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

FORM 10-Q

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

For the quarterly period ended September 30, 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 October 26, 2006, (i) the number of shares of Puget Energy, Inc. common stock outstanding was 116,401,902 ($.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
Foundation	Puget Sound Energy Foundation
FPA	Federal Power Act
GTN	Gas Transmission Northwest
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)
NWP	Northwest Pipeline
PCA	Power Cost Adjustment
PCORC	Power Cost Only Rate Case
PGA	Purchased Gas Adjustment
PSE	Puget Sound Energy, Inc.
Puget Energy	Puget Energy, Inc.
Tenaska	Tenaska Power Fund, L.P.
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;
- Changes in, adoption of and compliance with laws and regulations, including decisions and policies concerning the environment, climate change (greenhouse gases), emissions, natural resources, and fish and wildlife (including the Endangered Species Act);
- The ability to recover changes in enacted federal state or local tax laws through revenue in a timely manner;
- Natural disasters, such as hurricanes, earthquakes, floods, fires and landslides, 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;
- Financial difficulties of other energy companies and related events, which may affect the regulatory and legislative process in unpredictable ways and also adversely affect the availability of and access to capital and credit markets and/or impact delivery of energy to PSE from it 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 hydro 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 power or natural gas 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 California Independent System Operator (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;
- 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;
- Future losses related to corporate guarantees provided by Puget Energy as a part of the sale of its InfrastruX subsidiary; 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 and this quarterly report for updates.

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 SEPTEMBER 30,		NINE MONTHS ENDED SEPTEMBER 30,	
	2006	2005	2006	2005
Operating Revenues:				
Electric	$ 399,246	$ 375,035	$ 1,247,650	$ 1,140,545
Gas	119,610	111,042	718,655	594,737
Other	607	4,306	5,115	6,866
Total operating revenues	519,463	490,383	1,971,420	1,742,148
Operating Expenses:				
Energy costs:				
Purchased electricity	183,723	200,861	623,793	587,983
Electric generation fuel	36,282	21,058	72,158	54,400
Residential exchange	(35,923)	(34,525)	(131,226)	(126,676)
Purchased gas	68,294	59,151	453,335	359,037
Net unrealized loss (gain) on derivative instruments	(611)	477	214	395
Utility operations and maintenance	87,687	81,645	258,653	240,299
Other operations and maintenance	494	745	2,038	2,045
Depreciation and amortization	65,530	60,550	193,959	178,284
Conservation amortization	7,127	5,633	22,638	16,746
Taxes other than income taxes	46,325	44,784	180,236	165,005
Income taxes	8,281	2,476	64,004	54,649
Total operating expenses	467,209	442,855	1,739,802	1,532,167
Operating income	52,254	47,528	231,618	209,981
Other income (deductions):				
Charitable foundation funding	--	--	(15,000)	--
Other income	5,242	1,350	13,453	5,071
Income taxes	(841)	72	3,956	(887)
Interest charges:				
AFUDC	5,189	2,680	10,238	6,183
Interest expense	(45,900)	(45,695)	(134,129)	(130,307)
Mandatorily redeemable securities interest expense	(23)	(23)	(68)	(68)
Income from continuing operations	15,921	5,912	110,068	89,973
Income (loss) from discontinued segment (net of tax)	1	(1)	51,903	908
Net income before cumulative effect of accounting change	15,922	5,911	161,971	90,881
Cumulative effect of implementation of accounting change (net of tax)	--	--	(89)	--
Net income	$ 15,922	$ 5,911	$ 162,060	$ 90,881
Common shares outstanding weighted average (in thousands)	116,101	100,371	115,910	100,160
Diluted shares outstanding weighted average (in thousands)	116,568	100,964	116,311	100,754
Basic earnings per common share before cumulative effect of accounting change from continuing operations	$ 0.14	$ 0.06	$ 0.95	$ 0.90
Basic earnings per common share from discontinued operations	--	--	0.45	0.01
Cumulative effect from accounting change	--	--	--	--
Basic earnings per common share	$ 0.14	$ 0.06	$ 1.40	$ 0.91
Diluted earnings per common share before cumulative effect of accounting change from continuing operations	$ 0.14	$ 0.06	$ 0.95	$ 0.89
Diluted earnings per common share from discontinued operations	--	--	0.44	0.01
Cumulative effect from accounting change	--	--	--	--
Diluted earnings per common share	$ 0.14	$ 0.06	$ 1.39	$ 0.90

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 SEPTEMBER 30,		NINE MONTHS ENDED SEPTEMBER 30,	
	2006	2005	2006	2005
Net income	$ 15,922	$ 5,911	$ 162,060	$ 90,881
Other comprehensive income, net of tax at 35%:				
Foreign currency translation adjustment	--	2	(327)	(10)
Minimum pension liability adjustment	--	--	145	--
Net unrealized gains (losses) on derivative instruments during the period	(11,220)	37,896	(29,133)	48,484
Reversal of net unrealized gains (losses) on derivative instruments settled during the period	1,281	(4,353)	(8,603)	(3,243)
Settlement of cash flow hedge contracts	(416)	--	13,444	(22,960)
Amortization of cash flow hedge contracts to earnings	76	191	457	264
Deferral of cash flow hedges related to the power cost adjustment mechanism	--	(12,914)	6,252	(4,937)
Other comprehensive income (loss)	(10,279)	20,822	(17,765)	17,598
Comprehensive income	$ 5,643	$ 26,733	$ 144,295	$ 108,479

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

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

ASSETS

	SEPTEMBER 30, 2006 (Unaudited)	DECEMBER 31, 2005
Utility plant: (at original cost, including construction work in progress of $512,432 and $216,513, respectively)		
Electric	$ 5,203,771	$ 4,802,363
Gas	2,093,787	1,991,456
Common plant	447,079	439,599
Less: Accumulated depreciation and amortization	(2,713,179)	(2,602,500)
Net utility plant	5,031,458	4,630,918
Other property and investments	155,357	157,321
Current assets:		
Cash	10,038	16,710
Restricted cash	837	1,047
Accounts receivable, net of allowance for doubtful accounts	199,390	294,509
Secured pledged accounts receivable	--	41,000
Unbilled revenues	90,292	160,207
Purchased gas adjustment receivable	83,652	67,335
Materials and supplies, at average cost	41,816	36,491
Fuel and gas inventory, at average cost	130,163	91,058
Unrealized gain on derivative instruments	19,365	75,037
Deferred income taxes	2,348	--
Prepayments and other	21,606	7,596
Current assets of discontinued operations	--	107,434
Total current assets	599,507	898,424
Other long-term assets:		
Restricted cash	3,739	--
Regulatory asset for deferred income taxes	119,269	129,693
Regulatory asset for PURPA contract buyout costs	173,748	191,170
Unrealized gain on derivative instruments	10,145	28,464
Power cost adjustment mechanism	2,411	18,380
Other	556,875	388,468
Long-term assets of discontinued operations	--	167,113
Total other long-term assets	866,187	923,288
Total assets	$ 6,652,509	$ 6,609,951

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

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

CAPITALIZATION AND LIABILITIES

	SEPTEMBER 30, 2006 (Unaudited)	DECEMBER 31, 2005
Capitalization:		
Common shareholders' investment:		
Common stock $0.01 par value, 250,000,000 shares authorized, 116,394,795 and 115,695,463 shares outstanding, respectively	$ 1,164	$ 1,157
Additional paid-in capital	1,964,007	1,948,975
Earnings reinvested in the business	144,473	69,407
Accumulated other comprehensive income (loss), net of tax at 35%	(10,257)	7,508
Total shareholders' equity	2,099,387	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	37,750	237,750
Long-term debt	2,608,360	2,183,360
Total redeemable securities and long-term debt	2,647,999	2,422,999
Total capitalization	4,747,386	4,450,046
Minority interest in discontinued operations	--	6,816
Current liabilities:		
Accounts payable	224,233	346,490
Short-term debt	103,154	41,000
Current maturities of long-term debt	160,000	81,000
Accrued expenses:		
Taxes	30,445	112,860
Salaries and wages	22,331	15,034
Interest	50,492	31,004
Unrealized loss on derivative instruments	86,318	9,772
Deferred income taxes	--	10,968
Other	32,859	35,694
Current liabilities of discontinued operations	--	55,791
Total current liabilities	709,832	739,613
Long-term liabilities:		
Deferred income taxes	731,008	738,809
Unrealized loss on derivative instruments	770	--
Other deferred credits	463,513	513,023
Long-term liabilities of discontinued operations	--	161,644
Total long-term liabilities	1,195,291	1,413,476
Total capitalization and liabilities	$ 6,652,509	$ 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)

	Nine Months Ended September 30, 2006	2005
Operating activities:		
Net income	$ 162,060	$ 90,881
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	193,959	178,284
Deferred income taxes and tax credits, net	(11,309)	(32,329)
Net unrealized loss on derivative instruments	214	395
Amortization of gas pipeline capacity assignment	(7,951)	--
Non-cash return on regulatory assets	8,167	--
Impairment on InfrastruX investment	(7,269)	13,204
Gain on sale of InfrastruX	(29,765)	--
Cash collateral (paid) received from energy suppliers	(22,020)	31,050
Increase in residential exchange program	434	4,984
Chelan PUD contract initiation prepayment	(89,000)	--
Other	10,198	18,733
Change in certain current assets and liabilities:		
Accounts receivable and unbilled revenue	198,243	70,084
Materials and supplies	(4,408)	(2,781)
Fuel and gas inventory	(39,105)	(29,201)
Prepayments and other	(16,696)	(28,301)
Purchased gas adjustment receivable	(16,318)	(18,419)
Accounts payable	(119,308)	(9,269)
Taxes payable	(78,357)	7,339
Tenaska disallowance reserve	--	(3,156)
Accrued expenses and other	20,718	9,503
Net cash provided by operating activities	152,487	301,001
Investing activities:		
Construction and capital expenditures - excluding equity AFUDC	(579,384)	(406,346)
Energy efficiency expenditures	(21,859)	(10,763)
Cash proceeds from property sales	196	15,830
Refundable cash received for customer construction projects	12,004	10,221
Restricted cash	(3,529)	587
Gross proceeds from sale of InfrastruX, net of cash disposed	263,575	--
Other	5,835	2,348
Net cash used by investing activities	(323,162)	(388,123)
Financing activities:		
Change in short-term debt and leases, net	65,323	230,855
Dividends paid	(78,123)	(65,956)
Payments to minority shareholders of InfrastruX	(10,451)	--
Issuance of common stock	4,241	3,769
Issuance of bonds and notes	550,000	250,000
Redemption of bonds, notes and leases	(190,096)	(250,753)
Redemption of trust preferred stock	(200,000)	(42,500)
Settlement of cash flow hedge of interest rate derivative	20,682	(34,776)
Issuance and redemption costs of bonds and other	(3,760)	(8,356)
Net cash provided by financing activities	157,816	82,283
Net decrease in cash	(12,859)	(4,839)
Cash at beginning of year	22,897	19,771
Cash at end of period	$ 10,038	$ 14,932
Supplemental cash flow information:		
Cash paid for interest (net of capitalized interest)	$ 118,848	$ 123,499
Income taxes paid	97,725	72,940

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 SEPTEMBER 30,		NINE MONTHS ENDED SEPTEMBER 30,	
	2006	2005	2006	2005
Operating revenues:				
Electric	$ 399,246	$ 375,035	$ 1,247,650	$ 1,140,545
Gas	119,610	111,042	718,655	594,737
Other	607	4,306	5,115	6,866
Total operating revenues	519,463	490,383	1,971,420	1,742,148
Operating expenses:				
Energy costs:				
Purchased electricity	183,723	200,861	623,793	587,983
Electric generation fuel	36,282	21,058	72,158	54,400
Residential exchange	(35,923)	(34,525)	(131,226)	(126,676)
Purchased gas	68,294	59,151	453,335	359,037
Net unrealized loss (gain) on derivative instruments	(611)	477	214	395
Utility operations and maintenance	87,687	81,645	258,653	240,299
Other operations and maintenance	243	425	805	925
Depreciation and amortization	65,530	60,550	193,959	178,284
Conservation amortization	7,127	5,633	22,638	16,746
Taxes other than income taxes	46,325	44,784	180,235	165,005
Income taxes	8,481	2,619	64,720	55,449
Total operating expenses	467,158	442,678	1,739,284	1,531,847
Operating income	52,305	47,705	232,136	210,301
Other income (deductions):				
Other income	5,242	1,350	13,097	5,071
Income taxes	(799)	72	(1,289)	(887)
Interest charges:				
AFUDC	5,189	2,680	10,238	6,183
Interest expense	(45,900)	(45,614)	(134,129)	(130,083)
Interest expense on Puget Energy note	(382)	--	(503)	--
Mandatorily redeemable securities interest expense	(23)	(23)	(68)	(68)
Net income before cumulative effect of accounting change	15,632	6,170	119,482	90,517
Cumulative effect of implementation of accounting change (net of tax)	--	--	(89)	--
Net Income	$ 15,632	$ 6,170	$ 119,571	$ 90,517

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 SEPTEMBER 30,		NINE MONTHS ENDED SEPTEMBER 30,	
	2006	2005	2006	2005
Net income	$ 15,632	$ 6,170	$ 119,571	$ 90,517
Other comprehensive income, net of tax at 35%:				
Minimum pension liability adjustment	--	--	145	--
Net unrealized gains (losses) on derivative instruments during the period	(11,220)	37,896	(29,133)	48,484
Reversal of net unrealized gains (losses) on derivative instruments settled during the period	1,281	(4,353)	(8,603)	(3,243)
Settlement of cash flow hedge contracts	(416)	--	13,444	(22,960)
Amortization of cash flow hedge contracts to earnings	76	191	457	264
Deferral of cash flow hedges related to the power cost adjustment mechanism	--	(12,914)	6,252	(4,937)
Other comprehensive income (loss)	(10,279)	20,820	(17,438)	17,608
Comprehensive income	$ 5,353	$ 26,990	$ 102,133	$ 108,125

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

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

ASSETS

	SEPTEMBER 30, 2006 (Unaudited)	DECEMBER 31, 2005
Utility plant: (at original cost, including construction work in progress of $512,432 and $216,513, respectively)		
Electric	$ 5,203,771	$ 4,802,363
Gas	2,093,787	1,991,456
Common plant	447,079	439,599
Less: Accumulated depreciation and amortization	(2,713,179)	(2,602,500)
Net utility plant	5,031,458	4,630,918
Other property and investments	155,357	157,321
Current assets:		
Cash	9,995	16,709
Restricted cash	837	1,047
Accounts receivable, net of allowance for doubtful accounts	200,273	299,938
Secured pledged accounts receivable	--	41,000
Unbilled revenues	90,292	160,207
Purchased gas adjustment receivable	83,652	67,335
Materials and supplies, at average cost	41,816	36,491
Fuel and gas inventory, at average cost	130,163	91,058
Unrealized gain on derivative instruments	19,365	75,037
Deferred income taxes	2,348	--
Prepayments and other	21,035	7,023
Total current assets	599,776	795,845
Other long-term assets:		
Regulatory asset for deferred income taxes	119,269	129,693
Regulatory asset for PURPA contract buyout costs	173,748	191,170
Unrealized gain on derivative instruments	10,145	28,464
Power cost adjustment mechanism	2,411	18,380
Other	556,598	388,009
Total other long-term assets	862,171	755,716
Total assets	$ 6,648,762	$ 6,339,800

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

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

CAPITALIZATION AND LIABILITIES

	SEPTEMBER 30, 2006 (Unaudited)	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	994,760	924,154
Earnings reinvested in the business	232,269	196,248
Accumulated other comprehensive income (loss), net of tax at 35%	(10,257)	7,181
Total shareholder's equity	2,075,810	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	37,750	237,750
Long-term debt	2,608,360	2,183,360
Total redeemable securities and long-term debt	2,647,999	2,422,999
Total capitalization	4,723,809	4,409,620
Current liabilities:		
Accounts payable	224,233	346,490
Short-term debt	103,154	41,000
Short-term note due Puget Energy	24,211	--
Current maturities of long-term debt	160,000	81,000
Accrued expenses:		
Taxes	31,780	111,900
Salaries and wages	21,547	15,034
Interest	50,611	31,004
Unrealized loss on derivative instruments	86,318	9,772
Deferred income taxes	--	10,968
Other	32,854	30,932
Total current liabilities	734,708	678,100
Long-term liabilities:		
Deferred income taxes	734,862	739,162
Unrealized loss on derivative instruments	770	--
Other deferred credits	454,613	512,918
Total long-term liabilities	1,190,245	1,252,080
Total capitalization and liabilities	$ 6,648,762	$ 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)

	NINE MONTHS ENDED SEPTEMBER 30, 2006	NINE MONTHS ENDED SEPTEMBER 30, 2005
Operating activities:		
Net income	$ 119,571	$ 90,517
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	193,959	178,284
Deferred income taxes and tax credits, net	2,276	(31,137)
Net unrealized loss on derivative instruments	214	395
Amortization of gas pipeline capacity assignment	(7,951)	--
Non-cash return on regulatory assets	8,167	--
Cash collateral (paid) received from energy suppliers	(22,020)	31,050
Increase in residential exchange program	434	4,984
Chelan PUD contract initiation prepayment	(89,000)	
Other	14,096	12,968
Change in certain current assets and liabilities:		
Accounts receivable and unbilled revenue	210,578	85,585
Materials and supplies	(5,324)	(2,249)
Fuel and gas inventory	(39,105)	(29,201)
Prepayments and other	(14,012)	(27,628)
Purchased gas adjustment receivable	(16,318)	(18,419)
Accounts payable	(122,257)	(13,080)
Taxes payable	(80,119)	(3,926)
Tenaska disallowance reserve	--	(3,156)
Accrued expenses and other	26,393	3,786
Net cash provided by operating activities	179,582	278,773
Investing activities:		
Construction expenditures - excluding equity AFUDC	(575,108)	(393,619)
Energy efficiency expenditures	(21,859)	(10,763)
Cash proceeds from property sales	196	15,830
Restricted cash	209	587
Refundable cash received for customer construction projects	12,004	10,221
Other	5,939	2,359
Net cash used by investing activities	(578,619)	(375,385)
Financing activities:		
Change in short-term debt, net	62,154	223,871
Loan from Puget Energy	24,211	--
Dividends paid	(83,550)	(67,085)
Investment from Puget Energy	68,635	--
Issuance of bonds and notes	550,000	250,000
Redemption of bonds and notes	(46,000)	(231,000)
Redemption of trust preferred stock	(200,000)	(42,500)
Settlement of cash flow hedge interest rate derivative	20,682	(34,776)
Issuance and redemption cost of bonds and other	(3,809)	(5,037)
Net cash provided by financing activities	392,323	93,473
Net decrease in cash	(6,714)	(3,139)
Cash at beginning of year	16,709	12,955
Cash at end of period	$ 9,995	$ 9,816
Supplemental cash flow information:		
Cash paid for interest (net of capitalized interest)	$ 115,951	$ 116,857
Income taxes paid	91,621	75,482

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 until May 7, 2006, InfrastruX Group, Inc. (InfrastruX). PSE is a public utility incorporated in the State of Washington that furnishes electric and gas services in a territory covering 6,000 square miles, primarily in the Puget Sound region.

The consolidated financial statements of Puget Energy reflect the accounts of Puget Energy and its subsidiaries, PSE and InfrastruX. Puget Energy holds all the common shares of PSE and owned a 90.9% interest in InfrastruX until it was sold on May 7, 2006. 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. At the time that it was owned by Puget Energy, InfrastruX was 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. 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 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 and Corporate Guarantees (Puget Energy Only)

On May 7, 2006, Puget Energy sold InfrastruX to an affiliate of Tenaska Power Fund, L.P. (Tenaska). After repayment of debt, adjustments for working capital, transaction costs and distributions to minority interests, Puget Energy received after-tax cash proceeds of approximately $95.9 million for its 90.9% interest in InfrastruX in the second quarter 2006. The sale resulted in an after-tax gain of $29.8 million for the nine months ended September 30, 2006. Puget Energy accounted for InfrastruX as a discontinued operation under Statement of Financial Accounting Standards (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" in 2005 and 2006.

Under the terms of the sale agreement, Puget Energy is obligated for certain representations and warranties made by InfrastruX concerning its business. Puget Energy obtained a representation and warranty insurance policy and deposited $3.7 million into an escrow account to serve as retention under the policy. As of September 30, 2006, long-term restricted cash in the amount of $3.7 million is included in the accompanying balance sheets; that amount represents management's estimate of the aggregate fair value of the amount potentially payable under those representations and warranties and is Puget Energy's maximum exposure. The obligation expires May 7, 2008. Should Tenaska make any claims against Puget Energy, payment for the claims will be made from the escrow account, and total payments are limited to $3.7 million plus any interest earned while the funds are held in the escrow account. Puget Energy also agreed to indemnify Tenaska for certain potential future losses related to one of InfrastruX's subsidiary companies. Under the indemnity agreement, Puget Energy is liable for certain costs with the maximum amount of loss not to exceed $15.0 million. As of September 30, 2006, a liability in the amount of $5.0 million is included in the accompanying balance sheets; that amount represents Puget Energy's estimate of the fair value of the amount potentially payable using a probability-weighted approach to a range of future cash flows. The obligation expires May 7, 2011. Puget Energy also provided an environmental guaranty as part of the sale agreement. Under the terms of the agreement, Tenaska will be responsible for the first $0.1 million of environmental claims, Tenaska and Puget Energy will share the next $6.4 million equally and Puget Energy will be responsible for the next $3.5 million. Puget Energy believes it will not have a future loss in connection with the environmental guarantee.

For the nine months ended September 30, 2006, Puget Energy reported InfrastruX related income from discontinued operations (net of taxes and minority interest), including gain on sale, of $51.9 million compared to $0.9 million (net of taxes and minority interest) for the nine months ended September 30, 2005. Puget Energy's income from discontinued operations for the nine months ended September 30, 2006 includes $7.3 million related to the reversal of a carrying value adjustment recorded in 2005 as well as $10.0 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."

	THREE MONTHS ENDED SEPTEMBER 30,		NINE MONTHS ENDED SEPTEMBER 30,	
(DOLLARS IN THOUSANDS)	2006	2005	2006	2005
Revenues	$ --	$ 111,667	$ 138,573	$ 286,665
Operating expenses (including interest expense)	--	(98,063)	(128,605)	(261,272)
Pre-tax income	--	13,604	9,968	25,393
Income tax expense	--	(4,684)	(3,544)	(8,637)
Puget Energy carrying value adjustment of InfrastruX	--	(8,094)	7,269	(13,204)
Puget Energy cost of sale related to InfrastruX, net of tax	--	(23)	(937)	(1,140)
Puget Energy deferred tax basis adjustment of InfrastruX	--	--	9,966	--
Gain on sale, net of tax	1	--	29,765	--
Minority interest in income of discontinued operations	--	(804)	(584)	(1,504)
Income (loss) from discontinued operations	$ 1	$ (1)	$ 51,903	$ 908

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 $4.7 million ($2.9 million after-tax) lower depreciation and amortization expense than otherwise would have been recorded as continuing operations for the three months ended September 30, 2005. Depreciation and amortization was $6.7 million ($4.3 million after-tax) and $12 million ($7.3 million after-tax) lower than otherwise would have been recorded as continuing operations for the nine months ended September 30, 2006 and 2005, respectively.

Puget Energy's balance sheet at September 30, 2006 does not include InfrastruX assets and liabilities as a result of the disposition in May 2006. InfrastruX's summarized assets and liabilities, including intercompany balances eliminated in consolidation, at December 31, 2005 were:

(DOLLARS IN THOUSANDS)	DECEMBER 31, 2005
Assets:	
Cash	$ 6,187
Accounts receivable	78,842
Other current assets	22,405
Total current assets	107,434
Goodwill	43,886
Intangibles	14,443
Non-utility property and other	108,784
Total long-term assets	167,113
Total assets	$ 274,547

(DOLLARS IN THOUSANDS)	DECEMBER 31, 2005
Liabilities:	
Accounts payable	$ 9,178
Short-term debt	3,809
Current maturities of long-term debt	6,477
Other current liabilities	36,327
Total current liabilities	55,791
Deferred income taxes	24,645
Long-term debt	120,013
Other deferred credits	16,986
Total long-term liabilities	161,644
Total liabilities	$ 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 116,101,000 and 115,910,000 for the three and nine months ended September 30, 2006, respectively, and 100,371,000 and 100,160,000 for the three and nine months ended September 30, 2005, respectively.

Puget Energy's diluted earnings per common share have been computed based on weighted average common shares outstanding of 116,568,000 and 116,311,000 for the three and nine months ended September 30, 2006, respectively, and 100,964,000 and 100,754,000 for the three and nine months ended September 30, 2005, respectively. 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 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 PSE deems 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 September 30, 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 September 30, 2006, the Company recorded an increase in earnings for the change in the market value of derivative instruments not meeting NPNS nor cash flow hedge criteria of approximately $0.6 million compared to a decrease in earnings of approximately $0.5 million for the three months ended September 30, 2005. At September 30, 2006, the Company had a net unrealized gain recorded in other comprehensive income of $5.5 million after-tax related to energy and financial contracts which meet the criteria for designation as cash flow hedges under SFAS No. 133. At September 30, 2006, PSE had a net short-term liability of $0.2 million related to non-cash flow hedges, as well as a net short-term liability of $1.4 million and a net long-term asset of $9.8 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.

During the nine months ended September 30, 2006, the Company recorded a decrease in earnings for the change in the market value of derivative instruments not meeting cash flow hedge criteria of approximately $0.2 million compared to a decrease in earnings of approximately $0.4 million for the nine months ended September 30, 2005.

At September 30, 2006, the Company also had a net short-term liability of approximately $65.4 million and a net long-term liability of $0.5 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 third quarter 2006, the Company settled two forward starting interest rate swap contracts originating in September 2006. The purpose of the forward starting swap contracts was to hedge interest rate volatility of a $300 million debt offering that was priced on September 13, 2006. Since interest rates decreased relative to the hedged rate, the debt was priced at a rate lower than the hedged rate. PSE paid $0.6 million to the counterparties when the contracts were settled. The forward starting swap contracts were designated and documented under SFAS No. 133 criteria as cash flow hedges, with all changes in market value presented net of tax in other comprehensive income. In accordance with SFAS No. 133, the loss will be amortized out of other comprehensive income to current earnings as an increase to interest expense over the life of the new debt issued. The ending balance in other comprehensive income related to the forward starting swaps and previously settled treasury lock contracts at September 30, 2006 was a loss of $8.6 million after-tax and accumulated amortization.

(5) Stock Compensation

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 No. 123R resulted in a cumulative benefit from an accounting change of $0.1 million, net of tax, for the quarter ended March 31, 2006. The cumulative effect adjustment is the result of the inclusion of estimated forfeitures occurring before award vesting dates in the computation of compensation expense for unvested awards.

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 nine months ended September 30, 2006, is $0.1 million and $0.1 million higher, respectively, than if it had continued to account for share-based compensation under SFAS No. 123 due to the inclusion of estimated forfeitures in compensation cost. There is no difference between basic and diluted earnings per share for income from continuing operations for the three and nine months ended September 30, 2006 under SFAS No. 123R as compared to earlier methods.

Had Puget Energy 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:

(Dollars in thousands, except per share amounts)	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2005
Net income, as reported	$ 5,911	$ 90,881
Add: Total stock-based employee compensation expense included in net income, net of tax	995	2,800
Less: Total stock-based employee compensation expense per the fair value method of SFAS No. 123, net of tax	(992)	(2,891)
Pro forma net income	$ 5,914	$ 90,790
Earnings per share:		
Basic per common share as reported	$ 0.06	$ 0.91
Diluted per common share as reported	$ 0.06	$ 0.90
Basic per common share pro forma	$ 0.06	$ 0.91
Diluted per common share pro forma	$ 0.06	$ 0.90

The Company's Long-Term Incentive Plan (LTI Plan), established in 1995 after approval by shareholders, 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 $(1.0) million and $1.1 million for the three months ended September 30, 2006 and 2005, respectively, and $(2.4) million and $3.1 million for the nine months ended September 30, 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 $22.52, $21.20, $19.70 and $16.92, respectively. There were a total of 152,254 performance awards granted for the 2006 cycle of which the company estimates a forfeiture rate of 10.1% or 15,378 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 September 30, 2006, there were four active grant cycles for a total of 854,387 share grants outstanding. As of December 31, 2005, there were four active grant cycles for a total of 907,983 share grants outstanding. As of September 30, 2006, there was $3.6 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 1.8 years. During the three and nine months ended September 30, 2006, 5,446 and 53,218 performance shares, respectively, were forfeited. No performance shares vested during the three or nine months ended September 30, 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 is classified and accounted for as a liability 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 that the quarterly expense recognized during the performance period is 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 September 30, 2006, with 270,000 options exercisable. At September 30, 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 immaterial to the financial statements for the three and nine months ended September 30, 2006. As of September 30, 2006, there was an immaterial amount 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 nine months ended September 30, 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 107,555 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 nine months ended September 30, 2006, 107,555 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 September 30, 2006, there were 209,222 total shares of nonvested restricted stock and the weighted average grant date fair value of these shares was $22.19. Compensation expense related to the restricted shares, including the restricted shares granted as part of the 2006 LTIP cycle, was $0.5 million and $0.2 million for the three months ended September 30, 2006 and 2005, respectively, and $1.5 million and $0.6 million for the nine months ended September 30, 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 $22.19 and $21.86, respectively. As of September 30, 2006, there was $2.2 million of total unrecognized compensation cost related to nonvested restricted stock. That cost is expected to be recognized over a weighted-average period of 1.8 years. During the three months ended September 30, 2006, 3,333 shares of restricted stock vested. Restricted stock forfeited during the three and nine months ended September 30, 2006 was 417 shares and 1,000 shares, respectively. No restricted stock vested or was forfeited during the three and nine months ended September 30, 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

In 2004, the Company 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 September 30, 2006, there were 10,000 total shares of nonvested restricted stock units and the weighted average fair value of these units was $22.73. There were no restricted stock units granted or forfeited during the three and nine months ended September 30, 2006 and 2005. 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 three and nine months ended September 30, 2006 and 2005. The weighted average grant date fair value for the restricted stock units was $23.55. As of September 30, 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 1.6 years. The fair value of the restricted stock units 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 under 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 September 30, 2006, there were 5,966 total shares of nonvested retirement equivalent stock units and the weighted average grant date fair value of these units was $22.71. During the nine months ended September 30, 2006, 8,218 retirement equivalent stock units were granted. The equivalent value of dividends is paid on the accumulated retirement equivalent stock units and added to the deferred compensation account. Compensation expense related to the retirement equivalent stock agreement was immaterial to the financial statements. 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 September 30, 2006, there was an immaterial amount of unrecognized compensation cost related to nonvested retirement equivalent stock units. That cost is expected to be recognized over a weighted-average period of 1.7 years. During the three and nine months ended September 30, 2006, 778 and 7,265 retirement equivalent stock units vested, respectively. No retirement equivalent stock units were forfeited during the quarter ended September 30, 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 September 30, 2006, 117,393 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, the ESPP is considered to be compensatory and the amount is immaterial to the financial statements. Purchase rights to 35,654 shares were granted for the three months ended September 30, 2006 and 31,421 new shares were issued for the nine months ended September 30, 2006. Purchase rights to 30,849 shares were granted for the three months ended September 30, 2005 and 23,048 new shares were issued for the nine months ended September 30, 2005. Dividends are not paid on ESPP shares until they are purchased by employees and thus are accounted for as dividends, not compensation expense.

NON-EMPLOYEE DIRECTOR STOCK PLAN

The Company has a director stock plan for all non-employee directors of Puget Energy and PSE. An amended and restated plan was 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 choose to continue to receive their entire retainer in Puget Energy stock. The compensation expense related to the director stock plan was $0.1 million and $0.1 million for the three months ended September 30, 2006 and 2005, respectively, and $0.3 million and $0.3 million for the nine months ended September 30, 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 September 30, 2006, 33,185 shares had been issued or purchased for the director stock plan and 88,313 deferred, for a total of 121,498 shares. As of September 30, 2005, the number of shares that had been purchased for the director stock plan was 22,986 and deferred was 73,836, for a total of 96,822 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	*	*	*	*	4.5
Expected stock volatility	*	*	*	*	23.62%
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	4.96%	2.68%	1.28%	1.07%	*
Expected lives – years	0.5	0.5	0.5	0.5	*
Expected stock volatility	9.79%	13.98%	9.89%	19.47%	*
Dividend yield	4.55%	4.17%	4.42%	4.39%	*

* *Not applicable*

** *Fair value is determined by end of period market value.*

The expected lives of the securities represent 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 September 30:

	Pension Benefits		Other Benefits	
(Dollars in thousands)	2006	2005	2006	2005
Service cost	$ 3,293	$ 2,887	$ 99	$ 77
Interest cost	6,171	5,964	426	359
Expected return on plan assets	(9,310)	(9,482)	(290)	(220)
Amortization of prior service cost	585	717	134	116
Recognized net actuarial (gain) loss	1,423	839	49	(140)
Amortization of transition (asset) obligation	--	(41)	104	105
Net periodic benefit cost	$ 2,162	$ 884	$ 522	$ 297

The following summarizes the net periodic benefit cost for the nine months ended September 30:

	Pension Benefits		Other Benefits	
(Dollars in thousands)	2006	2005	2006	2005
Service cost	$ 9,415	$ 8,662	$ 270	$ 229
Interest cost	18,501	17,891	1,142	1,056
Expected return on plan assets	(28,179)	(28,446)	(653)	(659)
Amortization of prior service cost	1,756	2,150	401	349
Recognized net actuarial (gain) loss	3,922	2,516	(205)	(458)
Amortization of transition (asset) obligation	--	(122)	314	314
Net periodic benefit cost	$ 5,415	$ 2,651	$ 1,269	$ 831

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 and nine months ended September 30, 2006, the actual cash contributions to the pension plans were $0.4 million and $2.6 million, respectively. Based on this activity, the Company anticipates contributing an additional $0.9 million to the Company's non-qualified 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 and nine months ended September 30, 2006, actual other post-retirement medical benefit plan contributions were less than $0.1 million and $0.7 million, respectively, and the Company does not expect to make additional contributions for the remaining period of 2006. The total contributions for 2006 will be $0.7 million.

On September 29, 2006, Financial Accounting Standards Board (FASB) issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans." SFAS No. 158 is effective for fiscal years ending after December 15, 2006, which will be the year ended December 31, 2006, for the Company. SFAS No. 158 will be adopted prospectively, as required by the statement. SFAS No. 158 requires 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 projected benefit obligation. At December 31, 2005, the combined fair value of plan assets and projected benefit obligation for the Company's defined benefit pension and the retiree medical and life plans was $481.0 million and $439.0 million, respectively. At September 30, 2006, the Company estimates that upon adoption of the standard, it will record a pre-tax charge to Accumulated Other Comprehensive Income of approximately $64.0 million, a reduction of approximately $54.0 million to the pension plan prepaid asset and an increase of approximately $10.0 million to benefit plan liabilities. Actual return on plan assets for the fourth quarter 2006 could influence these estimates.

(7) Regulation and Rates

On September 27, 2006, the Washington Commission approved a revision of PSE's Purchased Gas Adjustment (PGA) tariff schedule that went into effect on October 1, 2006. The tariff changes will increase gas revenue approximately $95.1 million, or 9.9%, on an annual basis. The rate increase authorized PSE to recover higher projected future gas and gas transportation costs, as well as to collect the accumulated PGA receivable balance over a 24-month period (beginning October 1, 2006). The PGA rate change will increase PSE's gas revenue, but will not impact the Company's net income as the increased revenue will be offset by increased purchased gas costs. 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 gas prices.

On July 10, 2006, PSE reduced its gas general rate increase request filed with the Washington Commission on February 15, 2006 from $40.4 million to $39.2 million, or 4.2%, on an annual basis. On September 15, 2006, the Company adjusted the requested general rate increase to $38.9 million annually. PSE also has requested approval of a new depreciation tracker in its original gas general rate case filing to recover increases in gas distribution depreciation costs incurred between general rate cases of $10.9 million. In addition, a gas decoupling mechanism, which does not have an impact on the current rate increase, was requested; however, it is designed to stabilize revenue changes due to load variations between regulatory filings. The resolution of the general rate case is expected by the end of 2006.

On September 27, 2006, the Washington Commission approved a revision of PSE's electric rate tariff Schedule 94 "Residential and Farm Exchange Benefit" that became effective October 1, 2006. The Schedule 94 credit rate was reduced from $0.01740 to $0.01028 per kWh, reflecting a reduction in the annual estimated value of the BPA Residential Exchange benefits from $174.4 million to $105.0 million, beginning October 1, 2006. This tariff revision will have the impact of increasing PSE electric customer revenues, but will not impact PSE net income. Under Federal law, BPA is required to provide benefits from the low-cost federal power system to residential and small farm customers served by investor-owned utilities in the Northwest. All benefits received by an investor-owned utility must be passed on to its residential and small farm customers.

On June 28, 2006, the Washington Commission approved a 5.9%, or $45.3 million, Power Cost Only Rate Case (PCORC) increase in electric rates for the period July 1, 2006 through December 31, 2006. The increase allows PSE to recover higher projected costs of power caused primarily by higher market prices for natural gas used as fuel for electric generators. The rate increase will not appreciatively impact PSE's income. The annualized basis of the PCORC rate increase when applied to the general rate case test year is $96.1 million. Primarily as a result of this order, on July 10, 2006, PSE reduced its pending electric general tariff increase from $140.9 million to $42.9 million, or 2.5%, on an annualized basis. On September 15, 2006, the Company adjusted the requested increase to $33.5 million annually. Additionally, PSE has requested approval of a new tariff in its original general rate case filing to recover increases in electric transmission and distribution depreciation costs incurred between general rate cases of $7.9 million. The resolution of the general rate case is expected by the end of 2006.

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 $89.0 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 the payment as a regulatory asset with accrual of carrying costs 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 carrying costs on a temporary basis until resolution of PSE's electric general rate case later this year.

At September 30, 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 Corporation (California PX). In August 2005, PSE submitted its audited Fuel Cost Allowance Claim with the CAISO. That claim was challenged by the California Parties, but on August 23, 2006, FERC issued an order approving PSE's Fuel Cost Allowance Claim. In addition, PSE filed a portfolio cost claim, and 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 stated claim. PSE does not agree with all of FERC's rulings and sought rehearing, which is still pending at FERC. PSE's ability to recover all or a portion of these claims is uncertain at the present time.

In addition, on August 2, 2006, the United States Court of Appeals for the Ninth Circuit issued a decision in *CPUC v. FERC* regarding the scope of refunds and the transactions subject to refunds, and ordered the matter remanded to FERC for further proceedings. The August 2, 2006 decision, discussed below at "Proceedings Relating to the Western Power Market," may adversely impact PSE's ability to recover the full amount of its CAISO Receivable. As a result of the August 2, 2006 decision, PSE cannot assess the ultimate resolution of its California Receivable. Accordingly, PSE has estimated a range related to its CAISO receivable to be between $21.2 million (PSE's net receivable balance) and $29.5 million, including interest, on its past due receivables as of September 30, 2006. As a result of the Ninth Circuit decision of August 2, 2006, PSE cannot assess the ultimate resolution of its California Receivable. At this time there is no reasonable basis to adjust PSE's receivable balance of $21.2 million because the procedural outcome of a rehearing or remand to FERC is uncertain and any financial impact cannot be quantified.

(8) Litigation and Contingencies

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 agreements, including the amended settlement agreement (and the May 2004 agreement) between BPA and PSE regarding the BPA Residential Purchase and Sale Program. BPA rates used in such agreements between BPA and PSE for determining the amounts of money to be paid to PSE by BPA under such agreements 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 or early 2007. A number of parties have claimed that the BPA rates proposed or adopted in the BPA rate proceeding to develop BPA rates to be used in the agreements for determining the amounts of money to be paid to PSE by BPA during the period October 1, 2006 through September 30, 2009 are contrary to law and that BPA acted contrary to law or without authority in deciding to enter into, or in entering into or performing or implementing such agreements. It is not clear what impact, if any, development or review of such rates, review of such agreements and the above described U.S. Ninth Circuit Court of Appeals actions may have on PSE.

On April 29, 2004, the Minerals Management Service of the United States Department of the Interior (MMS) issued an order to Western Energy Company (WECO) to pay additional royalties concerning coal purchased by PSE for Colstrip Units 3 & 4. The order seeks payment of an additional $1.1 million in royalties for coal mined from federal land between April 1997 and June 30, 2000. During that period, PSE's coal price was reduced by a settlement agreement entered into in February 1997 among PSE, WECO and Montana Power Company that resolved disputes that were then pending. The order seeks to impute the price charged to PSE based on the other Colstrip Units 3 & 4 owners' contractual amounts. PSE is supporting WECO's appeal of the order. In addition, the State of Montana issued a demand to WECO based upon an audit in May 2005 for allegedly unpaid royalties, asserting this same theory. The amount claimed in that demand is $0.2 million. PSE accrued a loss reserve in the amount of $1.1 million in connection with this matter in the second quarter 2004 and updated that amount to $1.8 million in the third quarter 2006.

In addition, the MMS issued two orders to WECO in 2002 and 2003 to pay additional royalties concerning coal sold to Colstrip Units 3 & 4 owners. The orders assert that additional royalties are owed as a result of WECO not paying royalties in connection with revenue received by WECO from the Colstrip Units 3 & 4 owners under a coal transportation agreement during the period October 1, 1991 through December 31, 2001. On April 28, 2005, the appeals division of the MMS issued an order that reduced the amount claimed due to the application of statute of limitations. PSE's share of the alleged additional royalties is approximately $1.7 million, which is equivalent to PSE's 25% ownership interest in Colstrip Units 3 & 4. The state of Montana issued a demand to WECO in May 2005 consistent with the MMS position outlined above on these transportation revenues. The state's position, if correct, would result in an additional $0.1 million claim against PSE. The transportation agreement provides for the construction and operation of a conveyor system that runs several miles from the mine to Colstrip Units 3 & 4. WECO has appealed these orders and PSE is monitoring the process. PSE believes that the Colstrip Units 3 & 4 owners have reasonable defenses in this matter based upon its review. However, if the MMS position prevails, this issue could create ongoing expenses as the conveyor system continues to be used. Further, on September 28, 2006, the MMS issued an order to pay additional royalties in the amount of $1.5 million on the basis of an audit of WECO's royalty payments during the three years 2002 to 2004 and that applies the same theory to the transportation revenues. PSE's share of that claim is approximately $0.4 million based upon PSE's ownership of the projects. If litigated, this claim would follow the same process as the two already pending, involving a multiple-layer appellate process before a final decision. It is likely that any result would be substantially identical to the resolution on the two periods already pending.

(9) Related Party Transaction

During the nine months ended September 30, 2006, Puget Energy established the Puget Sound Energy Foundation (Foundation) with a $15.0 million contribution to the Foundation from a portion of the proceeds from the sale of InfrastruX. The contribution was recorded as other income (deduction) expense. The Foundation was established by Puget Energy as a not-for-profit organization whose results are not consolidated by Puget Energy.

On June 1, 2006, PSE entered into a revolving credit facility with its parent, Puget Energy, in the form of a Demand Promissory Note (Note). Through the Note, PSE may borrow up to $30.0 million from Puget Energy, subject to approval by Puget Energy. Under the terms of the Note, PSE pays interest on the outstanding borrowings based on the lowest of the weighted average interest rate of (a) PSE's outstanding commercial paper interest rate; (b) PSE's senior unsecured revolving credit facility; or (c) the interest rate available under the receivable securitization facility of PSE Funding, Inc., a PSE subsidiary, which is the LIBOR rate plus a marginal rate. At September 30, 2006, the outstanding balance of the Note was $24.2 million. The outstanding balance and the related interest under the Note are eliminated by Puget Energy upon consolidation of PSE's financial statements.

(10) Financings

On September 18, 2006, PSE completed the issuance of $300 million of senior secured notes at a rate of 6.274%, which are due on March 15, 2037. The net proceeds from the issuance of the senior notes of approximately $297.4 million were used to repay PSE's outstanding short-term debt which was incurred primarily to fund construction programs. The yield to maturity of the $300 million senior secured notes was 6.29% after the settlement of two forward starting swap interest rate contracts.

On June 30, 2006, PSE redeemed for $200 million all of the outstanding shares of the 8.40% Trust Originated Preferred Securities of the Puget Sound Energy Capital Trust II (classified as Junior Subordinated Debentures of the Corporation Payable to a Subsidiary Trust Holding Mandatorily Redeemable Preferred Securities on the balance sheet) at $25 par value per share plus accrued interest to the redemption date.

On June 30, 2006, PSE completed the issuance of $250 million of senior secured notes at a rate of 6.724%, which are due on June 15, 2036. The net proceeds from the issuance of the senior notes of approximately $247.8 million were used to redeem $200 million of 8.40% Capital Trust Preferred Securities, which were redeemed at par on June 30, 2006, and to repay a portion of PSE's short-term debt. The short-term debt was incurred to repay $46 million of 8.06% senior notes that matured June 19, 2006. The yield to maturity of the $250 million senior secured notes was 6.17% after the settlement of two forward starting swap interest rate contracts.

(11) Other

PSE leases the Whitehorn power generating facility, a 147 MW net capacity dual-fuel combustion turbine, under a noncancelable operating lease expiring in February 2009. PSE entered into an agreement on October 17, 2006 with the lessor under which PSE agreed to purchase the generation facilities after the lease term expires in February 2009, provided that all conditions precedent are satisfied or waived. In the fourth quarter 2006, the lease will be treated as a capital lease over its remaining lease period.

In January 2003, 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 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 September 30, 2006 and 2005 for these three entities was $78.8 million and $73.2 million, respectively. PSE's purchased electricity expense for the nine months ended September 30, 2006 and 2005 for these three entities was $174.7 million and $186.7 million, respectively.

The US Environmental Protection Agency requires states to produce regulations by November 15, 2006 that will bring their mercury emissions in line with those mandated by the Clean Air Mercury Rule (CAMR). The Montana Board of Environmental Review approved the state's regulation to limit mercury emissions from coal-fired plants on October 16, 2006. The new rule takes a two-tiered approach to reducing mercury emissions, allowing power plants burning lower-quality lignite coal to release more emissions than plants burning cleaner sub-bituminous coal, such as Colstrip. The new rule has a more stringent limit than the federal rule (0.9 lbs/Trillion British thermal unit (TBtu), instead of the federal 1.4 lbs/TBtu), but includes a cap-and-trade provision as well as alternative emission limits for plants that have tried to meet the new standards but have demonstrated that they cannot. The Colstrip owners are still evaluating the potential impact of the new rule and it is still unknown whether the new rule will be appealed.

(12) New Accounting Pronouncements

At its June 15, 2006 meeting, FASB's Emerging Issues Task Force (EITF) approved the issuance of EITF Issue No. 06-3, "How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation)." EITF No. 06-3 will require disclosure whether or not the taxes collected from customers and remitted to government authorities are reported on a gross (included in revenues and costs) or a net (excluded from revenues) basis. In addition, for any such taxes that are reported on a gross basis, a company should disclose the amounts of those taxes in interim and annual financial statements for each period for which an income statement is presented if those amounts are significant. The EITF concluded that these requirements should be applied to financial reports for interim and annual periods beginning after December 15, 2006, which will be the quarter ended March 31, 2007, for the Company. PSE collected Washington State excise taxes (which are a component of general retail rates) and municipal taxes of $35.9 million and $141.2 million for the three and nine months ended September 30, 2006, respectively, and $31.7 million and $122.6 million for the three and nine months ended September 30, 2005, respectively. The Company's policy is to report such taxes on a gross basis in operating revenues and taxes other than income taxes in the accompanying consolidated statements of income.

In July 2006, FASB issued Interpretation No. 48 (FIN 48), "Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109", which clarifies the accounting for uncertainty in income taxes recognized in the financial statements in accordance with FASB Statement No. 109, "Accounting for Income Taxes." FIN 48 provides guidance on recognition threshold and measurement attributed to a tax position taken or expected to be taken in a tax return. The tax positions should only be recognized when it is more likely than not, based on technical merits, that the position will be sustained upon examination by the taxing authority. FIN 48 is effective for fiscal years beginning after December 15, 2006, which will be the quarter ended March 31, 2007 for the Company. The Company is currently evaluating the provisions of FIN 48 to determine the potential impact, if any, the adoption will have on the Company's financial statements.

On September 15, 2006, FASB issued SFAS No. 157, "Fair Value Measurements." SFAS No. 157 standardizes the measurement of fair value when it is required under generally accepted accounting principles (GAAP). SFAS No. 157 is effective for fiscal years beginning after November 15, 2007, which will be the year beginning January 1, 2008, for the Company. The adoption of SFAS No. 157 is not expected to have a material impact on the Company's financial statements.

On September 29, 2006, FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans." See Note 6, "Retirement Benefits" for discussion of the new statement.

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 subsidiary Puget Sound Energy (PSE), a regulated electric and gas utility company, and until May 7, 2006, InfrastruX Group, Inc. (InfrastruX). Puget Energy owned a 90.9% interest in InfrastruX, a utility construction and services company, until it was sold to an affiliate of Tenaska Power Fund, L.P. on May 7, 2006. After repayment of debt, adjustments for working capital, transaction costs and distributions to minority interests, Puget Energy received $95.9 million for its 90.9% interest in InfrastruX in the second quarter 2006. The sale resulted in an after-tax gain of $29.8 million for the nine months ended September 30, 2006. Puget Energy accounted for InfrastruX as a discontinued operation under Statement of Financial Accounting Standards (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" in 2005 and 2006. See section titled "InfrastruX" for further discussion. The $95.9 million net proceeds Puget Energy received from the sale of InfrastruX were used to support PSE through an equity contribution of $65.0 million and a loan of $24.2 million. In addition, Puget Energy established a charitable foundation, Puget Sound Energy Foundation (Foundation), in the second quarter 2006 with a contribution of $15.0 million from the net proceeds from the sale of InfrastruX along with investment income of $0.4 million on the cash proceeds and a federal income tax benefit of $5.3 million from funding the Puget Sound Energy Foundation.

PUGET SOUND ENERGY

PSE generates revenues from the sale of electric and gas services, mainly to residential and commercial customers within Washington State. Variations in energy usage by customers occur from season to season primarily as a result of weather conditions. PSE normally experiences higher retail energy sales and subsequently higher power costs during the winter heating season in the first and fourth quarters of the year and its lowest sales in the third quarter of the year.

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 gas and 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 is implementing a strategy to be more self-sufficient in energy generation resources. PSE is continually exploring 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 in the fourth quarter 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.

In August 2006, PSE announced the selection of seven projects for further discussion and possible negotiation as a result of the 2005 RFP process. In aggregate, these outside sources, if completed, would generate approximately 1,100 megawatts (MW) of long-term power supply in total. The outcome of such discussion and negotiation cannot now be determined.

Results of Operations

PUGET ENERGY

All the operations of Puget Energy are conducted through PSE and until May 7, 2006, InfrastruX. Net income for the three months ended September 30, 2006 was $15.9 million on operating revenues from continuing operations of $519.5 million compared to net income of $5.9 million on operating revenues from continuing operations of $490.4 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 September 30, 2006 were $0.14 compared to basic and diluted earnings per share for the three months ended September 30, 2005 of $0.06. The discontinued operations of InfrastruX had no impact on the basic and diluted earnings per share for the three months ended September 30, 2006 and 2005.

Net income for the three months ended September 30, 2006 was positively impacted by increased electric margins of $22.2 million compared to the same period in 2005 primarily from increased sales volumes and overrecovery of power costs under the Power Cost Adjustment (PCA) mechanism. Higher electric margins were also the result of two Power Cost Only Rate Cases (PCORC) effective November 1, 2005 and July 1, 2006 which increased rates by 3.65% and 5.9%, respectively. The overrecovery of power costs in the third quarter is seasonal as power costs are normally below the benchmark rate set in the PCA mechanism. PSE expects to underrecover in the fourth quarter 2006 as power costs are likely to exceed the benchmark rate set in the PCA mechanism. The increase in electric margin was offset by an increase of $6.0 million related to utility operation and maintenance expense and a $5.0 million increase in depreciation and amortization expense of which $2.3 million is related to Hopkins Ridge which is recovered in electric rates.

For the nine months ended September 30, 2006, Puget Energy's net income was $162.1 million on operating revenues from continuing operations of $2.0 billion compared to net income of $90.9 million on operating revenues from continuing operations of $1.7 billion for the same period in 2005. Basic earnings per share for the nine months ended September 30, 2006 was $1.40 compared to basic earnings per share of $0.91 for the same period in 2005 and diluted earnings per share for the nine months ended September 30, 2006 was $1.39 compared to basic and diluted earnings per share of $0.90 for the same period in 2005. Included in the basic earnings per share for the nine months ended September 30, 2006 and 2005 was $0.45 and $0.01 respectively, earnings per share related to discontinued operations of InfrastruX. Included in the diluted earnings per share for the nine months ended September 30, 2006 and 2005 was $0.44 and $0.01 respectively, earnings per share related to discontinued operations of InfrastruX.

Net income for the nine months ended September 30, 2006 was positively impacted by income from discontinued operations of InfrastruX of $51.9 million (after-tax) compared to $0.9 million (after-tax) for the nine months ended September 30, 2005. The income from discontinued operations for the nine months ended September 30, 2006 includes a gain on disposal of $29.8 million (after-tax) resulting from the sale of InfrastruX. The reversal of an InfrastruX carrying value charge recognized in 2005 of $7.3 million contributed to the gain on disposal as well as $10.0 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." Natural gas and electric margins increased by $18.7 million and $44.2 million, respectively, for the nine months ended September 30, 2006 compared to the same period in 2005, which positively impacted net income. The increase in natural gas margins resulted from increased natural gas general tariff rates, increased sales volumes and the non-occurrence of a purchased gas true-up of previously reported gas costs in 2005 of $4.5 million. The increase in electric margins was the result of increased sales volumes, overrecovery of power costs under the PCA mechanism and two PCORC rate increases effective November 1, 2005 and July 1, 2006. The overrecovery of power costs in the third quarter is seasonal as power costs are normally below the benchmark rate set in the PCA mechanism. PSE expects to underrecover in the fourth quarter 2006 as power costs will exceed the benchmark set in the PCA mechanism. Income from continuing operations was $119.9 million for the nine months ended September 30, 2006, excluding the impact of the charitable contribution to the Foundation. Management of the Company believes it is useful to present income from continuing operations and diluted earnings excluding the impact of the charitable contribution because it represents a more accurate measure of operating performance and facilitates period-to-period comparisons. Basic and diluted earnings per share from continuing operations were $1.03 for the nine months ended September 30, 2006, excluding the impact of the charitable contribution to the Foundation. A reconciliation to amounts under generally accepted accounting principles is as follows:

(Dollars in millions, except per share amounts)	Nine Months Ended September 30, 2006
Income from continuing operations, as reported	$ 110.1
Add: Impact of charitable contribution to Foundation, net of tax	9.8
Income from continuing operations, excluding charitable contribution	$ 119.9
Earnings per share:	
Basic and diluted earnings per share before cumulative effect of accounting change from continuing operations, as reported	$ 0.95
Add: Impact of charitable contribution to Foundation	0.08
Basic and diluted earnings per share before cumulative effect of accounting change from continuing operations, excluding charitable contribution	$ 1.03

Puget Sound Energy

PSE's operating revenues and associated expenses are not generated evenly during the year. Variations in energy usage by customers 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 and subsequently higher power costs during the winter 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 September 30, 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 SEPTEMBER 30,	ELECTRIC MARGIN 2006	2005	CHANGE	PERCENT CHANGE
Electric retail sales revenue	$ 363.3	$ 315.3	$ 48.0	15.2 %
Electric transportation revenue	3.4	1.7	1.7	100.0 %
Other electric revenue-gas supply resale	(0.1)	9.1	(9.2)	(101.1)%
Total electric revenue for margin[1]	366.6	326.1	40.5	12.4 %
Adjustments for amounts included in revenue:				
Production tax credits (PTCs)	3.1	--	3.1	*
Pass-through tariff items	(8.3)	(6.5)	(1.8)	(27.7)%
Pass-through revenue-sensitive taxes	(26.7)	(23.2)	(3.5)	(15.1)%
Residential exchange credit	35.9	34.5	1.4	4.1 %
Net electric revenue for margin	370.6	330.9	39.7	12.0 %
Minus power costs:				
Electric generation fuel	(36.3)	(21.1)	(15.2)	(72.0)%
Purchased electricity, net of sales to other utilities and marketers[2]	(155.5)	(160.2)	4.7	2.9 %
Total electric power costs[3]	(191.8)	(181.3)	(10.5)	(5.8)%
Electric margin before PCA	178.8	149.6	29.2	19.5 %
Tenaska disallowance reserve	(3.9)	--	(3.9)	*
Electric margin before PTCs revenue credit [4]	174.9	149.6	25.3	16.9 %
Production tax credits revenue reduction	(3.1)	--	(3.1)	*
Electric margin including PTCs revenue credit [4]	$ 171.8	$ 149.6	$ 22.2	14.8 %

* *Percent change not applicable or meaningful.*

1 *For the three months ended September 30, 2006, total electric revenue for margin was $366.6 million, which does not include $24.3 million in sales to other utilities and marketers and $8.3 million in other miscellaneous electric revenue included in electric operating revenues of $399.2 million. For the three months ended September 30, 2005, total electric revenue for margin was $326.1 million, which does not include $40.6 million in sales to other utilities and marketers and $8.3 million in other miscellaneous electric revenues included in electric operating revenues of $375.0 million.*

2 *For the three months ended September 30, 2006, purchased electricity, net of sales to other utilities and marketers, was $155.5 million, excluding sales to other utilities and marketers of $24.3 million and including power cost deferral under the PCA mechanism of $3.9 million, purchased electricity was $183.7 million. For the three months ended September 30, 2005, purchased electricity, net of sales to other utilities and marketers, was $160.2 million, excluding sales to other utilities and marketers of $40.7 million, purchased electricity was $200.9 million.*

3 *For the three months ended September 30, 2006, total electric power costs were $191.8 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 $(35.9) million, unrealized net gain on derivative instruments of $(0.6) million and power cost deferral of $3.9 million. These amounts, excluding sales of electricity to other utilities and marketers, provide electric energy costs of $183.5 million. For the three months ended September 30, 2005, total electric power costs were $181.3 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 $(34.5) 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 $187.9 million.*

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

Electric margin increased $22.2 million for the three months ended September 30, 2006 compared to the same period in 2005 primarily due to overrecovery of power costs under the PCA mechanism which increased margin by $12.2 million. Retail customer kWh sales (residential, commercial and industrial customers) increased 3.4% for the three months ended September 30, 2006 compared to 2005, which provided $5.4 million to electric margin. In addition, electric margin increased by $7.7 million as a result of the effects of the PCORC rate increases effective November 1, 2005 and July 1, 2006. These amounts were offset by a $3.1 million decrease related to production tax credits (PTCs), which are federal income tax credits received for wind generation, provided to customers through tariff rates.

The overrecovery of power costs in the third quarter is seasonal as power costs are normally below the benchmark rate set in the PCA mechanism. PSE expects to underrecover in the fourth quarter 2006 as power costs are likely to exceed the benchmark rate set in the PCA mechanism.

The following table displays the details of electric margin changes for the nine months ended September 30, 2006 compared to the same period in 2005.

(Dollars in Millions) Nine Months Ended September 30,	Electric Margin 2006	2005	Change	Percent Change
Electric retail sales revenue	$ 1,143.7	$ 1,018.9	$ 124.8	12.2 %
Electric transportation revenue	8.8	6.7	2.1	31.3 %
Other electric revenue-gas supply resale	11.9	14.3	(2.4)	(16.8)%
Total electric revenue for margin[1]	1,164.4	1,039.9	124.5	12.0 %
Adjustments for amounts included in revenue:				
Production tax credits (PTCs)	10.0	--	10.0	*
Pass-through tariff items	(25.4)	(19.0)	(6.4)	(33.7)%
Pass-through revenue-sensitive taxes	(83.4)	(75.4)	(8.0)	(10.6)%
Residential exchange credit	131.2	126.7	4.5	3.6 %
Net electric revenue for margin	1,196.8	1,072.2	124.6	11.6 %
Minus power costs:				
Electric generation fuel	(72.1)	(54.4)	(17.7)	(32.5)%
Purchased electricity, net of sales to other utilities and marketers[2]	(550.4)	(522.5)	(27.9)	(5.3)%
Total electric power costs[3]	(622.5)	(576.9)	(45.6)	(7.9)%
Electric margin before PCA	574.3	495.3	79.0	16.0 %
Tenaska disallowance reserve	--	5.3	(5.3)	*
Power cost deferred under the PCA mechanism	(16.5)	3.0	(19.5)	*
Electric margin before PTCs revenue credit [4]	557.8	503.6	54.2	10.8 %
Production tax credits revenue reduction	(10.0)	--	(10.0)	*
Electric margin including PTC revenue credit [4]	$ 547.8	$ 503.6	$ 44.2	8.8 %

* *Percent change not applicable or meaningful.*

1 *For the nine months ended September 30, 2006, total electric revenue for margin was $1,164.4 million, which does not include $56.9 million in sales to other utilities and marketers and $26.3 million in other miscellaneous electric revenue included in electric operating revenues of $1,247.6 million. For the nine months ended September 30, 2005, total electric revenue for margin was $1,039.9 million, which does not include $73.8 million in sales to other utilities and marketers and $26.8 million in other miscellaneous electric revenues included in electric operating revenues of $1,140.5 million.*

2 *For the nine months ended September 30, 2006, purchased electricity, net of sales to other utilities and marketers, was $550.4 million. Excluding sales to other utilities and marketers of $56.9 million and including power cost deferral under the PCA mechanism of $16.5 million, purchased electricity was $623.8 million. For the nine months ended September 30, 2005, purchased electricity, net of sales to other utilities and marketers, was $522.5 million, excluding sales to other utilities and marketers of $73.8 million and including the Tenaska disallowance reserve turnaround of $(5.3) million and power cost deferral under the PCA mechanism of $(3.0) million, purchased electricity was $588.0 million.*

3 *For the nine months ended September 30, 2006, total electric power costs were $622.5 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 $(131.2) million, unrealized net loss on derivative instruments of $0.2 million and power cost deferral of $16.5 million. These amounts, excluding sales of electricity to other utilities and marketers, provide electric energy costs of $564.9 million. For the nine months ended September 30, 2005, total electric power costs were $576.9 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 $(126.7) million, unrealized net loss on derivative instruments of $0.4 million and including the Tenaska disallowance reserve turnaround of $(5.3) million and power cost deferral under the PCA mechanism of $(3.0) million. These amounts, excluding sales of electricity to other utilities and marketers, provide electric energy costs of $516.1 million.*

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

Electric margin increased $44.2 million for the nine months ended September 30, 2006 compared to the same period in 2005 primarily due to overrecovery of power costs under the PCA mechanism which increased margin by $23.2 million. Retail customer kWh sales (residential, commercial and industrial customers) increased 3.8% for the nine months ended September 30, 2006 compared to 2005, which provided $19.4 million to electric margin. Electric margin increased as a result of the effects of the PCORC rate increases effective November 1, 2005, and July 1, 2006, which increased margin by $16.6 million. In addition, the reduction in the Tenaska disallowance in the PCA mechanism provided $1.0 million to margin. These increases were partially offset by a $10.0 million decrease related to PTCs provided to customers through tariff rates and 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.

The overrecovery of power costs in the third quarter is seasonal as power costs are normally below the benchmark rate set in the PCA mechanism. PSE expects to underrecover in the fourth quarter 2006 as power costs are likely to exceed the benchmark rate set in the PCA mechanism.

The following table displays the details of gas margin changes for the three months ended September 30, 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.

(DOLLARS IN MILLIONS) THREE MONTHS ENDED SEPTEMBER 30,	GAS MARGIN 2006	2005	CHANGE	PERCENT CHANGE
Gas retail revenue	$ 112.7	$ 103.8	$ 8.9	8.6 %
Gas transportation revenue	3.1	3.3	(0.2)	(6.1) %
Total gas revenue for margin[1]	115.8	107.1	8.7	8.1 %
Adjustments for amounts included in revenue:				
Pass-through tariff items	(0.7)	(0.6)	(0.1)	(16.7) %
Pass-through revenue-sensitive taxes	(9.2)	(8.4)	(0.8)	(9.5) %
Net gas revenue for margin	105.9	98.1	7.8	8.0 %
Minus purchased gas costs	(68.3)	(59.2)	(9.1)	(15.4) %
Gas margin[2]	$ 37.6	$ 38.9	$ (1.3)	(3.3) %

1 *For the three months ended September 30, 2006, total gas revenue for margin was $115.8 million, which does not include $3.8 million related to other gas operating revenues that is included in gas operating revenues of $119.6 million. For the three months ended September 30, 2005, total gas revenue for margin was $107.1 million, which does not include $3.9 million related to other gas operating revenues that is included in gas operating revenues of $111.0 million.*

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

Gas margin decreased $1.3 million for the three months ended September 30, 2006 compared to the same period in 2005 primarily due to a 1.2% decline in therm sale volumes and customer mix volumes.

The following table displays the details of gas margin changes for the nine months ended September 30, 2006 compared to the same period in 2005.

(DOLLARS IN MILLIONS) NINE MONTHS ENDED SEPTEMBER 30,	GAS MARGIN 2006	2005	CHANGE	PERCENT CHANGE
Gas retail revenue	$ 696.4	$ 571.8	$ 124.6	21.8 %
Gas transportation revenue	9.8	9.9	(0.1)	(1.0) %
Total gas revenue for margin[1]	706.2	581.7	124.5	21.4 %
Adjustments for amounts included in revenue:				
Pass-through tariff items	(4.5)	(3.5)	(1.0)	(28.6) %
Pass-through revenue-sensitive taxes	(57.7)	(47.2)	(10.5)	(22.2) %
Net gas revenue for margin	644.0	531.0	113.0	21.3 %
Minus purchased gas costs	(453.3)	(359.0)	(94.3)	(26.3) %
Gas margin[2]	$ 190.7	$ 172.0	$ 18.7	10.9 %

1 *For the nine months ended September 30, 2006, total gas revenue for margin was $706.2 million, which does not include $12.4 million related to other gas operating revenues that is included in gas operating revenues of $718.6 million. For the nine months ended September 30, 2005, total gas revenue for margin was $581.7 million, which does not include $13.0 million related to other gas operating revenues that is included in gas operating revenues of $594.7 million.*

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

Gas margin increased $18.7 million for the nine months ended September 30, 2006 compared to the same period in 2005. Gas margin increased $10.0 million due to a 5.6% increase in gas therm volume sales, $7.0 million of the increase was a result of the gas general tariff rate case which was effective March 4, 2005 and $4.5 million of the increase was due to the one-time true-up of previously reported gas costs in the second quarter 2005. These increases were partially offset by a $2.8 million decrease in margin related to customer mix and pricing.

ELECTRIC OPERATING REVENUES

The table below sets forth changes in electric operating revenues for PSE for the three months ended September 30, 2006 compared to the same period in 2005.

(DOLLARS IN MILLIONS) THREE MONTHS ENDED SEPTEMBER 30,	2006	2005	CHANGE	PERCENT CHANGE
Electric operating revenues:				
Residential sales	$ 150.2	$ 131.7	$ 18.5	14.0 %
Commercial sales	174.7	153.1	21.6	14.1 %
Industrial sales	26.0	23.7	2.3	9.7 %
Other retail sales, including unbilled revenue	12.4	6.8	5.6	82.4 %
Total retail sales	363.3	315.3	48.0	15.2 %
Transportation sales	3.4	1.6	1.8	112.5 %
Sales to other utilities and marketers	24.3	40.6	(16.3)	(40.1)%
Other	8.2	17.5	(9.3)	(53.1)%
Total electric operating revenues	$ 399.2	$ 375.0	$ 24.2	6.5 %

Electric retail sales increased $48.0 million for the three months ended September 30, 2006 compared to the same period in 2005 due primarily to rate increases related to the PCORC rate increases of November 7, 2005 and July 1, 2006 and increased retail sales volumes. The PCORC rate increases provided $32.8 million to electric operating revenues for the three months ended September 30, 2006 compared to the same period in 2005. Retail electricity usage increased 152,648 MWh or 3.4% for the three months ended September 30, 2006 compared to the same period in 2005, which resulted in an approximate $10.7 million increase in electric operating revenue. During the three month period ended September 30, 2006, the benefits of the Residential and Farm Energy Exchange Benefit credited to customers reduced electric operating revenues by $37.6 million compared to $36.2 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 September 30, 2006, the benefits of PTCs were passed through to electric customers by crediting customers' bills, which reduced electric operating revenues by $3.1 million. The PTCs that reduce income taxes are based on generation from the wind plants. The PTCs began November 2005 when the Hopkins Ridge wind generation facility was placed in service.

Transportation sales increased $1.8 million for the three months ended September 30, 2006 compared to the same period in 2005 due to an increase in sales volume of 34,626 MWh or 6.7%.

Sales to other utilities and marketers decreased $16.3 million for the three months ended September 30, 2006 compared to the same period in 2005. Increased retail customer usage was served by PSE's generation portfolio resulting in less generation available for resale in the wholesale market. The decrease in sales to other utilities and marketers was also related to slightly lower wholesale market prices as compared to the same period in 2005.

Other electric revenues decreased $9.3 million for the three months ended September 30, 2006 compared to the same period in 2005, primarily due to gains that occurred in 2005 from gas financial hedges on gas sold and gains from physical sales of gas that had been purchased for the Tenaska, Frederickson and Encogen plants that did not recur. Lower prices for gas in 2006 resulted in an increased usage of the combustion turbines and reduced sales of gas in the wholesale market.

The table below sets forth changes in electric operating revenues for PSE for the nine months ended September 30, 2006 compared to the same period in 2005.

(DOLLARS IN MILLIONS) NINE MONTHS ENDED SEPTEMBER 30,	2006	2005	CHANGE	PERCENT CHANGE
Electric operating revenues:				
Residential sales	$ 559.3	$ 496.5	$ 62.8	12.6 %
Commercial sales	516.9	461.1	55.8	12.1 %
Industrial sales	76.4	68.9	7.5	10.9 %
Other retail sales, including unbilled revenue	(8.9)	(7.6)	(1.3)	17.1 %
Total retail sales	1,143.7	1,018.9	124.8	12.2 %
Transportation sales	8.8	6.7	2.1	31.3 %
Sales to other utilities and marketers	56.9	73.8	(16.9)	(22.9)%
Other	38.3	41.1	(2.8)	(6.8)%
Total electric operating revenues	$ 1,247.7	$ 1,140.5	$ 107.2	9.4 %

Electric retail sales increased $124.8 million for the nine months ended September 30, 2006 compared to the same period in 2005 due primarily to increased retail sales volumes, rate increases related to the PCORC rate increases of November 1, 2005 and July 1, 2006 and an increase in electric general tariff rates of March 4, 2005. The PCORC and electric general rate increases provided an additional $50.7 million to electric operating revenues for the nine months ended September 30, 2006 compared to the same period in 2005. Retail electricity usage increased 554,821 MWh or 3.8% for the nine months ended September 30, 2006 compared to the same period in 2005. The increase in electricity usage was mainly the result of a 1.5% higher average number of customers served in the nine month period ended September 30, 2006 compared to the same period in 2005.

During the nine month period ended September 30, 2006, the benefits of the Residential and Farm Energy Exchange Benefit credited to customers reduced electric operating revenues by $137.4 million compared to $132.6 million for the same period in 2005. This credit also reduced power costs by a corresponding amount with no impact on earnings as this payment is passed through to customers through a lower residential exchange tariff credit.

During the nine month period ended September 30, 2006, transportation sales increased by $2.1 million due to an increase in sales volumes of 87,106 MWh or 5.7% as compared to the same period in 2005.

Sales to other utilities and marketers decreased $16.9 million compared to the nine month period ended September 30, 2005. Increased retail customer usage was served by PSE's generation portfolio resulting in less generation available for resale in the wholesale market. The decrease was also related to lower wholesale market prices in 2006 as compared to the nine month period ended September 30, 2005.

Other electric revenues decreased $2.8 million for the nine month period ended September 30, 2006 compared to the same period in 2005, primarily from reduction in sale of excess non-core gas. 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
Power Cost Only Rate Case	July 1, 2006	5.9 %	45.3 [1]

[1] *The rate increase is for the period July 1, 2006 through December 31, 2006. The annualized basis of the PCORC rate increase is $96.1 million.*

GAS OPERATING REVENUES

The table below sets forth changes in gas operating revenues for PSE for the three months ended September 30, 2006 compared to the same period in 2005.

(DOLLARS IN MILLIONS) THREE MONTHS ENDED SEPTEMBER 30,	2006	2005	CHANGE	PERCENT CHANGE
Gas operating revenues:				
Residential sales	$ 60.9	$ 57.3	$ 3.6	6.3 %
Commercial sales	41.8	37.2	4.6	12.4 %
Industrial sales	10.0	9.2	0.8	8.7 %
Total retail sales	112.7	103.7	9.0	8.7 %
Transportation sales	3.1	3.3	(0.2)	(6.1)%
Other	3.8	4.0	(0.2)	(5.0)%
Total gas operating revenues	$ 119.6	$ 111.0	$ 8.6	7.7 %

Gas retail sales increased $9.0 million for the three months ended September 30, 2006 compared to the same period in 2005 due to higher PGA mechanism rates in 2006 slightly offset by decreased 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 September 30, 2006, the effects of the PGA mechanism rate increases provided an increase of $12.2 million in gas operating revenues. Increases in temperatures for the three months ended September 30, 2006 compared to the same period in 2005 resulted in a decrease in heating degree days and a corresponding decrease in customer usage by 1.6 million therms or approximately $1.2 million in gas operating revenues.

The table below sets forth changes in gas operating revenues for PSE for the nine months ended September 30, 2006 compared to the same period in 2005.

(DOLLARS IN MILLIONS) NINE MONTHS ENDED SEPTEMBER 30,	2006	2005	CHANGE	PERCENT CHANGE
Gas operating revenues:				
Residential sales	$ 436.0	$ 360.7	$ 75.3	20.9 %
Commercial sales	221.0	178.9	42.1	23.5 %
Industrial sales	39.4	32.2	7.2	22.4 %
Total retail sales	696.4	571.8	124.6	21.8 %
Transportation sales	9.8	9.9	(0.1)	(1.0)%
Other	12.4	13.0	(0.6)	(4.6)%
Total gas operating revenues	$ 718.6	$ 594.7	$ 123.9	20.8 %

Gas retail sales increased $124.6 million for the nine months ended September 30, 2006 compared to the same period in 2005 due to higher PGA mechanism rates in 2006, approval of a 3.5% general gas rate increase in the gas general rate case and higher retail customer gas usage. The Washington Commission approved a PGA mechanism rate increase effective October 1, 2005 that provided $81.3 million in gas revenues for the nine months ended September 30, 2006 compared to the same period in 2005. In addition, the gas general rate case increase provided an additional $7.0 million in gas operating revenues for the nine months ended September 30, 2006 compared to the same period in 2005. The remaining increase in gas retail revenues was primarily due to an increase in customers which increased 3.0% and higher gas sales of 38.8 million therms or $32.8 million for the nine months ended September 30, 2006 compared to the same period in 2005.

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
Purchased Gas Adjustment	September 27, 2006	10.2 %	95.1

Operating Expenses

The table below sets forth significant changes in operating expenses for PSE and its subsidiaries for the three months ended September 30, 2006 compared to the same period in 2005.

(Dollars in Millions) Three Months Ended September 30,	2006	2005	Change	Percent Change
Purchased electricity	$ 183.7	$ 200.9	$ (17.2)	(8.6)%
Electric generation fuel	36.3	21.1	15.2	72.0 %
Residential exchange credit	(35.9)	(34.5)	(1.4)	(4.1)%
Purchased gas	68.3	59.1	9.2	15.6 %
Unrealized (gain) loss on derivative instruments	(0.6)	0.5	(1.1)	*
Utility operations and maintenance	87.7	81.7	6.0	7.3 %
Depreciation and amortization	65.5	60.5	5.0	8.3 %
Conservation amortization	7.1	5.6	1.5	26.8 %
Taxes other than income taxes	46.3	44.8	1.5	3.3 %
Income taxes	8.5	2.6	5.9	*

* *Percent change not applicable or meaningful*

The table below sets forth significant changes in operating expenses for PSE and its subsidiaries for the nine months ended September 30, 2006 compared to the same period in 2005.

(Dollars in Millions) Nine Months Ended September 30,	2006	2005	Change	Percent Change
Purchased electricity	$ 623.8	$ 588.0	$ 35.8	6.1 %
Electric generation fuel	72.2	54.4	17.8	32.7 %
Residential exchange credit	(131.2)	(126.7)	(4.5)	(3.6)%
Purchased gas	453.3	359.0	94.3	26.3 %
Utility operations and maintenance	258.7	240.3	18.4	7.7 %
Depreciation and amortization	194.0	178.3	15.7	8.8 %
Conservation amortization	22.6	16.8	5.8	34.5 %
Taxes other than income taxes	180.2	165.0	15.2	9.2 %
Income taxes	64.7	55.4	9.3	16.8 %

Purchased electricity expenses decreased $17.2 million and increased $35.8 million for the three and nine months ended September 30, 2006, respectively, compared to the same periods in 2005. The decrease for the three months ended September 30, 2006 was primarily the result of lower wholesale market prices and reduced purchase volumes related to increased electric generation. Total purchased power for the three months ended September 30, 2006 decreased 217,863 MWh or 5.8% compared to the same period in 2005. The increase for the nine months ended September 30, 2006 was primarily the result of the overrecovery of power costs and higher customer MWh sales. Total purchased power for the nine months ended September 30, 2006 increased 620,671 MWh or 5.1% compared to the same period in 2005. Increases in the purchases offset by slightly lower wholesale prices of power contributed $6.4 million to the increase for the nine months ended September 30, 2006. The increase also reflected the reversal of previously deferred excess power costs of $16.6 million due to lower power costs than what is in the baseline PCA mechanism rate. 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 that did not reoccur in 2006. 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 $5.1 million due in part to increased kWh sales to customers.

PSE's hydroelectric production and related power costs in 2005 were 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 lower runoff may have on the amount of electricity that will need to be purchased. The July 10, 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 September 2006 would be 106% of normal, which compares to 86% of normal observed runoff for the same period in 2005. The 2007 Columbia Basin Runoff Forecast will be available in December 2006.

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 $15.2 million and $17.8 million for the three and nine months ended September 30, 2006, respectively, compared to the same periods in 2005. The increase for the three months ended September 30, 2006 was primarily the result of an increase of $12.9 million in the cost of fuel due to higher volumes of electricity generated at PSE-controlled combustion turbine generating facilities and an increase in the cost of coal at Colstrip generating facilities of $2.3 million compared to the same period in 2005. The increase for the nine months ended September 30, 2006 was primarily the result of an increase of $13.2 million in the cost of fuel at PSE-controlled combustion turbine generating facilities due to higher volumes of electricity generated and an increase in the cost of coal at Colstrip generating facilities of $4.5 million compared to the same period in 2005.

Residential exchange credits associated with the Residential Purchase and Sale Agreement with BPA increased $1.4 million and $4.5 million for the three and nine months ended September 30, 2006, respectively, compared to the same periods in 2005, as a result of increased residential and small farm customer electric load. The residential exchange credit is a pass-through tariff item with a corresponding credit in electric operating revenue; thus, it has no impact on electric margin or net income. Effective October 1, 2006, the annual payment PSE receives from Bonneville Power Administration will decrease to $105.5 million for the period through September 30, 2007. This will have no impact on PSE's earnings as this payment is passed through to customers through a lower residential exchange tariff credit.

Purchased gas expenses increased $9.2 million and $94.3 million for the three and nine months ended September 30, 2006, respectively, compared to the same periods 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 September 30, 2006 and December 31, 2005 was $83.7 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.

On June 30, 2006 Northwest Pipeline (NWP) filed a Section 4 rate case with the FERC. New rates for NWP will become effective, subject to refund, on January 1, 2007. This is the first increase in rates from NWP since 1997 and the increase (approximately 42%) reflects costs related to a substantial reconstruction of the pipeline system in Western Washington. The proposed new rates, if approved, will increase PSE's gas costs by approximately $26.0 million annually. PSE expects settlement discussions with the pipeline to commence in the fourth quarter 2006. PSE anticipates a settlement can be achieved by first quarter 2007. The new higher rates for service from NWP are already reflected in PSE's PGA rates that became effective October 1, 2006. Any reduction in the proposed rates, as a result of settlement, will be flowed back to PSE's customers through the PGA.

On June 30, 2006 Gas Transmission Northwest (GTN) filed a Section 4 rate case with the FERC. New rates for GTN will become effective, subject to refund, on January 1, 2007. This is the first increase in rates from GTN since 1995 and the increase (approximately 70%) primarily results from spreading annual cost over fewer contracted volumes. The proposed new rates, if approved, will increase PSE's gas costs by approximately $2.0 million annually. PSE expects settlement discussions with the pipeline to commence in the fourth quarter 2006. PSE anticipates a settlement by second quarter 2007. The new higher rates for service from GTN are already reflected in PSE's PGA rates that became effective October 1, 2006. Any reduction in the proposed rates, as a result of settlement, will be flowed back to PSE's customers through the PGA.

Unrealized gain on derivative instruments increased $1.1 million for the three months ended September 30, 2006, compared to the same period in 2005 primarily as a result of the reversal of prior quarter unrealized gains and losses on contracts that did not qualify for normal purchase normal sale exception to derivative accounting rules and de-designated gas hedges for electric generation that were no longer probable.

Utility operations and maintenance expense increased $6.0 million and $18.4 million for the three and nine months ended September 30, 2006, compared to the same period in 2005. The increase for the three months ended September 30, 2006 was due to an increase of $3.5 million in production costs at Colstrip as a result of a major overhaul at Unit 1 and as a result of PSE's Hopkins Ridge wind project that became operational on November 26, 2005. In addition, electric transmission and distribution costs increased by $3.0 million compared to three months ended September 30, 2005 primarily due to planned infrastructure maintenance work. The increase for the nine months ended September 30, 2006 was primarily due to higher electric distribution system restoration costs as a result of a series of strong winter storms with high winds in Western Washington during the first quarter 2006. Storm damage related costs increased $7.2 million compared to the same period in 2005. In addition, maintenance of electric and gas distribution system increased $3.8 million, customer service and call center costs increased $2.9 million and gas operations and distribution costs increased $2.8 million for the nine months ended September 30, 2006 compared to the same period in 2005. In addition, production costs increased by $3.4 million primarily related to Colstrip and the Hopkins Ridge wind project. These increases were slightly offset by a decrease of $1.7 million in other expenses. 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 $5.0 million and $15.7 million for the three and nine months ended September 30, 2006, respectively, compared to the same periods in 2005 due to additional utility plant placed in service. Included in the increase for the three and nine months ended September 30, 2006 is a $2.3 million and $6.6 million increase, respectively, 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 is completed.

Conservation amortization increased $1.5 million and $5.8 million for the three and nine months ended September 30, 2006, respectively, compared to the same periods 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 $1.5 million and $15.2 million for the three and nine months ended September 30, 2006, respectively, compared to the same periods 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. For the nine months ended September 30, 2006, the increase was slightly offset by a 2006 property tax reduction that was settled with the Washington State Department of Revenue in August 2006 resulting in a lower valuation than in 2005.

Income taxes increased $5.9 million and $9.3 million for the three and nine months ended September 30, 2006, respectively, compared to the same periods in 2005. The increase for the three months ended September 30, 2006 was the result of higher taxable income and a higher effective tax rate related to the true-up of the prior year federal income tax provision which resulted in an expense in 2006 versus a benefit in 2005. The increase for the nine months ended September 30, 2006 as compared to the same period in 2005 was due to higher taxable income offset by a lower effective tax rate influenced by PTCs of $4.9 million.

OTHER INCOME AND INTEREST CHARGES

The table below sets forth significant changes in other income for PSE and its subsidiaries for the three months ended September 30, 2006 compared to the same period in 2005.

(DOLLARS IN MILLIONS) THREE MONTHS ENDED SEPTEMBER 30,	2006	2005	CHANGE	PERCENT CHANGE
Other income (net of tax)	$ 4.4	$ 1.4	$ 3.0	*

* *Percent change not applicable or meaningful*

Other income increased $3.0 million for the three months ended September 30, 2006 compared to the same period in 2005 primarily due to an increase of $2.6 million related to the return of regulatory assets and a decrease of $1.2 million in long-term incentive plan expense. These increases were offset by an increase of $0.8 million in various other expenses.

The table below sets forth significant changes in other income for PSE and its subsidiaries for the nine months ended September 30, 2006 compared to the same period in 2005.

(DOLLARS IN MILLIONS) NINE MONTHS ENDED SEPTEMBER 30,	2006	2005	CHANGE	PERCENT CHANGE
Other income (net of tax)	$ 11.8	$ 4.2	$ 7.6	*

* *Percent change not applicable or meaningful*

Other income increased $7.6 million for the nine months ended September 30, 2006 compared to the same period in 2005 primarily due to an increase of $5.3 million related to the return on regulatory assets, a decrease of $3.1 million in long-term incentive plan expenses and an increase of $1.5 million related to the equity portion of allowance for funds used during construction (AFUDC). These increases were offset by a decrease of $2.3 million in various other income items.

INFRASTRUX

On May 7, 2006, Puget Energy sold InfrastruX to an affiliate of Tenaska Power Fund, L.P. (Tenaska). After repayment of debt, adjustments for working capital, transaction costs and distributions to minority interests, Puget Energy received after-tax cash proceeds of approximately $95.9 million for its 90.9% interest in InfrastruX in the second quarter 2006. The sale resulted in an after-tax gain of $29.8 million for the nine months ended September 30, 2006. The repayment of InfrastruX's debt by Puget Energy released Puget Energy's corporate guarantee relating to the debt. Puget Energy accounted for InfrastruX as a discontinued operation under SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" in 2005 and 2006.

Under the terms of the sale agreement, Puget Energy is obligated for certain representations and warranties made by InfrastruX concerning its business. Puget Energy obtained a representation and warranty insurance policy and deposited $3.7 million into an escrow account to serve as retention under the policy. As of September 30, 2006, long-term restricted cash in the amount of $3.7 million is included in the accompanying balance sheets; that amount represents management's estimate of the aggregate fair value of the amount potentially payable under those representations and warranties and is Puget Energy's maximum exposure. The obligation expires May 7, 2008. Should Tenaska make any claims against Puget Energy, payment for the claims will be made from the escrow account, and total payments are limited to $3.7 million plus any interest earned while the funds are in the escrow account. Puget Energy also agreed to indemnify the purchaser for certain potential future losses related to one of InfrastruX's subsidiary companies. Under the indemnity agreement, Puget Energy is liable for certain costs with the maximum amount of loss not to exceed $15.0 million. As of September 30, 2006, a liability in the amount of $5 million is included in the accompanying balance sheets; that amount represents Puget Energy's estimate of the fair value of the amount potentially payable using a probability-weighted approach to a range of future cash flows. The obligation expires May 7, 2011. Puget Energy also provided an environmental guaranty as part of the sale agreement. Under the terms of the agreement, Tenaska will be responsible for the first $0.1 million of environmental claims, Tenaska and Puget Energy will share the next $6.4 million equally and Puget Energy will be responsible for the next $3.5 million. Puget Energy believes it will not have a future loss in connection with the environmental guarantee.

For the nine months ended September 30, 2006, Puget Energy reported InfrastruX related income from discontinued operations (net of taxes and minority interest), including gain on sale, of $51.9 million compared to $0.9 million (net of taxes and minority interest) for the nine months ended September 30, 2005, respectively. Puget Energy’s income from discontinued operations for the nine months ended September 30, 2006 includes $7.3 million related to the reversal of a carrying value adjustment recorded in 2005 as well as $10.0 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.”

InfrastruX's operating revenue for the nine months ended September 30, 2006 was $138.6 million compared to $286.7 million for the same period in 2005. Pre-tax income for the nine months ended September 30, 2006 was $9.9 million for the same period in 2005.

CAPITAL REQUIREMENTS

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

Puget Energy. The following are Puget Energy's aggregate consolidated (including PSE) contractual obligations and commercial commitments as of September 30, 2006:

PUGET ENERGY					
		PAYMENTS DUE PER PERIOD			
CONTRACTUAL OBLIGATIONS (DOLLARS IN MILLIONS)	Total	2006	2007-2008	2009-2010	2011 & Thereafter
Long-term debt including interest	$ 5,524.6	$ 80.2	$ 638.8	$ 678.0	$ 4,127.6
Short-term debt including interest	103.2	103.2	--	--	--
Junior subordinated debentures payable to a subsidiary trust including interest[1]	102.0	0.8	6.2	6.2	88.8
Mandatorily redeemable preferred stock	1.9	--	--	--	1.9
Service contract obligations	166.5	7.3	67.2	60.8	31.2
Non-cancelable operating leases	91.7	3.2	29.1	21.8	37.6
Fredonia combustion turbines lease [2]	57.1	1.0	8.2	8.2	39.7
Energy purchase obligations	6,329.5	290.3	1,812.0	1,284.2	2,943.0
Contract initiation payment/collateral requirement	18.5	--	--	--	18.5
Financial hedge obligations	8.4	(4.7)	13.1	--	--
Purchase obligations	67.7	35.3	9.7	22.7	--
Non-qualified pension and other benefits funding	49.7	2.4	11.1	10.2	26.0
Total contractual cash obligations	$ 12,520.8	$ 519.0	$ 2,595.4	$ 2,092.1	$ 7,314.3

PUGET ENERGY					
		AMOUNT OF COMMITMENT EXPIRATION PER PERIOD			
COMMERCIAL COMMITMENTS (DOLLARS IN MILLIONS)	TOTAL	2006	2007-2008	2009-2010	2011 & THEREAFTER
Indemnity agreements [3]	$ 8.7	$ --	$ 3.7	$ --	$ 5.0
Credit agreement - available [4]	396.3	--	--	--	396.3
Unsecured credit agreement	20.0	--	--	--	20.0
Receivable securitization facility [5]	171.7	--	--	171.7	--
Energy operations letter of credit	0.5	0.5	--	--	--
Total commercial commitments	$ 597.2	$ 0.5	$ 3.7	$ 171.7	$ 421.3

1 *In 1997, PSE formed Puget Sound Energy Capital Trust I 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 Trust 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 *Under the InfrastruX sale agreement, Puget Energy is obligated for certain representations and warranties concerning InfrastruX's business and anti-trust inquiries. The fair value of the business warranty is $3.7 million at September 30, 2006 and the obligation expires on May 7, 2008. Puget Energy also agreed to indemnify the buyer relating to an anti-trust inquiry of an InfrastruX subsidiary that had a fair value of $5.0 million at September 30, 2006. See "InfrastruX" above for further discussion.*

4 *At September 30, 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 September 30, 2006, PSE had $0.5 million for an outstanding letter of credit and $103.2 million commercial paper outstanding, effectively reducing the available borrowing capacity to $396.3 million.*

5 *At September 30, 2006, PSE had available a $171.7 million receivables securitization facility that expires in December 2010. There were no amounts outstanding under the receivables securitization facility at September 30, 2006. The facility allows receivables to be used 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. The borrowing base of eligible receivables at September 30, 2006 was $171.7 million. See "Receivables Securitization Facility" below for further discussion.*

Puget Sound Energy. The following are PSE's aggregate contractual obligations and commercial commitments as of September 30, 2006:

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	$ 5,524.6	$ 80.2	$ 638.8	$ 678.0	$ 4,127.6
Short-term debt including interest[1]	127.5	127.5	--	--	--
Junior subordinated debentures payable to a subsidiary trust including interest[2]	102.0	0.8	6.2	6.2	88.8
Mandatorily redeemable preferred stock	1.9	--	--	--	1.9
Service contract obligations	166.5	7.3	67.2	60.8	31.2
Non-cancelable operating leases	91.7	3.2	29.1	21.8	37.6
Fredonia combustion turbines lease [3]	57.1	1.0	8.2	8.2	39.7
Energy purchase obligations	6,329.5	290.3	1,812.0	1,284.2	2,943.0
Contract initiation payment/collateral requirement	18.5	--	--	--	18.5
Financial hedge obligations	8.4	(4.7)	13.1	--	--
Purchase obligations	67.7	35.3	9.7	22.7	--
Non-qualified pension and other benefits funding	49.7	2.4	11.1	10.2	26.0
Total contractual cash obligations	$ 12,545.1	$ 543.3	$ 2,595.4	$ 2,092.1	$ 7,314.3

PUGET SOUND ENERGY COMMERCIAL COMMITMENTS (DOLLARS IN MILLIONS)	TOTAL	AMOUNT OF COMMITMENT EXPIRATION PER PERIOD 2006	2007-2008	2009-2010	2011 & THEREAFTER
Credit agreement - available [4]	$ 396.3	$ --	$ --	$ --	$ 396.3
Unsecured credit agreement	20.0	--	--	--	20.0
Receivable securitization facility [5]	171.7	--	--	171.7	--
Energy operations letter of credit	0.5	0.5	--	--	--
Total commercial commitments	$ 588.5	$ 0.5	$ --	$ 171.7	$ 416.3

1 *Short-term borrowing includes $24.3 million outstanding debt and interest under a Demand Promissory Note owed to Puget Energy. The outstanding balance under the Demand Promissory Note is eliminated by Puget Energy upon consolidation of PSE's financial statements.*

2 *See note 1 under Puget Energy above.*

3 *See note 2 under Puget Energy above.*

4 *See note 4 under Puget Energy above.*

5 *See note 5 under Puget Energy 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 lease 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 September 30, 2006, PSE's outstanding balance under the lease was $51.8 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 $575.1 million for the nine months ended September 30, 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	$ 444	$ 500
Wild Horse wind project	317	--
Total capital expenditures	761	500
Chelan contract payment[1]	89	--
Total expenditures	$ 850	$ 500

1 *The Chelan contract payment represents a capacity reservation charge in conjunction with a 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 nine months ended September 30, 2006 was $152.5 million. During that period the debt portion of AFUDC, which reduced interest expense, was $10.2 million and $78.1 million was used for payment of dividends. Consequently, cash flows available for utility construction expenditures and other capital expenditures were $64.2 million or 11.1% of the $579.0 million in construction expenditures (net of the equity portion of AFUDC and customer refundable contributions) and other capital expenditure requirements for the nine months ended September 30, 2006. For the nine months ended September 30, 2005, cash generated from operations was $301.0 million, the debt portion of AFUDC, which reduced interest expense, was $6.2 million, and $65.9 million was used for payment of dividends. Therefore, cash flows available for utility construction expenditures and other capital expenditures were $228.9 million, or 57.1% of the $400.7 million in construction expenditures (net of the equity portion of AFUDC and customer refundable contributions) and other capital expenditure requirements for the nine months ended September 30, 2005.

The following table provides a summary of cash available and construction expenditures:

(DOLLARS IN MILLIONS) (UNAUDITED) NINE MONTHS ENDED SEPTEMBER 30,	2006	2005
Cash from operations	$ 152.5	$ 301.0
Less: Dividends paid	(78.1)	(65.9)
AFUDC	(10.2)	(6.2)
Cash available for construction expenditures	$ 64.2	$ 228.9
Construction and energy efficiency expenditures	$ 601.2	$ 417.1
Less: AFUDC	(10.2)	(6.2)
Cash received from refundable customer contributions	(12.0)	(10.2)
Net construction and energy efficiency expenditures	$ 579.0	$ 400.7

The overall cash generated from operating activities for the nine month period ended September 30, 2006 decreased $148.5 million compared to the same period in 2005. This decrease in cash from operations is primarily attributable to a non-refundable capacity reservation prepayment of $89.0 million in April 2006 for the Chelan PUD power sales agreement. This agreement will begin providing power to PSE at the end of 2011. In addition, cash from operations decreased $24.8 million due to an increase in the amount of taxes paid in 2006 as compared to 2005. Cash from operations was also negatively impacted by a $22.0 million refund of collateral deposits related to energy counterparties compared to a $31.0 million receipt in 2005; a $15.0 million payment to fund Puget Sound Energy charitable foundation; and an increase of $110.0 million in payments made for accounts payable related to energy purchases. Offsetting the decrease in cash from operations is an increase in accounts receivable of $128.2 million. The increase in accounts receivable is primarily attributable to Rainier Receivables accounts receivable securitization sale of $150 million in December 2004 that was collected from customers and directly provided to Rainier Receivables in the first quarter 2005. This compares to no activity under the Rainier Receivables accounts receivable securitization at December 31, 2005 due to termination of the Rainier Receivables accounts receivable securitization program in December 2005. As a result, cash from operations increased due to collection of accounts receivable in 2006. Collections of accounts receivable will increase in the second and third quarters of the year due to the higher accounts receivable balances in the first and fourth quarters of the year resulting from the seasonality of PSE's business.

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 September 30, 2006, PSE could issue:

- approximately $245 million of additional first mortgage bonds under PSE's electric mortgage indenture based on approximately $408 million of electric bondable property available for issuance, subject to an interest coverage ratio limitation of 2.0 times net earnings available for interest (as defined in the electric utility mortgage), which PSE exceeded at September 30, 2006;
- approximately $361 million of additional first mortgage bonds under PSE's gas mortgage indenture based on approximately $602 million of gas bondable property available for issuance, subject to interest coverage ratio limitations of 1.75 times and 2.0 times net earnings available for interest (as defined in the gas utility mortgage), which PSE exceeded at September 30, 2006;
- approximately $660 million of additional preferred stock at an assumed dividend rate of 7.0%; and
- approximately $689 million of unsecured long-term debt.

At September 30, 2006, PSE had approximately $3.9 billion in electric and gas ratebase to support the interest coverage ratio limitation test for net earnings available for interest. SFAS No. 158 will not have an impact on PSE's ratebase.

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 October 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.

On September 18, 2006, PSE completed the issuance of $300 million of senior secured notes at a rate of 6.274%, which are due on March 15, 2037. The net proceeds from the issuance of the senior notes of approximately $297.4 million will be used to repay PSE's outstanding short-term debt which was incurred primarily to fund construction programs. The yield to maturity of the $300 million senior secured notes was 6.29% after the settlement of two forward starting swap interest rate contracts.

On June 30, 2006, PSE redeemed for $200 million all of the outstanding shares of 8.40% Trust Originated Preferred Securities of The Puget Sound Energy Capital Trust II (classified as Junior Subordinated Debentures of the Corporation Payable to a Subsidiary Trust Holding Mandatorily Redeemable Preferred Securities on the balance sheet) at $25 par value per share plus accrued interest to the redemption date.

On June 30, 2006, PSE completed the issuance of $250 million of senior secured note at a rate of 6.724% which are due on June 15, 2036. The net proceeds from the issuance of the senior notes of approximately $247.8 million were used to redeem $200 million of 8.40% Trust Originated Preferred Securities of the Puget Sound Energy Capital Trust II, which were redeemed at par on June 30, 2006, and to repay a portion of PSE's short-term debt. The short-term debt was incurred to repay $46 million of 8.06% senior notes that matured June 19, 2006. The yield to maturity of the $250 million senior secured notes was 6.17% after the settlement of two interest rate forward starting swap contracts.

FORWARD STARTING INTEREST RATE SWAP SETTLEMENT

In the third quarter 2006, the Company entered into two forward starting swap instruments that were designated by PSE as cash flow hedges at the inception of the contracts. The purpose of the forward starting swap contracts was to hedge interest rate volatility for a debt offering of $300 million that was priced on September 13, 2006. The settlement loss of $0.6 million ($0.4 million after-tax) was recorded in other comprehensive income. In accordance with SFAS No. 133, this loss will be amortized out of other comprehensive income as an increase to interest expense over 30 years.

In the second quarter 2006, the Company settled its two forward starting interest rate swap contracts originating in May 2005. The purpose of the forward starting swap contracts was to hedge interest rate volatility for a debt offering of $200 million that was completed on June 30, 2006. Since interest rates increased relative to the hedged rate, PSE received $21.3 million from the counterparties when the contracts were settled. The forward starting swap contracts were designated and documented under SFAS No. 133 criteria as cash flow hedges, with all changes in market value for each reporting period presented net of tax in other comprehensive income. In the second quarter 2006, the settlement gain on these instruments amounted to $13.9 million after-tax and was recorded as a gain in other comprehensive income. In accordance with SFAS No. 133, the gain will be amortized out of other comprehensive income to current earnings as a decrease to interest expense over the life of the new debt issued at an annual rate of approximately $0.7 million before tax.

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 September 30, 2006.

Demand Promissory Note. On June 1, 2006, PSE entered into a revolving credit facility with its parent, Puget Energy, in the form of a Demand Promissory Note (Note). Through the Note, PSE may borrow up to $30 million from Puget Energy, subject to approval by Puget Energy. Under the terms of the Note, PSE pays interest on the outstanding borrowings based on the lowest of the weighted average interest rate of (a) PSE's outstanding commercial paper interest rate; (b) PSE's senior unsecured revolving credit facility; or (c) the interest rate available under the receivable securitization facility of PSE Funding, Inc., a PSE subsidiary, which is the LIBOR rate plus a marginal rate. At September 30, 2006, the outstanding balance of the Note was $24.2 million. The outstanding balance and the related interest under the Note are eliminated by Puget Energy upon consolidation of PSE's financial statements.

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 September 30, 2006, there was $0.5 million outstanding under a letter of credit and $103.2 million commercial paper outstanding, effectively reducing the available borrowing capacity under the credit facility to $396.3 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 nine months ended September 30, 2006, PSE Funding borrowed a cumulative amount of $288 million secured by accounts receivable. There were no loans secured by accounts receivable pledged as collateral at September 30, 2006. The borrowing base of eligible receivables at September 30, 2006 was $171.7 million.

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 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 common stock under the Stock Purchase and Dividend Reinvestment Plan of $3.3 million (150,295 shares) and $10.2 million (481,930 shares) for the three and nine months ended September 30, 2006, respectively, compared to $3.6 million (159,985shares) and $10.9 million (480,005 shares) for the three and nine months ended September 30, 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, 2007, 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. On April 7, 2006, FERC issued a Draft Environmental Impact Statement discussing the proposed settlement. A Final Environmental Impact Statement was issued on September 8, 2006. However, FERC has not yet ruled on the proposed settlement and its ultimate outcome remains uncertain.

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 the project economically 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 September 30, 2006, the White River project net book value totaled $68.5 million, which included $43.8 million of net utility plant, $16.9 million of capitalized FERC licensing costs, $5.3 million of costs related to construction work in progress and $1.7 million related to dam operations and safety On February 18, 2005, the Washington Commission approved the recovery of the White River net utility plant costs but did not allow current recovery of FERC licensing costs and other related costs until all costs associated with selling the White River plant 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. Ecology issued a revised decision on September 25, 2006 in draft form for public comment. 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.

Snoqualmie Falls project. The Snoqualmie Falls project, built in 1898, had its original license issued May 13, 1975, which was made effective retroactive to March 1, 1956, and expired on December 31, 1993. PSE filed its application to relicense the project on November 25, 1991, and operated the project pursuant to annual licenses issued by FERC after the original license expired. On June 29, 2004, FERC granted PSE a new 40-year operating license for the Snoqualmie Falls project. PSE estimates that the investment required to implement the conditions of the new license agreement will cost approximately $44.0 million. These conditions include modified operating procedures and various project upgrades that include better protection of fish, development of riparian habitat to promote fish propagation, increased minimum flows in the Snoqualmie River during low-water periods and the development of recreational amenities near the down-river power house. On July 29, 2004, the Snoqualmie Tribe and certain other parties filed a request for rehearing of the new license and a request to stay the FERC license. On March 1, 2005, FERC issued an Order on Rehearing and Dismissing Stay Request. The order requires additional flows at Snoqualmie Falls during certain times of the year. PSE requested rehearing of the order on the grounds that the order interferes with the Washington State Department of Ecology's authority to regulate water quality and that FERC arbitrarily and capriciously rebalanced the public interest without support of substantive evidence in the record. The Snoqualmie Tribe appealed FERC's operating license decision to the United States Court of Appeals for the Ninth Circuit and PSE intervened in that proceeding. PSE's request for rehearing was denied on June 1, 2005 and on July 8, 2005, PSE asked for further review by the Ninth Circuit. The two petitions have been consolidated and briefing is anticipated to be completed by the fourth quarter 2006.

ELECTRIC REGULATION AND RATES

Power Cost Only Rate Case and Electric General Rate Case. On June 28, 2006, the Washington Commission approved a 5.9%, or $45.3 million, Power Cost Only Rate Case (PCORC) increase in electric rates for the period July 1, 2006 through

December 31, 2006. The increase allows PSE to recover higher projected costs of power caused primarily by higher market prices for natural gas used as fuel for electric generators. The rate increase will not appreciatively impact PSE's income. The annualized basis of the PCORC rate increase when applied to the general rate case test year is $96.1 million. Primarily as a result of this order, on July 10, 2006, PSE reduced its pending electric general tariff increase from $140.9 million to $42.9 million, or 2.5%, on an annualized basis. On September 15, 2006, the Company adjusted the requested increase to $33.5 million annually. Additionally, PSE has requested approval of a new tariff in its original general rate case filing to recover increases in electric transmission and distribution depreciation costs incurred between general rate cases of $7.9 million. The resolution of the general rate case is expected by the end of 2006.

Residential Exchange Credit. On September 27, 2006, the Washington Commission approved a revision of PSE's electric rate tariff Schedule 94 "Residential and Farm Exchange Benefit" that became effective October 1, 2006. The Schedule 94 credit rate was reduced from $0.01740 to $0.01028 per kWh, reflecting a reduction in the annual estimated value of the BPA Residential Exchange benefits from $174.4 million to $105.0 million, beginning October 1, 2006. This tariff revision will have the impact of increasing PSE electric customer revenues, but will not impact PSE net income. Under federal law, BPA is required to provide benefits from the low-cost federal power system to residential and small farm customer served by investor-owned utilities in the northwest. All benefits received by an investor-owned utility must be passed on to its residential and small farm customers.

Production Tax Credit. On October 30, 2006, PSE revised its PTC electric tariff to increase the credit to customers from $13.1 million to $28.8 million, effective January 1, 2007. The credit is based on expected wind generation and reflects the true-up of prior years' credits provided to customers versus credits for actual wind generation taken for federal income taxes.

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. During the four-year period ended June 30, 2006, PSE's cumulative maximum pre-tax earnings exposure due to power cost variations was limited to $40 million plus 1% of the excess. 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).

Beginning July 1, 2006, the most significant risks are hydroelectric generation variability and wholesale market prices of natural gas and power. On a July through December 2006 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:

Prior to July 2006 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.*

PSE proposed the following change to the annual PCA sharing bands effective January 1, 2007 in its general rate case filing on February 15, 2006:

Power Cost Variability	Customers' Share	Company's Share
+/- $0 - $25 million	50%	50%
+/- $25 - $120 million	90%	10%
+/- $120 million	95%	5%

Gas Regulation and Rates

Gas General Rate Case. On July 10, 2006, PSE reduced its gas general rate increase request filed with the Washington Commission on February 15, 2006 from $40.4 million to $39.2 million, or 4.2%, on an annual basis. On September 15, 2006, the Company adjusted the requested general rate increase to $38.9 million annually. PSE also has requested approval of a new depreciation tracker in its original gas general rate case filing to recover increases in gas distribution depreciation costs incurred between general rate cases of $10.9 million. In addition, a gas decoupling mechanism, which does not have an impact on the current rate increase, was requested; however, it is designed to stabilize revenue changes due to load variations between regulatory filings. The resolution of the general rate case is expected by the end of 2006.

Purchased Gas Adjustment. On September 27, 2006, the Washington Commission approved a revision of PSE's Purchased Gas Adjustment (PGA) tariff schedule that went into effect on October 1, 2006. The tariff changes will increase gas revenue approximately $95.1 million, or 9.9%, on an annual basis. The rate increase authorized PSE to recover higher projected future gas and gas transportation costs, as well as to collect an accumulated deficit (receivable) balance in its PGA balancing account over a 24-month period (beginning October 1, 2006). The PGA rate change will increase PSE's gas revenue, but will not impact the Company's net income as the increased revenue will be offset by increased purchased gas costs. The PGA Mechanism passes through to customers increases or decreases in gas supply portion of the natural gas service rates based upon changes in gas prices.

Other

Whitehorn Power Generating Facility Lease. PSE leases the Whitehorn power generating facility, a 147 MW net capacity dual-fuel combustion turbine, under a noncancelable operating lease expiring in February 2009. PSE entered into an agreement on October 17, 2006 with the lessor under which PSE agreed to purchase the generation facilities after the lease term expires in February 2009, provided that all conditions precedent are satisfied or waived. In the fourth quarter 2006, the lease will be treated as a capital lease over its remaining lease period.

Union Contract. The contract with the United Association of Plumbers and Pipefitters (UA) which governs the Company's relationship with certain of its employees expired as of October 1, 2006. However, PSE and the UA have been operating under the terms of collective bargaining terms of the contract since the expiration as agreed to by both parties. The employees represented by UA rejected a proposal for a four-year contract offer in early October 2006. PSE and the UA are continuing to negotiate a new contract. PSE anticipates reaching a conclusion on the contract in the fourth quarter 2006.

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 and Quarterly Report on Form 10-Q for the quarter ended June 30, 2006 include a summary and subsequent developments relating to the western power market proceedings described below. The following discussion provides a summary of material developments in these proceedings that occurred during and subsequent to 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.

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 Power Exchange Corporation (California PX) for energy purchases. The CAISO in turn failed to pay various energy suppliers, including PSE, for energy sales made 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.

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 has finished publishing settlement statements reflecting the refund rerun, and has begun the financial adjustment phase, in which the CAISO is making adjustments to its refund rerun settlement data to account for fuel cost allowance offsets, emissions offsets, cost-based recovery offsets and interest on amounts unpaid and refunds. 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. *Also see discussion below under CAISO Receivable.*

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 were consolidated. 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 FPA; (2) the temporal scope of refunds under section 206 of the FPA; and (3) which categories of transactions are subject to refunds.

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. On August 2, 2006, the court decided the remaining issues of the first round, ruling that FERC erred in excluding potential relief for tariff violations for periods that pre-dated October 2, 2000, and ruling that FERC should consider remedies for certain CAISO and California PX transactions outside the 24-hour period previously used to define the scope of the proceedings.

The August 2, 2006 decision may adversely impact PSE's ability to recover the full amount of its CAISO Receivable described below, and the decision may expose PSE to claims or liabilities for transactions outside the previously defined "refund period," but at this time the ultimate financial outcome for PSE is unclear. It is likely that some parties will seek rehearing of the court's decision and/or that settlement talks will ensue. If rehearing is denied, the matters would be remanded to FERC for further proceedings. PSE is studying the court's decision, but is unable to predict either the outcome of the proceedings or the ultimate financial effect on PSE at this time. The Ninth Circuit and FERC are trying to facilitate settlement discussions among the parties but it is unclear whether any such discussions will result in settlement.

CAISO Receivable. At September 30, 2006, PSE had a net receivable totaling $21.2 million in connection with wholesale sales in 2000 to the CAISO and counterparties where payment to PSE was conditioned on the counterparties being paid by the California PX. In August 2005, PSE submitted its audited Fuel Cost Allowance Claim with the CAISO. That claim was challenged by the California Parties. PSE filed a portfolio cost claim, and 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 stated claim. PSE filed a revised Portfolio Claim in the amount of $2.3 million on March 3, 2006. PSE does not agree with all of FERC's rulings and sought rehearing, which is still pending at FERC. PSE's ability to recover all or a portion of these claims is uncertain at the present time.

PSE has estimated a range related to its CAISO receivable to be between $21.2 million (PSE's net receivable balance) and $29.5 million, including interest, on its past due receivables as of September 30, 2006. As a result of the Ninth Circuit decision of August 2, 2006 discussed above, PSE cannot assess the ultimate resolution of its California Receivable. At this time there is no reasonable basis to adjust PSE's net receivable balance of $21.2 million because the procedural outcome of a rehearing or remand to FERC is uncertain and any financial impact cannot be quantified.

COLSTRIP MATTERS

In May 2003, approximately 50 plaintiffs brought an action against the owners of Colstrip. The lawsuit alleged certain domestic water wells may have been contaminated by seepage from a Colstrip Units 1 & 2 effluent holding pond. PSE recorded a $0.7 million reserve in the third quarter 2004 for its 50% ownership of the Colstrip Units 1 & 2 project, based upon a tentative settlement agreement in the third quarter 2004. However, the settlement agreement would not resolve certain other claims by residents within the city limits. Before finalizing the settlement, plaintiffs retained new counsel and the litigation continues and is in the discovery phase. Colstrip has extended city water to certain residents who live near the plant in December 2005. PSE reflected the costs to extend the water supply of $0.4 million against the reserve, reducing it to $0.3 million at December 31, 2005. Colstrip continues to address groundwater contamination from wastewater ponds by conducting certain groundwater investigation and remediation measures for certain residents who live near the plant.

On April 29, 2004, the Minerals Management Service of the United States Department of the Interior (MMS) issued an order to Western Energy Company (WECO) to pay additional royalties concerning coal purchased by PSE for Colstrip Units 3 & 4. The order seeks payment of an additional $1.1 million in royalties for coal mined from federal land between 1997 and June 30, 2000. During that period, PSE's coal price was reduced by a settlement agreement entered into in February 1997 among PSE, WECO and Montana Power Company that resolved disputes that were then pending. The order seeks to impute the price charged to PSE based on the other Colstrip Units 3 & 4 owners' contractual amounts. PSE is supporting WECO's appeal of the order, but is also evaluating the basis of the claim. In addition, the State of Montana issued a demand to WECO based upon an audit in May 2005 for allegedly unpaid royalties, asserting this same theory. The amount claimed in that demand is $0.2 million. PSE accrued a loss reserve in the amount of $1.1 million in connection with this matter in the second quarter 2004, and updated that amount to $1.8 million in the third quarter 2006.

In addition, the MMS issued two orders to WECO in 2002 and 2003 to pay additional royalties concerning coal sold to Colstrip Units 3 & 4 owners. The orders assert that additional royalties are owed as a result of WECO not paying royalties in connection with revenue received by WECO from the Colstrip Units 3 & 4 owners under a coal transportation agreement during the period October 1, 1991 through December 31, 2001. On April 28, 2005, the appeals division of the MMS issued an order that reduced the amount claimed due to the application of statute of limitations. PSE's share of the alleged additional royalties is approximately $1.7 million, which is equivalent to PSE's 25% ownership interest in Colstrip Units 3 & 4. The state of Montana issued a demand to WECO in May 2005 consistent with the MMS position outlined above on these transportation revenues. The state's position, if correct, would result in an additional $0.1 million claim against PSE. The transportation agreement provides for the construction and operation of a conveyor system that runs several miles from the mine to Colstrip Units 3 & 4. WECO has appealed these orders and PSE is monitoring the process. PSE believes that the Colstrip Units 3 & 4 owners have reasonable defenses in this matter based upon its review. However, if the MMS position prevails, this issue could create ongoing expenses as the conveyor system continues to be used. Further, on September 28, 2006, the MMS issued an order to pay additional royalties in the amount of $1.5 million on the basis of an audit of WECO's royalty payments during the three years 2002 to 2004 and that applies the same theory to the transportation revenues. PSE's share of that claim is approximately $0.4 million based upon PSE's ownership of the projects. If litigated, this claim would follow the same process as the two already pending, involving a multiple-layer appellate process before a final decision. It is likely that any result would be substantially identical to the resolution on the two periods already pending.

The US Environmental Protection Agency requires states to produce regulations by November 15, 2006 that will bring their mercury emissions in line with those mandated by the Clean Air Mercury Rule (CAMR). The Montana Board of Environmental Review approved the state's regulation to limit mercury emissions from coal-fired plants on October 16, 2006. The new rule takes a two-tiered approach to reducing mercury emissions, allowing power plants burning lower-quality lignite coal to release more emissions than plants burning cleaner sub-bituminous coal, such as Colstrip. The new rule has a more stringent limit than the federal rule (0.9 lbs/TBtu, instead of the federal 1.4 lbs/TBtu), but includes a cap-and-trade provision as well as alternative emission limits for plants that have tried to meet the new standards but have demonstrated that they cannot. The Colstrip owners are still evaluating the potential impact of the new rule and it is still unknown whether the new rule will be appealed.

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 of $0.1 million, after tax, for the quarter ended March 31, 2006. The cumulative effect adjustment is the result of the inclusion of estimated forfeitures occurring before award vesting dates in the computation of compensation expense for unvested awards. 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 nine months ended September 30, 2006, is $0.1 million and $0.1 million higher, respectively, than if it had continued to account for share-based compensation under SFAS No. 123 due to the inclusion of estimated forfeitures in compensation cost. There is no difference between basic and diluted earnings per share for income from continuing operations for the three and nine months ended September 30, 2006, under SFAS No. 123R as compared to earlier methods.

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.

In July 2006, Financial Accounting Standards Board (FASB) issued Interpretation No. 48 (FIN 48), "Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109", which clarifies the accounting for uncertainty in income taxes recognized in the financial statements in accordance with FASB Statement No. 109, "Accounting for Income Taxes." FIN 48 provides guidance on recognition threshold and measurement attributed to a tax position taken or expected to be taken in a tax return. The tax positions should only be recognized when it is more likely than not, based on technical merits, that the position will be sustained upon examination by the taxing authority. FIN 48 is effective for fiscal years beginning after December 15, 2006, which will be the quarter ended March 31, 2007 for the Company. The Company is currently evaluating the provisions of FIN 48 to determine the potential impact, if any, the adoption will have on the Company's financial statements.

On September 15, 2006, FASB issued SFAS No. 157, "Fair Value Measurements." SFAS No. 157 standardizes the measurement of fair value when it is required under generally accepted accounting principles (GAAP). SFAS No. 157 is effective for fiscal years beginning after November 15, 2007, which will be the year beginning January 1, 2008, for the Company. The adoption of SFAS No. 157 is not expected to have a material impact on the Company's financial statements.

On September 29, 2006, FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans." SFAS No. 158 is effective for fiscal years ending after December 15, 2006, which will be the year ended December 31, 2006, for the Company. SFAS No. 158 will be adopted prospectively, as required by the statement. SFAS No. 158 requires 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 projected benefit obligation. At December 31, 2005, the combined fair value of plan assets and projected benefit obligation for the Company's defined benefit pension and the retiree medical and life plans were $481.0 million and $439.0 million, respectively. At September 30, 2006, the Company estimates that upon adoption of the standard, it will record a pre-tax charge to Accumulated Other Comprehensive Income of approximately $64.0 million, a reduction of approximately $54.0 million to the pension plan prepaid asset and an increase of approximately $10.0 million to benefit plan liabilities. Actual return on plan assets for the fourth quarter 2006 could influence these estimates.

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 provided 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. The Company has proposed in its general rate case proceeding a PCA mechanism that 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 beginning January 1, 2007.

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 Audit 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. 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, and 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 September 30, 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 September 30, 2006, the Company had a net asset of approximately $8.4 million of energy contracts designated as qualifying cash flow hedges and a corresponding unrealized gain of $5.5 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. At September 30, 2006, the Company also had a net liability of approximately $0.2 million related to non-cash flow hedges. Amounts settling after September 30, 2006 have not been deferred as the $40 million cap under the PCA mechanism expired 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 gain of $0.6 million and a loss of $0.2 million through current earnings for the three and nine months ended September 30, 2006, respectively. These mark-to-market adjustments were the result of excluding certain contracts from the normal purchase normal sale exception under SFAS No. 133 and de-designated cash flow hedges where the hedging relationship was ended. At September 30, 2006, the Company also has a net liability of approximately $65.9 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 $4.6 million after-tax and a decrease of $0.4 million on current earnings. 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 September 30, 2006, approximately 98% 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, 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 third quarter 2006, the Company entered into and settled two forward starting interest rate swap contracts. The purpose of the forward starting swap contracts was to hedge interest rate volatility for a debt offering of $300 million that was priced on September 13, 2006. Since interest rates decreased related to the hedged rate, the debt was priced at a rate lower than the hedged rate and PSE paid $0.6 million to the counterparties when the contracts were settled. The forward starting swap contracts were designated and documented under SFAS No. 133 criteria as cash flow hedges, with all changes in market value being presented net of tax in other comprehensive income. In accordance with SFAS No. 133, the loss will be amortized out of other comprehensive income to current earnings as an increase to interest expense over the life of the new debt issued. The ending balance in other comprehensive income related to the forward starting swaps and previously settled treasury lock contracts at September 30, 2006 was a net loss of $8.6 million after-tax and accumulated amortization. All financial hedge contracts of this type are reviewed by senior management and presented to the Securities Pricing Committee of the Board of Directors and are approved prior to execution.

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 September 30, 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 September 30, 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 September 30, 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 September 30, 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 September 30, 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 have been no material changes from the risk factors set forth in Part I, Item 1A in the Company's Annual Report on Form 10-K for the year ended December 31, 2005, as updated by the information discussed under Item 1A of the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2006.

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: November 2, 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:

12.1 Statement setting forth computation of ratios of earnings to fixed charges (2001 through 2005 and 12 months ended September 30, 2006) for Puget Energy.

12.2 Statement setting forth computation of ratios of earnings to fixed charges (2001 through 2005 and 12 months ended September 30, 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.