility construction expenditures and other capital expenditures were $110.5 million or 102.6% of the $107.7 million in construction expenditures (net of AFUDC and customer refundable contributions) and other capital expenditure requirements for the three months ended March 31, 2006. For the three months ended March 31, 2005, cash generated from operations was $45.7 million, $1.5 million was used for AFUDC, which reduced interest expense, and $21.9 million was used for payment of dividends. Therefore, cash flows available for utility construction expenditures and other capital expenditures were $22.3 million, or 18.0% of the $124.0 million in construction expenditures (net of AFUDC and customer refundable contributions) and other capital expenditure requirements for the three month period ended March 31, 2005. The following table provides a summary of cash available and construction expenditures:

(DOLLARS IN MILLIONS) (UNAUDITED) For the three months ended March 31,	2006	2005
Cash from operations	$ 138.4	$ 45.7
Less: Dividends paid	(25.9)	(21.9)
AFUDC	(2.0)	(1.5)
Cash available for construction expenditures	$ 110.5	$ 22.3
Construction and energy efficiency expenditures	$ 112.3	$ 129.1
Less: AFUDC	(2.0)	(1.5)
Cash received from refundable customer contributions	(2.6)	(3.6)
Net construction and energy efficiency expenditures	$ 107.7	$ 124.0

The overall cash generated from operating activities for the three month period ended March 31, 2006 increased $92.7 million compared to the same period in 2005. This increase is primarily attributable to a payment of $150 million in 2005 related to the Rainier Receivables accounts receivable securitization sales that were outstanding at December 31, 2004 compared to no activity under the Rainier Receivables accounts receivable securitization at December 31, 2005. This is due to termination of the Rainier Receivable accounts receivable securitization program in December 2005. As a result, cash from operations increased due to collection of accounts receivable in 2006. In addition, decrease in gas inventory resulted in an increase in cash available for operating activities of $33.6 million, which was collected from customers through the PGA mechanism. The increases in cash available for operating activities was offset by payments of accounts payable primarily related to energy purchases and repayment of collateral deposits which accounted for cash used of $70.6 million and $18 million, respectively.

FINANCING PROGRAM

Financing utility construction requirements and operational needs are dependent upon the cost and availability of external funds through capital markets and from financial institutions. Access to funds is dependent upon factors such as general economic conditions, regulatory authorizations and policies, and Puget Energy's and PSE's credit ratings.

RESTRICTIVE COVENANTS

In determining the type and amount of future financing, PSE may be limited by restrictions contained in its electric and gas mortgage indentures, articles of incorporation and certain loan agreements. Under the most restrictive tests, at March 31, 2006, PSE could issue:

- approximately $275 million of additional first mortgage bonds under PSE's electric mortgage indenture based on approximately $458 million of electric bondable property available for issuance, subject to an interest coverage ratio limitation of 2.0 times net earnings available for interest, which PSE exceeded at March 31, 2006;
- approximately $223 million of additional first mortgage bonds under PSE's gas mortgage indenture based on approximately $372 million of gas bondable property available for issuance, subject to an interest coverage ratio limitation of 1.75 times net earnings available for interest, which PSE exceeded at March 31, 2006;

- approximately $663 million of additional preferred stock at an assumed dividend rate of 6.875%; and
- approximately $406 million of unsecured long-term debt.

At March 31, 2006, PSE had approximately $3.8 billion in electric and gas ratebase to support the interest coverage ratio limitation test for net earnings available for interest.

CREDIT RATINGS

Neither Puget Energy nor PSE has any debt outstanding that would accelerate debt maturity upon a credit rating downgrade. A ratings downgrade could adversely affect the ability to renew existing, or obtain access to new, credit facilities and could increase the cost of such facilities. For example, under PSE's revolving credit facility, the borrowing costs and commitment fee increase as PSE's secured long-term debt ratings decline. A downgrade in commercial paper ratings could preclude PSE's ability to issue commercial paper under its current programs. The marketability of PSE commercial paper is currently limited by the A-3/P-2 ratings by Standard & Poor's and Moody's Investors Service. In addition, downgrades in any or a combination of PSE's debt ratings may prompt counterparties on a contract by contract basis in the wholesale electric, wholesale gas and financial derivative markets to require PSE to post a letter of credit or other collateral, make cash prepayments, obtain a guarantee agreement or provide other mutually agreeable security.

The ratings of Puget Energy and PSE, as of April 26, 2006, were as follows:

	Ratings	
	Standard & Poor's	Moody's
Puget Sound Energy		
Corporate credit/issuer rating	BBB-	Baa3
Senior secured debt	BBB	Baa2
Shelf debt senior secured	BBB	(P)Baa2
Trust preferred securities	BB	Ba1
Preferred stock	BB	Ba2
Commercial paper	A-3	P-2
Revolving credit facility	*	Baa3
Ratings outlook	Stable	Stable
Puget Energy		
Corporate credit/issuer rating	BBB-	Ba1

* *Standard & Poor's does not rate credit facilities.*

SHELF REGISTRATIONS, LONG-TERM DEBT AND COMMON STOCK ACTIVITY

On March 16, 2006, Puget Energy and PSE filed a shelf registration statement with the Securities and Exchange Commission for the offering of:

- common stock of Puget Energy;
- senior notes of PSE, secured by first mortgage bonds;
- preferred stock of PSE; and
- trust preferred securities of Puget Sound Energy Capital Trust III.

The registration statement is valid for three years and does not specify the amount of securities that the Company may offer. The Company is subject to restrictions under PSE's indentures and restated articles of incorporation on the amount of first mortgage bonds, unsecured debt and preferred stock that the Company may issue.

Based on PSE's goal to become a more vertically integrated utility, it is expected that further issuances of debt will be utilized within one to two years to fund acquisitions of new generating resources. The structure, timing and amount of such financings are dependent on market conditions, projects available to be developed, and financing needed at the time of any such acquisitions.

LIQUIDITY FACILITIES AND COMMERCIAL PAPER

PSE's short-term borrowings and sales of commercial paper are used to provide working capital and funding of utility construction programs.

PSE Credit Facilities

The Company has two committed credit facilities that provide, in aggregate, $700 million in short-term borrowing capability. These include a $500 million credit agreement and a $200 million accounts receivable securitization facility. In addition, PSE has an uncommitted $20 million unsecured credit agreement with a bank with no expiration date. The unsecured credit agreement can be terminated by either party upon written notice. PSE pays a varying interest rate on outstanding borrowings based on terms entered into at the time of the borrowings. There were no amounts outstanding under the unsecured credit agreement at March 31, 2006.

Credit Agreement. In March 2005, PSE entered into a five-year, $500 million unsecured credit agreement with a group of banks. In April 2006, PSE amended this credit agreement to extend the expiration date from April 2010 to April 2011. The agreement is primarily used to provide credit support for commercial paper and letters of credit. Under the terms of the credit agreement, PSE pays a floating interest rate on outstanding borrowings based either on the agent bank's prime rate or on LIBOR plus a marginal rate based on PSE's long-term credit rating at the time of borrowing. PSE pays a commitment fee on any unused portion of the credit agreement also based on long-term credit ratings of PSE. At March 31, 2006, there was $0.5 million outstanding under a letter of credit and $1.6 million commercial paper outstanding, effectively reducing the available borrowing capacity under the credit facility to $497.9 million.

Receivables Securitization Facility. PSE entered into a five-year Receivable Sales Agreement with PSE Funding, Inc. (PSE Funding), a wholly owned subsidiary, on December 20, 2005. Pursuant to the Receivables Sales Agreement, PSE sells all of its utility customer accounts receivable and unbilled utility revenues to PSE Funding. In addition, PSE Funding entered into a Loan and Servicing Agreement with PSE and two banks. The Loan and Servicing Agreement allows PSE Funding to use the receivables as collateral to secure short-term loans, not exceeding the lesser of $200 million or the borrowing base of eligible receivables which fluctuate with the seasonality of energy sales to customers. All loans from this facility will be reported as short-term debt in the financial statements.

The PSE Funding facility expires in December 2010, and is terminable by PSE and PSE Funding upon notice to the banks. During the three months ended March 31, 2006, PSE Funding borrowed a cumulative amount of $67.0 million secured by accounts receivable and had $24.0 million of loans secured by accounts receivable pledged as collateral at March 31, 2006.

STOCK PURCHASE AND DIVIDEND REINVESTMENT PLAN

Puget Energy has a Stock Purchase and Dividend Reinvestment Plan pursuant to which shareholders and other interested investors may invest cash and cash dividends in shares of Puget Energy's common stock. Since new shares of common stock may be purchased directly from Puget Energy, funds received may be used for general corporate purposes. Puget Energy issued $3.5 million (166,900 shares) of common stock under the Stock Purchase and Dividend Reinvestment Plan for the three months ended March 31, 2006, respectively, compared to $3.6 million (151,800 shares) for the three months ended March 31, 2005, respectively.

COMMON STOCK OFFERING PROGRAMS

To provide additional financing options, Puget Energy entered into agreements in July 2003 with two financial institutions under which Puget Energy may offer and sell shares of its common stock from time to time through these institutions as sales agents, or as principals. Sales of the common stock, if any, may be made by means of negotiated transactions or in transactions that may be deemed to be "at-the-market" offerings as defined in Rule 415 promulgated under the Securities Act of 1933, including in ordinary brokers' transactions on the New York Stock Exchange at market prices.

Other

FERC HYDROELECTRIC PROJECTS AND LICENSES

Baker River project. The Baker River project consists of the Lower Baker Development (constructed in 1925) and the Upper Baker Development (constructed in 1959). The Baker River project's current license expires on April 30, 2006, and PSE submitted an application for a new license to FERC on April 30, 2004. On November 30, 2004, PSE and 23 parties comprised of federal, state and local governmental organizations, Native American Indian tribes, environmental and other non-governmental entities filed a proposed comprehensive settlement agreement on all issues relating to the relicensing of the Baker River project. The proposed settlement includes a set of proposed license articles and, if approved by FERC without material modification, would allow for a new license of 45 years or more. The proposed settlement would require an investment of approximately $360 million over the next 30 years (capital expenditures and operations and maintenance cost) in order to implement the conditions of the new license. The proposed settlement is subject to contingencies that have yet to be resolved and is subject to additional regulatory approvals yet to be attained from various agencies. FERC has not yet ruled on the proposed settlement and its ultimate outcome remains uncertain. On April 7, 2006, FERC issued a Draft Environmental Impact Statement (DEIS) for the Baker River project. The contents of the DEIS and potential impacts on the proposed settlement and the schedule for issuing the new license are being evaluated by all parties.

White River project. The White River project was built in 1911 and was operated as a hydropower facility until January 15, 2004. PSE submitted a license application to FERC in 1983, and in December 1997, FERC issued a proposed license for the project. PSE appealed the 1997 license because it contained terms and conditions that would render ongoing operations of the project uneconomic relative to alternative resources. In November 2003, PSE determined that it could no longer continue to operate economically the project due to additional conditions primarily related to two listings under the Endangered Species Act. On December 23, 2003, PSE notified FERC that it rejected the 1997 license for the White River project and on January 15, 2004, generation of electricity ceased at the White River project. PSE is actively seeking to sell the project to one or more entities interested in maintaining the reservoir for commercial purposes. On February 16, 2006, PSE entered into a Letter of Intent with the Cascade Land Conservancy to facilitate efforts to sell certain former project properties to one or more third parties that may have an interest in acquiring these properties for potential open space, habitat and recreational interests.

In the PCORC Order issued on April 7, 2004, the Washington Commission approved PSE's recovery on the unamortized White River plant investment. At March 31, 2006, the White River project net book value totaled $66.2 million, which included $44.6 million of net utility plant, $15.8 million of capitalized FERC licensing costs, $3.9 million of costs related to construction work in progress and $1.4 million related to dam operations and safety. PSE sought recovery of the relicensing, other construction work in progress and dam operations and safety costs in its general rate filing of April 2004 over a 10-year amortization period. On February 18, 2005, the Washington Commission agreed to allow PSE to recover the White River net utility plant costs noted above. However, amortization of the FERC licensing and other costs will not begin until all costs and any sales proceeds are known.

In January 2001, certain environmental groups gave notice of their intent to sue for alleged violations of the Endangered Species Act, but no such lawsuit has been filed. In May 2004, the Puyallup Indian Tribe gave PSE notice of intent to sue for an alleged violation of water quality laws associated with the release of water from the White River project reservoir. No such lawsuit has been filed and PSE is in discussion with the Puyallup Indian Tribe regarding their concerns. Additionally, PSE sought further direction from the Washington State Department of Ecology (Ecology) as to whether any additional actions are necessary to maintain compliance with applicable water quality laws, and Ecology has not recommended any such further actions.

Homeowners and others interested in preserving the project reservoir (Lake Tapps) have expressed concern over the possible loss of the reservoir and there has been a solicitation of interest in a potential lawsuit against PSE to preserve the reservoir, but no such lawsuit has been filed to date.

In September 2005, the Company renewed its contract with the United States Army Corps of Engineers (COE) to maintain operation of the White River diversion dam to support the COE's ongoing operation of its Mud Mountain Dam fish passage facilities. The agreement provides for reimbursement of a portion of PSE's operating costs and directs PSE to operate the diversion dam in accordance with measures determined by federal agencies to be necessary to protect listed species and habitat. This contract expires in September 2010, unless terminated prior to that date.

In June 2003, Ecology approved an application for new municipal water rights related to the White River project reservoir. This approval was sought in connection with PSE's ongoing efforts to sell the White River project to be used for commercial purposes. An appeal of Ecology's decision approving the new municipal water rights was subsequently filed with the Washington State Pollution Control Hearings Board. In July 2004, this decision was remanded back to Ecology for further analysis of non-hydropower operations. The Company has been advised by Ecology that Ecology anticipates issuing a revised decision during the second quarter of 2006; however, no firm date has been set for any such revised decision. Any proceeds from the sale of the White River water rights will reduce the balance of the deferred regulatory asset. Neither the outcome of this matter nor any potential associated costs can be predicted at this time.

ELECTRIC REGULATION AND RATES

Rate Case. On February 15, 2006, PSE filed a request with the Washington Commission to increase electric rates by 9.2% or $148.8 million annually. The Company is proposing in its filing to change the annual PCA sharing bands to the following:

POWER COST VARIABILITY	CUSTOMERS' SHARE	COMPANY'S SHARE
+/- $0 - $25 million	50%	50%
+/- $25 - $120 million	90%	10%
+/- $120 million	95%	5%

In addition to the change in sharing bands for the PCA, the Company is requesting the Washington Commission to approve a new depreciation tracker mechanism that would allow the Company to recover increased depreciation expense associated with new plant investment incurred between rate filings. The electric depreciation tracker is 0.5%, or $7.9 million annually, of the rate increase over current rate levels.

PCA Mechanism. On June 20, 2002, the Washington Commission approved a PCA mechanism that triggers if PSE's costs to provide customers' electricity falls outside certain bands from a normalized level of power costs established in an electric rate case. The cumulative maximum pre-tax earnings exposure due to power cost variations over the four-year period ending June 30, 2006 is limited to $40 million plus 1% of the excess. Upon expiration of the $40 million cumulative cap, the annual power cost variability will be subject to the bands in the table below. All significant variable power supply cost drivers are included in the PCA mechanism (hydroelectric generation variability, market price variability for purchased power and surplus power sales, natural gas and coal fuel price variability, generation unit forced outage risk and transmission cost variability). PSE's cumulative excess power costs at March 31, 2006 was $40.2 million but it anticipates being below the $40 million cap in May and June 2006.

Upon expiration of the cumulative cap, the most significant risks are hydroelectric generation variability and wholesale market prices of natural gas and power. On an annual July through June basis, the current PCA mechanism apportions increases or decreases in power costs, on a graduated scale, between PSE and its customers in the following manner:

ANNUAL POWER COST VARIABILITY	JULY-DECEMBER 2006 POWER COST VARIABILITY[1]	CUSTOMERS' SHARE	COMPANY'S SHARE [2]
+/- $20 million	+/- $10 million	0%	100%
+/- $20 - $40 million	+/- $10 - $20 million	50%	50%
+/- $40 - $120 million	+/- $20 - $60 million	90%	10%
+/- $120 million	+/- $60 million	95%	5%

1 *In October 2005, the Washington Commission in its Power Cost Only Rate Case order made a provision to reduce the power cost variability amounts to half the annual power cost variability for the period July 1, 2006 through December 31, 2006.*

2 *Over the four-year period July 1, 2002 through June 30, 2006, the Company's share of pre-tax power cost variations is capped at a cumulative $40 million plus 1% of the excess. Power cost variation after June 30, 2006 will be apportioned on an annual basis, on the graduated scale without a cumulative cap.*

Based on past activity under the PCA mechanism and volatility of power costs, it is possible that PSE could experience higher expenses associated with excess power costs based on the sharing arrangement once the cumulative $40 million cap expires on June 30, 2006. As such, the risk dynamics change for PSE and its customers. On October 20, 2005, the Washington Commission approved an amendment to the PCA mechanism changing the PCA period to a calendar year beginning January 1, 2007. The Washington Commission also made provision to reduce the graduated scale to half the annual excess power costs for the period July 1, 2006 through December 31, 2006 without a cap on excess power costs. In addition, the Washington Commission order requires PSE to update the power cost baseline rate accepted in the 2005 PCORC proceeding by filing a tariff change to the power cost rate during May 2006 which would be effective July 1, 2006.

GAS REGULATION AND RATES

On February 15, 2006, PSE filed a gas general rate case requesting an increase in gas general rates of 5.3% or $51.3 million annually, and to approve a depreciation tracker mechanism and a decoupling mechanism for natural gas residential and small commercial customers. The natural gas depreciation tracker is 1.2% or $10.9 million, of the rate increase over current rate levels. The gas decoupling mechanism does not have an impact on the current rate increase; however, it is designed to stabilize revenue changes due to load variations between regulatory filings. The resolution of the general rate case may be up to an 11-month process from the time the general rate case is filed.

OTHER

Chelan County PUD. PSE has contracted to purchase a portion of the output from the Rocky Reach and Rock Island hydroelectric generating facilities located on the mid-Columbia River owned by Chelan County PUD (Chelan). On February 3, 2006, PSE and Chelan entered into a new Power Sales Agreement and a related Transmission Agreement for 25% of the output of the Rocky Reach and Rock Island facilities in exchange for PSE paying 25% of the operating costs of the facilities. PSE's share of the output represents approximately 487 MW of capacity and 243 average MW of energy. The agreements terminate in 2031 and provide that PSE will begin to receive power upon expiration of PSE’s existing long-term contracts with Chelan for the Rocky Reach and Rock Island output (expiring in 2011 and 2012, respectively). FERC granted approval of the agreement on March 28, 2006, and PSE made a non-refundable capacity reservation payment of $89 million on April 26, 2006, to Chelan under the terms of the agreement. PSE believes that the new agreements with Chelan will lower its overall power costs during the 20-year contract period compared to other available alternatives, secure critical operational flexibility, reduce PSE’s projected long-term energy and capacity deficit and continue PSE’s long-term relationship with the public utility district. PSE filed for an accounting order from the Washington Commission in April 2006 for approval to recognize such payments as a regulatory asset with accrual of interest at the Company’s net of tax rate of return. On April 26, 2006, the Washington Commission approved the accounting petition to defer the capacity reserve payment plus interest on a temporary basis until resolution of PSE’s electric general rate case later this year.

PROCEEDINGS RELATING TO THE WESTERN POWER MARKET

Puget Energy’s and PSE’s Annual Report on Form 10-K for the year ended December 31, 2005 includes a summary of the western power market proceedings described below. The following discussion provides a summary of material developments in these proceedings that occurred during the period covered by this report and of any new material proceedings instituted during the period covered by this report. PSE intends to vigorously defend against each of these cases and does not expect the ultimate resolution of these proceedings in the aggregate to have a material adverse impact on the financial condition, results of operations or liquidity of the Company. However, there can be no assurances in that regard because litigation is subject to numerous uncertainties and PSE is unable to predict the ultimate outcome of these matters. Accordingly, there can be no guarantee that these proceedings, either individually or in the aggregate, will not materially and adversely affect PSE’s financial condition, results of operations or liquidity.

1. **California Receivable and California Refund Proceeding.** In 2001, PG&E and Southern California Edison failed to pay the California Independent System Operator Corporation (CAISO) and the California PX for energy purchases. The CAISO in turn failed to pay various energy suppliers, including PSE, for energy sales made by PSE into the California energy market during the fourth quarter 2000. Both PG&E and the California PX filed for bankruptcy in 2001, further constraining PSE’s ability to receive payments due to bankruptcy court controls placed on the distribution of funds by the

California PX and the escrow of funds owed by PG&E for purchases during the fourth quarter 2000 that are owed by the California PX.

a. ***California Refund Proceeding.*** On July 25, 2001, FERC ordered an evidentiary hearing (Docket No. EL00-95) to determine the amount of refunds due to California energy buyers for purchases made in the spot markets operated by the CAISO and the California PX during the period October 2, 2000 through June 20, 2001 (refund period). The CAISO continues its efforts to prepare revised settlement statements based on newly recalculated costs and charges for spot market sales to California during the refund period. If the refunds required by the formula would cause a seller to recover less than its actual costs for the refund period, FERC has held that the seller would be allowed to document these costs and limit its refund liability commensurately. In August 2005, PSE submitted its audited Fuel Cost Allowance Claim with the CAISO. That claim is currently pending. In September 2005, PSE submitted an additional cost filing claim pursuant to FERC's August 2005 order, demonstrating an overall revenue shortfall for sales into the California spot markets during the refund period after the mitigated market clearing price methodology was applied to its transactions. In January 2006, FERC issued its order on cost filings accepting PSE's cost filing claim subject to certain modifications and the utilization of final CAISO data. PSE does not agree with all of FERC's rulings and sought rehearing of some of FERC's determinations. Once the CAISO receives updated cost offset filings from sellers, including PSE, it will continue efforts to prepare revised settlement statements for spot market sales to California during the refund period. Thus, PSE's ability to recover all or a part of its costs remains uncertain at this time. Global settlements have been announced and/or approved, including settlements between the California Parties and Williams, Duke, El Paso, Mirant, Dynegy, Enron, Reliant, Public Service Company of Colorado and Idacorp. These settlements, supported by a statement from FERC Chairman Joseph Kelliher, may suggest that the process momentum toward settlement in the California Refund Proceedings is increasing.

Many of the numerous orders that FERC issued in Docket No. EL00-95 are on appeal before the United States Court of Appeals for the Ninth Circuit. Some of those issues have been consolidated as a result of a case management conference conducted on September 21, 2004. The Ninth Circuit ordered on October 22, 2004 that briefing proceed in two rounds. The first round was limited to three issues: (1) which parties are subject to FERC's refund jurisdiction in light of the exemption for government-owned utilities in section 201(f) of the Federal Power Act (FPA); (2) the temporal scope of refunds under section 206 of the FPA; and (3) which categories of transactions are subject to refunds. PSE joined the brief of the Competitive Supplier Group, which argued that FERC has proposed to require payment of refunds without proper notice to sellers, without proper limits on the type of transactions affected and without a finding that the transactions subject to refund in fact produced prices that were unjust and unreasonable. The court heard oral argument on April 12 and 13, 2005. On September 6, 2005, the court ruled that, as to the first issue, FERC does not have refund authority over wholesale electric sales made by governmental utilities. No decision has been issued on the other issues argued in April 2005. The order remanding the proceeding back to FERC and the time for seeking rehearing in the governmental utilities case has been extended until 45 days after a decision on the other issues identified above. The parties await a decision from the court on the remaining two other issues. Procedures will be established for the remaining issues, if necessary, after the court's disposition of the first round of issues; however, the Court issued an order April 11, 2006 that convenes a case management conference in San Francisco on May 26, 2006, to discuss the process for resolving remaining issues.

b. ***CAISO Receivable***. At March 31, 2006, PSE had a net receivable totaling $21.2 million in connection with wholesale sales in 2000 to the California Independent System Operator (CAISO) and counterparties where payment to PSE was conditioned on the counterparties being paid by the California Power Exchange. In August 2005, PSE submitted a Fuel Cost Adjustment Claim for $3.4 million related to sales in 2000 to the CAISO, pursuant to FERC's California refund proceeding.

Pursuant to an order issued by FERC in August 2005, PSE also submitted a Portfolio Cost Claim in September 2005 for $9.3 million to the CAISO. On January 26, 2006, FERC issued its order on Cost Filings accepting PSE's cost filing subject to certain modifications, which appear to have the effect of reducing PSE's

Portfolio Claim substantially. PSE filed a revised Portfolio Claim in the amount of $2.3 million on March 3, 2006. However, the Company does not believe the claim will be reduced below the $21.2 million receivable. PSE does not agree with all of FERC's rulings and sought rehearing. PSE's ability to recover all or a portion of these claims is uncertain at the present time.

Based upon FERC orders, PSE has determined a range related to its CAISO receivable to be between $21.2 million (PSE's net receivable balance) and $28.0 million, including interest, on its past due receivables as of March 31, 2006.

2. **Port of Seattle Suit.** On May 21, 2003, the Port of Seattle commenced suit in federal court in Seattle against 22 energy sellers, alleging that their conduct during 2000 and 2001 constituted market manipulation, violated antitrust laws and damaged the Port of Seattle. The Port had a contract to purchase its energy supply from PSE at the time. The Port's contract linked the price of the energy sold to the Port to an index price for energy sold at wholesale at the Mid-Columbia trading hub. The Port alleged that the Mid-Columbia price was intentionally affected improperly by the defendants, including PSE, and alleges damages of over $30 million. On May 12, 2004, the district court dismissed the lawsuit. The Port of Seattle filed an appeal to the United States Court of Appeals for the Ninth Circuit. After briefing and oral arguments on March 30, 2006, the Ninth Circuit issued an order dismissing the case.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Effective January 1, 2006, the Company adopted the fair value recognition provisions of SFAS No. 123R, "Share-Based Payment," using the modified-prospective transition method. Results for prior periods have not been restated, as provided for under the modified-prospective method. Prior to 2006, stock-based compensation plans were accounted for according to Accounting Principles Board (APB) No. 25, "Accounting for Stock Issued to Employees," and related interpretations as allowed by SFAS No. 123, "Accounting for Stock-Based Compensation." In 2003, the Company adopted the fair value based accounting of SFAS No. 123 using the prospective method under the guidance of SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure." The Company applied SFAS No. 123 accounting to stock compensation awards granted subsequent to January 1, 2003, while grants prior to 2003 continued to be accounted for using the intrinsic value method of APB No. 25.

The adoption of SFAS 123R resulted in a cumulative benefit from an accounting change amounting to $0.1 million, net of tax, for the quarter ended March 31, 2006. The cumulative effect adjustment is primarily the result of the inclusion of estimated forfeitures occurring before award vesting dates in the computation of compensation expense. Under SFAS No. 123, the Company elected to reduce awards as forfeitures occurred instead of estimating the amount of forfeiture over the vesting period. For SFAS No. 123R, the Company has determined its forfeitures based on historical forfeitures.

As a result of adopting SFAS No. 123R on January 1, 2006, the Company's income before income taxes and net income from continuing operations for the quarter ended March 31, 2006, are $0.1 million and $0.1 million higher, respectively, than if it had continued to account for share-based compensation under SFAS No. 123. Basic and diluted earnings per share for income from continuing operations for the quarter ended March 31, 2006, would have been $0.80 and $0.79, respectively, if the Company had not adopted SFAS No. 123R, compared to basic and diluted earnings per share of $0.80 and $0.79, respectively. As of March 31, 2006, there was $6.0 million of total unrecognized compensation cost related to stock-based compensation plans. That cost is expected to be recognized over a weighted average period of 2.25 years.

The portion of stock-based grants that can be paid in cash are classified and accounted for as liabilities under SFAS No. 123R. As a result, the expense recognized over the performance period for a portion of the performance share grants will equal the fair value (i.e. cash value) of the award as of the last day of the performance period times the number of awards that are earned. Furthermore, SFAS No. 123R requires the quarterly expense recognized during the performance period be based on the fair value of the performance share grants as of the end of the most recent quarter. Prior to the end of the performance period, compensation costs for the liability portion of performance share grants are based on the awards' most recent quarterly fair values and the number of months of service rendered during the performance period. The fair value of the stock-based grants is based on the closing price of the Company's common stock on the date of measurement and historical performance of the certain share grants and prospective analysis using the Capital Asset Pricing Model and expected EPS growth rates. Based on this analysis, the Company's total shareholder returns would need to significantly increase as compared to other companies to have a material impact on the Company's financial statements. Shares granted prior to 2006 were valued using the Black-Scholes option pricing model.

Item 3. **<u>Quantitative and Qualitative Disclosure About Market Risk</u>**

ENERGY PORTFOLIO MANAGEMENT

The regulatory mechanisms of the PGA and the PCA mitigate the impact of commodity price volatility on the Company. The PGA mechanism passes through increases and decreases in the cost of natural gas supply to customers. The PCA mechanism provides for a sharing of costs and benefits that are graduated over four levels of power cost variances with an overall cap of $40 million (+/-) plus 1% of the excess over the $40 million cap over the four-year period ending June 30, 2006. For the period July 1, 2006 through December 31, 2006 the sharing bands will be half of the annual bands without a cap for excess power costs and beginning January 1, 2007 the PCA mechanism will provide sharing of costs and benefits that are graduated over four levels for each calendar year without a maximum cap for excess power costs.

The Company is focused on managing commodity price exposure and risks associated with volumetric variability in the gas portfolio and electric portfolio for its customers. Gas and electric portfolio exposure is managed in accordance with Company polices and procedures. The Energy Management Committee, which is composed of Company officers, provides policy-level and strategic direction for management of the energy portfolio. The Finance and Budget Committee of the Company's Board of Directors periodically assesses risk management policies.

The nature of serving regulated electric customers with its wholesale portfolio of owned and contracted resources exposes the Company and its customers to some volumetric and commodity price risks within the sharing mechanism of the PCA. The Company's energy portfolio management function monitors and manages these risks using analytical models and tools. The Company manages its energy supply portfolio to achieve three primary objectives:

- ensure that physical energy supplies are available to serve retail customer requirements;
- manage portfolio risks to limit undesired impacts on the Company's costs; and
- maximize the value of the Company's energy supply assets.

The Company is not engaged in the business of assuming risk for the purpose of speculative trading revenues. Therefore wholesale market transactions are focused on balancing the Company's energy portfolio, reducing costs and risks where feasible, and reducing volatility in wholesale costs and margin in the portfolio. In order to manage risks effectively, the Company enters into physical and financial transactions, which are appropriate for the service territory of the Company and are relevant to its regulated electric and gas portfolios.

The risk metrics the Company employs are aimed at assessing exposure for the purpose of developing strategies to reduce the potential exposure on a cost-effective basis in regulated utility gas and electric portfolios. Specifically, the amount of risk exposure is defined by time period and by portfolio. This is determined through statistical methods aimed at forecasting risk.

The energy portfolio management staff models forecasted load requirements and expected resource availability, and projects the net deficit or surplus position resulting from any imbalance between load requirements and existing resources. However, the portfolios are subject to major sources of variability (e.g., hydroelectric generation, outage risk, regional economic factors, temperature-sensitive retail sales and market prices for gas and power supplies). At certain times, these sources of variability can mitigate portfolio imbalances and at other times they can exacerbate portfolio imbalances. Because of the volumetric and cost variability within the electric and gas portfolios, the Company runs market simulations to model potential risk scenarios. In this way, strategies can be developed to address the expected case as well as other potential scenarios. Resources in the gas portfolio include gas supply arrangements, gas storage and gas transportation contracts. Resources in the electric portfolio include power purchase agreements, generating resources and transmission contracts.

The Company's energy portfolio management staff develops hedging strategies to manage deficit or surplus positions in the portfolios. The Company's energy risk policy states that hedging and optimization strategies will be consistent with Company objectives. The Company will engage in transactions that reduce risks in its electric and gas portfolios, and optimize unused capacity where possible. Cost and reliability factors are considered in its hedging strategies. The Company's hedging activities are aimed at removing risks from the Company's electric and gas portfolios, giving important consideration to cost of hedges and lost opportunity in order to find a balance between price stability and least cost. The hedge strategies for the gas and electric portfolios incorporate risk analysis, operational factors and professional judgment of its employees as well as fundamental analysis. Programmatic hedge plans are developed to ensure disciplined hedging and discretion are used in hedging within specific guidelines of the programmatic hedge plans approved by the Energy Management Committee. The Company's programmatic hedging strategies may be modified, as approved by the Energy Management Committee, in response to market fundamental information and trends. Most hedges can be implemented in ways that retain the Company's ability to use its energy supply optimization opportunities. Some hedges are structured similarly to insurance instruments, where the Company pays an insurance premium to protect against certain extreme conditions.

Without jeopardizing the security of supply within its portfolio, the Company also engages in optimizing the portfolio. Optimization may take the form of utilizing excess capacity, shaping flexible resources to capture their highest value and utilizing transmission capacity through third party transactions. As a result, portions of the Company's energy portfolio are monetized through the use of forward price instruments, which help reduce overall costs.

The Company has entered into master netting agreements with counterparties when available to mitigate credit exposure to those counterparties. The Company believes that entering into such agreements reduces risk of settlement default for the ability to make only one net payment. In addition, the Company believes risk is mitigated with an improved position in potential counterparty bankruptcy situations due to a consistent netting approach.

At March 31, 2006, the Company was subject to a range of netting provisions, including both stand alone agreements and the provisions associated with the Western Systems Power Pool agreement of which many energy suppliers in the western United States are a part.

Transactions that qualify as hedge transactions under SFAS No. 133 are recorded on the balance sheet at fair value. Changes in fair value of the Company's derivatives are recorded each period in current earnings or other comprehensive income. Short-term derivative contracts for the purchase and sale of electricity are valued based on daily quoted prices from an independent energy brokerage service. Valuations for short-term and medium-term natural gas financial derivatives are derived from a combination of quotes from several independent energy brokers and are updated daily. Long-term gas financial derivatives are valued based on published pricing from a combination of independent brokerage services and are updated monthly. Option contracts are valued using market quotes and a Monte Carlo simulation process employing stochastic differential equations using market volatilities and prices as inputs to create various commodity forward curves. These simulated forward curves are then used to value various option contracts across a spectrum of commodities.

At March 31, 2006, the Company had a net asset of approximately $34.8 million of energy contracts designated as qualifying cash flow hedges and a corresponding unrealized gain of $22.6 million after-tax recorded in other comprehensive income. These cash flow hedges represent forward financial purchases of gas intended to run PSE-owned electric plants in future periods. If it is determined that it is uneconomical to run the plants in the future period, the hedging relationship is ended and the cash flow hedge is de-designated and any unrealized gains and losses are recorded in the income statement. Gains and losses when these de-designated cash flow hedges are settled are recognized in energy costs and are included as part of the PCA mechanism. Of the amount in other comprehensive income, 99% of the mark-to-market gain for the month of April 2006 has been reclassified out of other comprehensive income to a deferred account in accordance with SFAS No. 71 due to the Company reaching the $40 million cap under the PCA mechanism. Amounts settling after April 30, 2006 have not been deferred under the PCA mechanism as the Company is forecasted to fall below the $40 million cap in May 2006 and the cap expires at June 30, 2006, and the sharing band under the PCA mechanism reset. The Company also had energy contracts that were marked-to-market at a loss of $1.0 million through current earnings for the three months ended March 31, 2006. These mark-to-market adjustments were primarily the result of excluding certain contracts from the normal purchase normal sale exception under SFAS No. 133. A portion of the mark-to-market adjustments for April 2006 has been reclassified to a deferred account in accordance with SFAS No. 71 due to the Company reaching the $40 million cap under the PCA mechanism. At March 31, 2006, the Company also has a net liability of approximately $25.2 million related to the fair value of gas contracts to serve gas customers. All mark-to-market adjustments relating to the natural gas business have been reclassified to a deferred account in accordance with SFAS No. 71 due to the PGA mechanism. The PGA mechanism passes on to customers increases and decreases in the cost of natural gas supply. As the gains and losses on the cash flow hedges are realized in future periods, they will be recorded as gas costs under the PGA mechanism. A hypothetical 10% decrease in the market prices of natural gas and electricity would decrease the fair value of qualifying cash flow hedges and comprehensive income by approximately $5.8 million after-tax and would decrease current earnings for those contracts marked-to-market in earnings by $0.3 million pre-tax. All items affecting comprehensive income are presented after-tax as items recorded in comprehensive income are net of tax.

CREDIT RISK

The Company is exposed to credit risk primarily through buying and selling electricity and gas to serve its customers. Credit risk is the potential loss resulting from a counterparty's non-performance under an agreement. The Company manages credit risk with policies and procedures for, among other things, counterparty analysis, exposure measurement, exposure monitoring, and exposure mitigation.

It is possible that extreme volatility in energy commodity prices could cause the Company to have sub-optimal credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, the Company could suffer a material financial loss. However, as of March 31, 2006, approximately 96% of the Company's energy portfolio was rated investment grade or higher by Standard & Poor's Ratings Services and/or Moody's Investor Services, Inc.

INTEREST RATE RISK

The Company believes its interest rate risk primarily relates to the use of short-term debt instruments, variable-rate notes and leases and long-term debt financing needed to fund capital requirements. The Company manages its interest rate risk through the issuance of mostly fixed-rate debt of various maturities. The Company utilizes bank borrowings, commercial paper, line of credit facilities and accounts receivable securitization to meet short-term cash requirements. These short-term obligations are commonly refinanced with fixed-rate bonds or notes when needed and when interest rates are considered favorable. The Company may enter into swap instruments or other financial hedge instruments to manage the interest rate risk associated with these debts.

In the second quarter 2005, the Company entered into two forward starting swap contracts to hedge against interest rate volatility for a debt offering anticipated to be performed in the second half of 2006. A forward starting swap is a financial arrangement between the Company and a counterparty whereby one of the parties will be required to make a payment to the other party on a specific valuation date based upon the change in value of a designated treasury bond. If interest rates rise related to the hedged debt from the date of issuance of the swap instruments, the Company would receive a payment from the counterparty for the change in the bond value. Alternatively, if interest rates decreased related to the hedged debt from the date of issuance of the swap instruments, the Company would pay the counterparty for the change in bond value. These swap contracts were designated under SFAS No. 133 criteria as cash flow hedges. All financial hedge contracts of this type are reviewed by senior management and presented to the Finance and Budget Committee of the Board of Directors, and are approved prior to execution. At March 31, 2006, the unrealized gain associated with the two swap contracts was $7.7 million after-tax and is included in other comprehensive income. The forward starting swap contracts will settle completely in 2006. A hypothetical 10% decrease in the interest rate of a 30-year Treasury note would result in a loss of $10.5 million net of tax in other comprehensive income. The counterparties calculate the current market value for the existing forward swap positions based on market interest rates and swap rates as of March 31, 2006.

Item 4. **Controls and Procedures**

PUGET ENERGY

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Under the supervision and with the participation of Puget Energy's management, including the Chairman, President and Chief Executive Officer and the Senior Vice President Finance and Chief Financial Officer, Puget Energy has evaluated the effectiveness of its disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934) as of March 31, 2006, the end of the period covered by this report. Based upon that evaluation, the Chairman, President and Chief Executive Officer and the Senior Vice President Finance and Chief Financial Officer of Puget Energy concluded that these disclosure controls and procedures are effective.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There have been no changes in Puget Energy's internal control over financial reporting during the quarter ended March 31, 2006 that have materially affected, or are reasonably likely to materially affect, Puget Energy's internal control over financial reporting.

PUGET SOUND ENERGY

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Under the supervision and with the participation of PSE's management, including the Chairman, President and Chief Executive Officer and the Senior Vice President Finance and Chief Financial Officer, PSE has evaluated the effectiveness of its disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934) as of March 31, 2006, the end of the period covered by this report. Based upon that evaluation, the Chairman, President and Chief Executive Officer and the Senior Vice President Finance and Chief Financial Officer of PSE concluded that these disclosure controls and procedures are effective.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There have been no changes in PSE's internal control over financial reporting during the quarter ended March 31, 2006, that have materially affected, or are reasonably likely to materially affect, PSE's internal control over financial reporting.

PART II OTHER INFORMATION

Item 1. **Legal Proceedings**

See the section titled "Proceedings Relating to the Western Power Market" under Item 2 "Management's Discussion and Analysis of Financial Conditions and Results of Operations" of this Quarterly Report on Form 10-Q.

Contingencies arising out of the normal course of the Company's business exist at March 31, 2006. The ultimate resolution of these issues in part or in the aggregate is not expected to have a material adverse impact on the financial condition, results of operations or liquidity of the Company.

Item 1A. **Risk Factors**

There are no material changes to risk factors previously disclosed by Puget Energy and Puget Sound Energy on Form 10-K, Item 1A.

Item 6. **Exhibits**

See Exhibit Index for list of exhibits.

SIGNATURES

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

PUGET ENERGY, INC.
PUGET SOUND ENERGY, INC.

/S/ JAMES W. ELDREDGE
James W. Eldredge
Vice President, Corporate Secretary
and Chief Accounting Officer

Date: May 4, 2006

Chief accounting officer and officer duly authorized to sign this report on behalf of each registrant

EXHIBIT INDEX

The following exhibits are filed herewith:

10.1 First Amendment to the Amended and Restated Credit Agreement dated April 4, 2006 covering PSE and various banks named therein, Wachovia Bank National Association as administrative agent.

12.1 Statement setting forth computation of ratios of earnings to fixed charges (2001 through 2005 and 12 months ended March 31, 2006) for Puget Energy.

12.2 Statement setting forth computation of ratios of earnings to fixed charges (2001 through 2005 and 12 months ended March 31, 2006) for PSE.

31.1 Chief Executive Officer certification of Puget Energy pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Chief Financial Officer certification of Puget Energy pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.3 Chief Executive Officer certification of Puget Sound Energy pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.4 Chief Financial Officer certification of Puget Sound Energy pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 Chief Executive Officer certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2 Chief Financial Officer certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.