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

FORM 10-K

/X/ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2006

OR

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

For the transition period from ___________ to ___________

Commission File Number	Exact name of registrant as specified in its charter, state of incorporation, address of principal executive offices, zip code 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

Securities registered pursuant to Section 12(b) of the Act:

	Title Of Each Class	Name Of Each Exchange On Which Listed
Puget Energy, Inc.	Common Stock, $0.01 par value	NYSE
	Preferred Share Purchase Rights	NYSE

Securities registered pursuant to Section 12(g) of the Act:

	Title Of Each Class
Puget Sound Energy, Inc.	Preferred Stock (cumulative, $100 par value)

Puget Sound Energy, Inc. meets the conditions set forth in General Instructions I (1)(a) and (b) of Form 10-K and is therefore filing this Form 10-K with the reduced disclosure format.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Puget Energy, Inc. Yes /X/ No / / Puget Sound Energy, Inc. Yes /X/ No / /

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Puget Energy, Inc. Yes / / No /X/ Puget Sound Energy, Inc. Yes / / No /X/

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. / /

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 Rule 12b-2 of the Act)
Puget Energy, Inc. Yes / / No /X/ Puget Sound Energy, Inc. Yes / / No /X/

The aggregate market value of the voting stock held by non-affiliates of Puget Energy, Inc., computed by reference to the price at which the common stock was last sold, as of the last business day of Puget Energy's most recently completed second fiscal quarter was approximately $2,411,121,000. The number of shares of Puget Energy, Inc.'s common stock outstanding at February 21, 2007 was 116,723,205 shares.

All of the outstanding shares of voting stock of Puget Sound Energy, Inc. are held by Puget Energy, Inc.

Documents Incorporated by Reference

Portions of the Puget Energy, Inc. proxy statement for its 2007 Annual Meeting of Shareholders to be filed with the Commission pursuant to Regulation 14A not later than 120 days after December 31, 2006 are incorporated by reference in Part III hereof.

This Annual Report on Form 10-K is a combined report being filed separately by two different registrants: Puget Energy, Inc. and Puget Sound Energy, Inc. Puget Sound Energy, Inc. makes no representation as to the information contained in this report relating to Puget Energy, Inc. and the subsidiaries of Puget Energy, Inc. other than Puget Sound Energy, Inc. and its subsidiaries.

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DEFINITIONS

AFUDC	Allowance for Funds Used During Construction
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
Dth	Dekatherm (one Dth is equal to one MMBtu)
Ecology	Washington State Department of Ecology
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	Financial Accounting Standards Board Interpretation
FPA	Federal Power Act
IRP	Integrated Resource Plan
InfrastruX	InfrastruX Group, Inc.
kWh	Kilowatt Hour (one kWh equals one thousand watt hours)
LIBOR	London Interbank Offered Rate
LNG	Liquefied Natural Gas
MMBtu	One Million British Thermal Units
MMS	Minerals Management Service of the United States
MW	Megawatt (one MW equals one thousand kW)
MWh	Megawatt Hour (one MWh equals one thousand kWh)
Ninth Circuit	United States Court of Appeals for the Ninth Circuit
NYSE	New York Stock Exchange
PCA	Power Cost Adjustment
PCORC	Power Cost Only Rate Case
PGA	Purchased Gas Adjustment
PG&E	Pacific Gas & Electric Company
PSE	Puget Sound Energy, Inc.
PUDs	Washington Public Utility Districts
Puget Energy	Puget Energy, Inc.
PURPA	Public Utility Regulatory Policies Act
RFP	Request for Proposal
RTO	Regional Transmission Organization
SEC	United States Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
Tenaska	Tenaska Power Fund, L.P.
Washington Commission	Washington Utilities and Transportation Commission
WECO	Western Energy Company

FORWARD-LOOKING STATEMENTS

Puget Energy, Inc. (Puget Energy) and Puget Sound Energy (PSE) are including the following cautionary statements in this Form 10-K 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 and 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, 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;
- Changes in weather conditions in the Pacific Northwest, which could have effects on customer usage and PSE's revenues, thus impacting net income;
- Weather, which can have a potentially serious impact on PSE's 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 God, 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 the quarterly reports on Form 10-Q and current reports on Form 8-K, as well as Item 1A-"Risk Factors" on this Form 10-K.

PART I

ITEM 1. BUSINESS

GENERAL

Puget Energy, Inc. (Puget Energy) is an energy services holding company incorporated in the state of Washington in 1999. All of its operations are conducted through its subsidiary, Puget Sound Energy, Inc. (PSE), a utility company. Puget Energy has no significant assets other than the stock of PSE. On May 7, 2006, Puget Energy sold its 90.9% interest in InfrastruX Group, Inc. (InfrastruX) and therefore the financial position and results of operations for InfrastruX are presented as discontinued operations. Puget Energy and PSE are collectively referred to herein as "the Company." The following table provides the percentages of Puget Energy's consolidated continuing operating revenues and net income generated and assets held by the operating segments:

Segment	Percent of Revenue			Percent of Net Income			Percent of Assets		
	2006	2005	2004	2006	2005	2004	2006	2005	2004
Puget Sound Energy	99.7%	99.7%	99.7%	103.3%	91.7%	224.2%	99.0%	94.8%	94.2%
InfrastruX[1,2]	0%	0%	0%	0%	6.1%	(127.8)%	0%	4.2%	4.6%
Other[3]	0.3%	0.3%	0.3%	(3.3)%	2.2%	3.6%	1.0%	1.0%	1.2%

1 *InfrastruX is presented on a discontinued operations basis beginning in 2005 and therefore does not present operating revenue. Operating revenue in 2004 has been reclassified as discontinued operations.*

2 *In 2004, Puget Energy recorded Goodwill impairment of $76.6 million after-tax which resulted in a loss at InfrastruX.*

3 *Includes subsidiaries of PSE and Puget Energy holding company operations. 2006 includes the impact of the establishment and funding of a charitable foundation.*

PUGET ENERGY STRATEGY

Puget Energy is the parent company of the largest electric and natural gas utility headquartered in the state of Washington, primarily engaged in the business of electric transmission, distribution, generation and natural gas transmission and distribution. Puget Energy's business strategy is to generate stable earnings and cash flow by offering reliable electric and gas service in a cost effective manner through PSE.

PUGET SOUND ENERGY, INC.

PSE is a public utility incorporated in the state of Washington in 1960. PSE furnishes electric and gas service in a territory covering approximately 6,000 square miles, principally in the Puget Sound region of the state of Washington.

At December 31, 2006, PSE had approximately 1,039,400 electric customers, consisting of 918,200 residential, 114,600 commercial, 3,800 industrial and 2,800 other customers; and approximately 713,000 gas customers, consisting of 658,100 residential, 52,100 commercial, 2,700 industrial and 100 transportation customers. At December 31, 2006, approximately 342,200 customers purchased both electricity and gas from PSE. In 2006, PSE added approximately 21,300 electric customers and 19,400 gas customers, representing annualized customer growth rates of 2.1% and 2.8%, respectively. During 2006, PSE's billed retail and transportation revenues from electric utility operations were derived 49.3% from residential customers, 42.8% from commercial customers, 6.3% from industrial customers and 1.6% from other customers. PSE's retail revenues from gas utility operations were derived 63.2% from residential customers, 30.4% from commercial customers, 5.2% from industrial customers and 1.2% from transportation customers in 2006. During this period the largest customer accounted for approximately 1.2% of PSE's operating revenues.

PSE is affected by various seasonal weather patterns and therefore, utility revenues and associated expenses are not generated evenly during the year. Energy usage varies seasonally and monthly primarily as a result of weather conditions. PSE experiences its highest retail energy sales in the first and fourth quarters of the year. Sales of electricity to wholesale customers also vary by quarter and year depending principally upon fundamental market factors and weather conditions. PSE has a purchased gas adjustment (PGA) mechanism in retail gas rates to recover variations in gas supply and transportation costs. PSE also has a power cost adjustment (PCA) mechanism in electric rates to recover variations in electricity costs on a shared basis with customers.

In the five-year period ended December 31, 2006, PSE's gross electric utility plant additions were $1.5 billion and retirements were $300.6 million. In the same five-year period, PSE's gross gas utility plant additions were $686.7 million and retirements were $92.1 million. In the same five-year period, PSE's gross common utility plant additions were $273.6 million and retirements were $50.3 million. Gross electric utility plant at December 31, 2006 was approximately $5.3 billion, which consisted of 54.2% distribution, 31.6% generation, 6.2% transmission and 8.0% general plant and other. Gross gas utility plant at December 31, 2006 was approximately $2.1 billion, which consisted of 93.0% distribution and 7.0% general plant and other. Gross common utility general and intangible plant at December 31, 2006 was approximately $458.3 million.

INFRASTRUX GROUP, INC.

InfrastruX, a non-regulated construction services business, was incorporated in the state of Washington in 2000. On May 7, 2006, Puget Energy sold its 90.9% interest in InfrastruX to an affiliate of Tenaska Power Fund, L.P. (Tenaska). Puget Energy accounted for InfrastruX as a discontinued operation.

EMPLOYEES

At February 21, 2007, Puget Energy had no employees and PSE had approximately 2,400 full-time employees. Approximately 1,142 PSE employees are represented by the International Brotherhood of Electrical Workers Union (IBEW) or the United Association of Plumbers and Pipefitters (UA). The current labor contracts with the IBEW and UA run through March 31, 2007 and September 30, 2010, respectively. The Company is currently in contract discussions with the IBEW.

CORPORATE LOCATION

Puget Energy's and PSE's principal executive offices are located at 10885 NE 4th Street, Suite 1200, Bellevue, Washington 98004 and the telephone number is (425) 454-6363.

AVAILABLE INFORMATION

The Company's reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available or may be accessed free of charge through the Investors section of the Company's website at www.pugetenergy.com after the reports are electronically filed with, or furnished to, the United States Securities and Exchange Commission (SEC). Information may also be obtained via the SEC Internet website at www.sec.gov.

In addition, the following corporate governance materials of the Company are available in the Investors section of the Company's website and a copy will be mailed upon request. Requests should be made to Puget Energy, Inc., Investor Services, P.O. Box 97034, PSE-08N, Bellevue, Washington 98009-9734.

- Corporate Governance Guidelines;
- Corporate Ethics and Compliance Code;
- Charters of Board Committees; and
- Code of Ethics for the Company's Chief Executive Officer and senior financial officers.

If the Company waives any material provision of its Code of Ethics for its Chief Executive Officer (CEO) and senior financial officers or its Corporate Ethics and Compliance Code, or substantively changes the codes for any specific officer, the Company will disclose that waiver on its website within four business days.

NEW YORK STOCK EXCHANGE CERTIFICATION

On May 24, 2006, the CEO of Puget Energy and PSE filed a Section 303A.12(a) CEO Certification with the New York Stock Exchange (NYSE). The CEO Certification attests that the CEO is not aware of any violations by the Company of the NYSE's Corporate Governance Listing Standards.

REGULATION AND RATES

PSE is subject to the regulatory authority of: (1) the Federal Energy Regulatory Commission (FERC) with respect to the transmission of electric energy, the resale of electric energy at wholesale, accounting and certain other matters; and (2) the Washington Utilities and Transportation Commission (Washington Commission) as to retail rates, accounting, the issuance of securities and certain other matters.

FEDERAL REGULATION

FERC Order No. 2000, issued on December 20, 1999, required all utilities subject to its jurisdiction that own, operate or control transmission facilities to either voluntarily form or participate in a Regional Transmission Organization (RTO) or Independent System Operator (ISO); or, alternatively, to describe its efforts to participate in an RTO/ISO or the obstacles to such participation. PSE had been an active participant in regional efforts to form an RTO/ISO in the Pacific Northwest since the issuance of Order No. 2000. PSE has continued to work with BPA and other regional transmission owners to address the transmission related issues in the region via a new organization known as ColumbiaGrid.

The Energy Policy Act of 2005 (EPAct 2005) added a requirement for FERC to certify an Electric Reliability Organization (ERO) to develop mandatory and enforceable electric system reliability standards. FERC has certified the North American Electric Reliability Corporation (NERC) as the ERO to develop these standards subject to FERC review and approval. Once approved, the reliability standards will apply to PSE and will be enforced by the ERO subject to FERC oversight. PSE expects the standards to become mandatory in June 2007. Failure to comply with these reliability standards once they become mandatory could result in a financial penalty.

STATE REGULATION

PSE's retail electric service is fully regulated by the Washington Commission. PSE is not aware of any proposals or prospects for retail deregulation in the state of Washington.

PSE's retail gas service is also regulated by the Washington Commission. Since 1986, PSE has been offering gas transportation as a separate service to industrial and commercial customers who choose to purchase their gas supply directly from producers and gas marketers. The shifting of customers between sales and transportation service does not materially impact utility margin, as PSE earns similar margins on transportation service and large-volume, interruptible gas sales.

ELECTRIC REGULATION AND RATES

Power Cost Adjustment Mechanism. On June 20, 2002, the Washington Commission approved a PCA mechanism that triggers if PSE's costs to provide electricity falls outside certain bands established in an electric rate case. The cumulative maximum pre-tax earnings exposure due to power cost variations over the four-year period ending June 30, 2006 was limited to $40.0 million plus 1.0% of the excess. In October 2005, the Washington Commission approved a shift to an annual PCA measurement period from January through December starting in 2007. On January 5, 2007, the Washington Commission approved the PCA mechanism for continuation under the same annual graduated scale without a cumulative cap for excess power costs. All significant variable power supply cost variables (hydroelectric and wind generation, market price for purchased power and surplus power, natural gas and coal fuel price, generation unit forced outage risk and transmission cost) are included in the PCA mechanism.

The PCA mechanism apportions increases or decreases in power costs, on a calendar year basis, between PSE and its customers on a graduated scale:

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 allowed for a reduction to 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 $40.0 million plus 1.0% of the excess. Power cost variation after December 31, 2006 will be apportioned on a calendar year basis, without a cumulative cap.*

Electric General Rate Case. On January 5, 2007, the Washington Commission issued its order in PSE's electric general rate case filed in February 2006, approving a general rate decrease for electric customers of $22.8 million or 1.3% annually. The rates for electric customers were effective January 13, 2007. In its order, the Washington Commission approved a weighted cost of capital of 8.4%, or 7.06% after-tax, and a capital structure that included 44.0% common equity with a return on equity of 10.4%. The Washington Commission had earlier approved (on June 28, 2006) a power cost only rate case (PCORC) increase of $96.1 million annually effective July 1, 2006.

Power Cost Only Rate Case. A limited-scope proceeding called a PCORC was created in 2002 by the Washington Commission to periodically reset power cost rates. The main objective of the PCORC proceeding is to provide for timely review of new resource acquisitions costs and inclusion of such costs in rates at the time the new resource goes into service. To achieve this objective, the Washington Commission agreed to an expedited five-month PCORC decision timeline rather than the statutory 11-month timeline for a general rate case.

On October 20, 2005, the Washington Commission approved a PCORC filing that increased electric rates 3.7% or $55.6 million annually. Included in the increase is the recovery of capital and operating costs of the Hopkins Ridge wind generating facility. The Hopkins Ridge wind generating facility was completed on November 27, 2005. As a wind generating facility, Hopkins Ridge is eligible for Federal Production Tax Credits (PTCs) that will ultimately offset some of the costs associated with generating power from Hopkins Ridge. The PTC is a tax credit provided by the federal government for generating electricity from certain renewable resources. The current amount of the tax credit is $0.019 per kilowatt hour (kWh) for wind generation and may be subject to inflation adjustments over time. The tax credit can be claimed for 10 years for a new wind project put into service prior to January 1, 2008. The use of the credit is restricted to offset only 25.0% of current taxes payable. Unused credits can be carried forward for up to 20 years. In the Washington Commission's October 2005 order, a new tariff schedule was approved which provides for the pass through to ratepayers of all benefits of the PTCs of the Hopkins Ridge project. This mechanism (a PTC Tracker) will pass through to the customer the actual PTCs of the Hopkins Ridge project as they are generated. The PTC Tracker would not be subject to the sharing bands in the PCA. The credits passed through to the customer will be adjusted by the carrying costs of unused PTCs. Since the customer is receiving the benefit of the tax credits as they are generated and the Company does not receive a credit from the IRS until the tax credits are utilized, the Company is reimbursed its carrying costs for funds through this calculation.

GAS REGULATION AND RATES

Gas General Rate Case. On January 5, 2007, the Washington Commission issued its order in PSE's gas general rate case, granting an increase in gas rates of $29.5 million or 2.8% annually, effective January 13, 2007. In its order the Washington Commission approved the same weighted cost of capital of 8.4%, or 7.06% after-tax, and capital structure that included 44.0% common equity with a return on equity of 10.4%, as allowed for the Company's electric operations.

Purchased Gas Adjustment. PSE has a purchased gas adjustment (PGA) mechanism in retail gas rates to recover variations in gas supply and transportation costs. Variations in gas rates are passed through to customers, therefore PSE's gas margin and net income are not affected by such variations. On September 27, 2006, the Washington Commission approved a revision of PSE's PGA tariff schedule that went into effect on October 1, 2006. The tariff changes will increase gas revenue approximately $95.1 million, or 10.2%, 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 following rate adjustments were approved by the Washington Commission in relation to the PGA mechanism during 2006, 2005 and 2004:

Effective Date	Percentage Increase in Rates	Annual Increase in Revenues (Dollars In Millions)
October 1, 2006	10.2%	$ 95.1
October 1, 2005	14.7%	121.6
October 1, 2004	17.6%	121.7

ELECTRIC UTILITY OPERATING STATISTICS

Twelve Months ended December 31	2006	2005	2004
Generation and purchased power, MWh			
Company-controlled resources	6,845,323	6,902,040	7,048,270
Contracted resources	9,625,381	9,606,880	9,421,546
Non-firm energy purchased	8,185,198	7,299,139	6,164,457
Total generation and purchased power	24,655,902	23,808,059	22,634,273
Less: losses and Company use	(1,489,008)	(1,448,214)	(1,432,686)
Total energy sales, MWh	23,166,894	22,359,845	21,201,587

Twelve Months ended December 31	2006	2005	2004
Electric energy sales, MWh			
Residential	10,593,340	10,321,984	10,028,150
Commercial	8,939,155	8,647,478	8,449,566
Industrial	1,368,672	1,357,973	1,352,660
Other customers	78,078	105,388	94,034
Total energy billed to customers	20,979,245	20,432,823	19,924,410
Unbilled energy sales – net increase (decrease)	119,800	40,015	(40,217)
Total energy sales to customers	21,099,045	20,472,838	19,884,193
Sales to other utilities and marketers	2,067,849	1,887,007	1,317,394
Total energy sales, MWh	23,166,894	22,359,845	21,201,587
Transportation, including unbilled	2,091,981	2,030,457	1,988,965
Electric energy sales and transportation, MWh	25,258,875	24,390,302	23,190,552

Twelve Months ended December 31	2006	2005	2004
Electric operating revenues by classes (thousands):			
Residential	$ 788,237	$ 690,184	$ 628,869
Commercial	702,754	629,008	580,973
Industrial	103,043	93,922	88,779
Other customers	66,470	76,153	58,007
Operating revenues billed to customers[1]	1,660,504	1,489,267	1,356,628
Unbilled revenues – net increase (decrease)	20,749	9,548	(813)
Total operating revenues from customers	1,681,253	1,498,815	1,355,815
Transportation, including unbilled	11,488	9,027	10,707
Sales to other utilities and marketers	85,004	105,027	56,512
Total electric operating revenues	$ 1,777,745	$ 1,612,869	$ 1,423,034

TWELVE MONTHS ENDED DECEMBER 31	2006	2005	2004
Number of customers served (average):			
Residential	909,876	893,576	877,711
Commercial	111,672	111,587	109,238
Industrial	3,696	3,877	3,980
Other	2,637	2,426	2,197
Transportation	18	17	17
Total customers (average)	1,027,899	1,011,483	993,143

TWELVE MONTHS ENDED DECEMBER 31	2006	2005	2004
Average kWh used per customer:			
Residential	11,643	11,551	11,425
Commercial	80,048	77,495	77,350
Industrial	370,312	350,264	339,864
Other	29,609	43,441	42,801
Average revenue billed per customer:			
Residential	$ 866	$ 772	$ 716
Commercial	6,293	5,637	5,318
Industrial	27,880	24,225	22,306
Other	25,207	31,390	26,403
Average retail revenues per kWh sold:			
Residential	$ 0.0744	$ 0.0669	$ 0.0627
Commercial	0.0786	0.0727	0.0688
Industrial	0.0753	0.0692	0.0656
Average retail revenue per kWh sold	0.0763	0.0695	0.0655
Heating degree days	4,476	4,489	4,421
Percent of normal – NOAA 30-year average	93.3%	93.6%	91.8%
Load factor[2]	52.4%	57.4%	53.5%

1 *Operating revenues in 2004 were reduced by $0.8 million as a result of the Company's sale of $237.7 million of its investment in customer-owned conservation measures in 1995 and 1997. As of October 2004, the bond was paid and any excess collections were recorded as a reduction in revenues.*

2 *Average usage by customers divided by their maximum usage.*

ELECTRIC SUPPLY

At December 31, 2006, PSE's electric power resources had a total capacity of approximately 4,456 megawatts (MW). PSE's historical peak load of approximately 4,847 MW occurred on December 21, 1998. In order to meet an extreme winter peak load, PSE may supplement its electric power resources with winter-peaking call options and other instruments that may include, but are not limited to, weather-related hedges and exchange agreements. When it is more economical to purchase power than to run the Company's generation, PSE will purchase in the short-term markets.

The following table shows PSE's electric energy supply resources at December 31, 2006 and 2005 and energy production during the year:

	Peak Power Resources At December 31				Energy Production			
	2006		2005		2006		2005	
	MW	%	MW	%	MWh	%	MWh	%
Purchased resources:								
Columbia River PUD contracts	1,164	26.1%	1,212	28.3%	5,692,366	23.1%	5,397,825	22.7%
Other hydroelectric[1]	168	3.8%	164	3.8%	653,362	2.6%	590,263	2.5%
Other producers[1]	932	20.9%	944	22.1%	3,279,575	13.3%	3,618,792	15.2%
Short-term wholesale energy purchases[2]	N/A	N/A	N/A	N/A	8,185,276	33.2%	7,299,139	30.7%
Total purchased	2,264	50.8%	2,320	54.2%	17,810,579	72.2%	16,906,019	71.1%
Company-controlled resources:								
Hydroelectric	234	5.3%	234	5.5%	949,276	3.9%	879,493	3.7%
Coal	677	15.2%	677	15.8%	4,800,028	19.5%	5,175,799	21.7%
Natural gas/oil	902	20.2%	902	21.0%	723,190	2.9%	813,078	3.4%
Wind[3]	379	8.5%	150	3.5%	372,829	1.5%	33,670	0.1%
Total Company-controlled	2,192	49.2%	1,963	45.8%	6,845,323	27.8%	6,902,040	28.9%
Total	4,456	100.0%	4,283	100.0%	24,655,902	100.0%	23,808,059	100.0%

1 *Power received from other utilities is classified between hydroelectric and other producers based on the character of the utility system used to supply the power or, if the power is supplied from a particular resource, the character of that resource.*

2 *Short-term wholesale purchases net of resale of 2,067,849 MWh and 1,887,007 MWh account for 27.1% and 24.7% of energy production for 2006 and 2005, respectively.*

3 *2006 represents Hopkins Ridge and Wild Horse wind projects. Wild Horse began commercial operations on December 22, 2006. 2005 represents Hopkins Ridge, which began commercial operations on November 27, 2005.*

Integrated Resource Plans

PSE is required by the Washington Commission to file electric and gas Integrated Resource Plans (IRP) every two years. The next plan will be filed in May 2007. PSE filed its electric IRP in May 2005 that supports a strategy of diverse electric power and demand resource acquisitions including resources fueled by natural gas and coal, renewable resources (e.g., wind and biomass) and the implementation of energy efficiency strategies. The electric IRP was followed by an all-source request for proposal (RFP) issued on November 1, 2005. The Washington Commission approved the all-source RFP on October 28, 2005. Based on PSE's projected customer usage for electricity and its current electric generation resources, PSE expects that future energy needs will exceed current purchased and Company-controlled power resources. The expected average MW shortfall for the period 2007 through 2011 is as follows:

	2007	2008	2009	2010
Projected average MW shortfall[1]	283	305	362	457

1 *Estimated using all resources under long-term contracts and Company-controlled facilities.*

PSE expects to address this shortfall position with the use of a combination of new long-term power contracts and the purchase or construction of new generating resources.

COMPANY – CONTROLLED ELECTRIC GENERATION RESOURCES

At December 31, 2006, PSE has the following plants with an aggregate net generating capacity of 2,192 MW:

PLANT NAME	PLANT TYPE	NET CAPACITY (MW)	YEAR INSTALLED
Colstrip Units 1 & 2 (50% interest)	Coal	307	1975 & 1976
Colstrip Units 3 & 4 (25% interest)	Coal	370	1984 & 1986
Fredonia Units 1 & 2	Dual-fuel combustion turbines	207	1984
Frederickson Units 1 & 2	Dual-fuel combustion turbines	147	1981
Whitehorn Units 2 & 3	Dual-fuel combustion turbines	147	1981
Fredonia Units 3 & 4	Dual-fuel combustion turbines	107	2001
Frederickson Unit 1 (49.85% interest)	Natural gas combined cycle	124	2002
Encogen	Natural gas cogeneration	167	1993
Crystal Mountain	Internal combustion	3	1969
Upper Baker River	Hydroelectric	91	1959
Lower Baker River	Hydroelectric	79	1925; reconstructed 1960; upgraded 2001
Snoqualmie Falls	Hydroelectric	44	1898 to 1911 & 1957
Electron	Hydroelectric	22	1904 to 1929
Wild Horse	Wind	229	2006
Hopkins Ridge	Wind	150	2005
Total Net Capacity		2,194	

GOLDENDALE GENERATING STATION

On February 21, 2007, PSE acquired the Goldendale Generating Station, a 277 MW capacity natural gas generating facility in the state of Washington, from the Calpine Corporation through its bankruptcy proceeding. PSE paid $120.0 million for the generating facility.

FERC HYDROELECTRIC PROJECTS AND LICENSES

As part of its hydroelectric operations, PSE is required to obtain operating licenses from FERC. A typical license contains mandatory conditions of operation, such as flow rate requirements, adherence to certain ramping protocols for outages, maintenance of reservoir levels, equipment upgrade projects and fish and wildlife mitigation projects for a 30 to 50 year period. The licensing and relicensing processes involve harmonizing conflicting rights and obligations of numerous governmental, non-governmental and private parties, and dealing with issues that may include environmental compliance, fish protection and mitigation, water quality, Native American rights, title claims, operational and capital improvements and flood control. As a result, a number of political, compliance and financial risks can arise from the licensing and relicensing processes. FERC regulates dam safety and administers proceedings under the Federal Power Act (FPA) to license jurisdictional hydropower projects.

PSE owns three operating hydroelectric projects: the Baker River project, the Snoqualmie Falls project and the Electron project. PSE's White River project ceased operations as a hydroelectric generating resource in January 2004. The Baker River and Snoqualmie Falls projects are operating under the jurisdiction of FERC.

Baker River project. The Baker River project's current annual 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, (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 $360.0 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 additional regulatory approvals yet to be attained from various agencies and other contingencies that have yet to be resolved. A Final Environmental Impact Statement was issued by FERC on September 8, 2006. However, FERC has not yet ruled on the proposed settlement and its ultimate outcome remains uncertain.

Snoqualmie Falls project. The Snoqualmie Falls project was granted a new 40-year operating license by FERC on June 29, 2004. PSE estimates that the investment required to implement the conditions of the new license will cost approximately $44.0 million. On July 29, 2004, the Snoqualmie Tribe 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. Appeals to the U.S. Court of Appeals by the Snoqualmie Tribe and by PSE have been consolidated. Oral arguments were held on February 8, 2007. An adverse ruling from the Court or adverse action by FERC if the license issuance is remanded could impact PSE's future use of this generating asset.

White River project. The White River project was operated as a hydropower facility until 2004. PSE is actively seeking to sell the project and the municipal water rights associated with the project to one or more entities. In June 2003, Ecology approved an application for new municipal water rights related to the White River project reservoir. After an appeal in July 2004, this decision was remanded back to Ecology for further analysis of non-hydropower operations. On December 21, 2006, PSE entered into a Purchase and Sale Agreement with the Cascade Land Conservancy to sell certain rights and interests in a portion of former project properties, although the closing of the sale is subject to contingencies that have yet to be resolved.

On April 7, 2004, the Washington Commission approved PSE's recovery on the unamortized White River plant investment. At December 31, 2006, the White River project net book value totaled $69.1 million, which included $43.4 million of net utility plant, $17.1 million of capitalized FERC licensing costs, $4.3 million of costs related to construction work in progress and $1.8 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. Any proceeds from the sale of the White River assets and water rights will reduce the balance of the deferred regulatory asset. Neither the outcome of this matter nor any potential associated financial impacts can be predicted at this time.

COLUMBIA RIVER ELECTRIC ENERGY SUPPLY CONTRACTS

During 2006, approximately 23.1% of PSE's energy output was obtained at an average cost of approximately $0.014 per kWh through long-term contracts with several of the Washington PUDs that own and operate hydroelectric projects on the Columbia River. PSE agrees to pay a proportionate share of the annual debt service, operating and maintenance costs and other expenses associated with each project. PSE's payments are not contingent upon the projects being operable.

As of December 31, 2006, the Company was entitled to purchase portions of the power output of the PUDs' projects as set forth:

Project	Contract Exp. Date	License Exp. Date	Company's Annual Amount Purchasable (Approximate) % of Output	Company's Annual Amount Purchasable (Approximate) Megawatt Capacity
Chelan County PUD:[1]				
Rock Island Project				
Original units	2012	2029	50.0	330
Additional units	2012	2029	50.0	
Rocky Reach Project	2011	2006	38.9	501
Douglas County PUD:				
Wells Project	2018	2012	29.9	251
Grant County PUD:[2,3]				
Priest Rapids Development	TBD	TBD	4.3	39
Wanapum Development	2009	TBD	10.8	106
Total				1,227

1 *On February 3, 2006, PSE and Chelan entered into a new Power Sales Agreement and a related Transmission Agreement for 25.0% of the output of Chelan's Rocky Reach and Rock Island hydro electric generating facilities located on the mid-Columbia River in exchange for PSE paying 25.0% 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). PSE made a non-refundable capacity reservation payment of $89.0 million as required by the agreements. The Washington Commission determined the prudence of PSE entering into the new Chelan contract and confirmed the treatment of the $89.0 million as a regulatory asset as part of its order in PSE's General Rate Case on January 5, 2007.*

2 *Under terms of the 2001 Grant contract extensions, PSE will continue to obtain capacity and energy for the term of any new FERC license to be obtained by Grant County PUD. The new contracts' terms began in November of 2005 for the Priest Rapids Development and will begin in November of 2009 for the Wanapum Development.*

3 *PSE's share of power from the 2001 contract declines over time as Grant County PUD's load increases. PSE's share of the Wanapum Development will remain at 10.8% until November 2009 and will be adjusted annually thereafter for the remaining term of the new contracts. PSE's share of the Priest Rapids Development declined to approximately 4.3% in 2006 and will be adjusted annually for the remaining term of the new contract.*

ELECTRIC ENERGY SUPPLY CONTRACTS AND AGREEMENTS WITH OTHER UTILITIES

PSE has entered into long-term firm purchased power contracts with other utilities in the West region. PSE is generally not obligated to make payments under these contracts unless power is delivered.

Under a 1985 settlement agreement with Bonneville Power Administration (BPA), PSE is entitled to receive exchange energy from BPA during the months of November through April, which amounts to 36.5 average MW of energy and 82 MW of capacity for contract year 2006-2007. BPA has an option to request that PSE deliver up to 31.2 average MW of exchange energy to BPA in all months except May, July and August for contract year 2006-2007. The contract terminates June 30, 2017, but may be terminated earlier under certain circumstances.

On October 1, 1989, PSE signed a contract with The Montana Power Company for 71 average MW of energy (97 MW of peak capacity) through December 2010. The contract deliveries are contingent on the combined availability of Colstrip Units 3 & 4. The contract payments consist of a fixed monthly payment and an energy payment based on commodity and transportation costs for coal. The fixed payment may be reduced if the delivered energy is less than the adjusted energy entitlement (equal to an equivalent availability of approximately 73.0%) for the contract year.

In January 1992, PSE executed an agreement with Pacific Gas & Electric Company (PG&E) to exchange 300 MW of capacity together with up to 413,000 megawatt hours (MWh) of energy seasonally each year. No payments are made under this agreement. PG&E provides power during the months of November through February and PSE provides power during the months of June through September. Each party may terminate the contract upon five year prior notice.

Under an agreement with Powerex expiring in February 2006, Powerex pays PSE for the right to deliver up to 1,200,000 MWh annually to PSE at the Canadian border in exchange for PSE delivering power to Powerex at various locations in the United States. The agreement also allows Powerex to make up any exchange volumes not used up to two years after the end of the annual period.

ELECTRIC ENERGY SUPPLY CONTRACTS AND AGREEMENTS WITH NON-UTILITY GENERATORS

As required by the federal Public Utility Regulatory Policies Act (PURPA), PSE has entered into long-term firm purchased power contracts with non-utility generators. The most significant contracts are described below. PSE purchases the net electrical output of these three projects at fixed and annually escalating prices, intended to approximate PSE's avoided cost of new generation projected at the time these agreements were made.

As of December 31, 2006, the Company purchased the power output from the following:

CONTRACT	PLANT TYPE	CONTRACT EXP. DATE	MEGAWATT CAPACITY	AVERAGE MEGAWATTS OF ENERGY
Sumas Cogeneration Company	Natural gas cogeneration	2013	135	108
March Point Cogeneration Company:				
March Point Phase I	Natural gas cogeneration	2011	80	70
March Point Phase II	Natural gas cogeneration	2011	60	53
Tenaska Washington Partners, LP	Natural gas cogeneration	2011	245	216
Total			520	447

ELECTRIC TRANSMISSION CONTRACTS WITH OTHER UTILITIES

PSE has entered into numerous transmission contracts with BPA to integrate electric generation and contracted resources into PSE's system. These transmission contracts require PSE to pay for transmission service based on the contracted MW level of demand, regardless of actual use. Any costs incurred are recovered through the PCA mechanism.

Other agreements provide actual capacity ownership or capacity ownership rights. PSE's annual charges are also based on contracted MW volumes. Capacity on these agreements that is not committed is available for sale to third parties on PSE's Open Access Same Time Information System (OASIS). PSE purchases short term transmission services from a variety of providers, including BPA.

The transmission agreements with BPA have various terms and collectively and have an aggregate demand limit in excess of 2,600 MW.

In 2006, BPA and PSE signed agreements for a total of 650 MW from the Mid-Columbia area into PSE's system. Service under these agreements commenced November 1, 2006 and will continue until November 30, 2007 and contain rights to continue service beyond the termination date.

GAS UTILITY OPERATING STATISTICS

TWELVE MONTHS ENDED DECEMBER 31	2006	2005	2004
Gas operating revenues by classes (thousands):			
Residential	$ 697,631	$ 592,361	$ 478,969
Commercial firm	279,977	234,342	187,262
Industrial firm	43,994	38,380	30,472
Interruptible	68,753	56,928	46,900
Total retail gas sales	1,090,355	922,011	743,603
Transportation services	13,269	13,277	12,968
Other	16,494	17,227	12,735
Total gas operating revenues	$ 1,120,118	$ 952,515	$ 769,306

TWELVE MONTHS ENDED DECEMBER 31	2006	2005	2004
Number of customers served (average):			
Residential	649,373	629,563	610,181
Commercial firm	51,007	50,148	49,050
Industrial firm	2,618	2,651	2,688
Interruptible	470	528	574
Transportation	122	129	129
Total customers	703,590	683,019	662,622

TWELVE MONTHS ENDED DECEMBER 31	2006	2005	2004
Gas volumes, therms (thousands):			
Residential	533,370	510,026	489,036
Commercial firm	236,753	225,389	217,346
Industrial firm	41,185	38,576	36,751
Interruptible	65,016	61,769	65,425
Total retail gas volumes, therms	876,324	835,760	808,558
Transportation volumes	206,367	198,504	201,642
Total volumes	1,082,691	1,034,264	1,010,200

TWELVE MONTHS ENDED DECEMBER 31	2006	2005	2004
Working gas volumes in storage at year end, therms (thousands):			
Jackson Prairie	68,141	70,303	70,986
AECO hub - Canada	14,810	14,820	--
Clay Basin	91,090	38,857	55,044
Average therms used per customer:			
Residential	821	810	801
Commercial firm	4,642	4,494	4,431
Industrial firm	15,731	14,551	13,672
Interruptible	138,332	116,987	113,981
Transportation	1,691,533	1,538,791	1,563,116
Average revenue per customer:			
Residential	$ 1,074	$ 941	$ 785
Commercial firm	5,489	4,673	3,818
Industrial firm	16,804	14,478	11,336
Interruptible	146,283	107,818	81,707
Transportation	108,762	102,922	100,527
Average revenue per therm sold:			
Residential	$ 1.308	$ 1.161	$ 0.979
Commercial firm	1.183	1.040	0.862
Industrial firm	1.068	0.995	0.829
Interruptible	1.057	0.922	0.717
Average retail revenue per therm sold	1.244	1.103	0.920
Transportation	0.064	0.067	0.064
Heating degree days	4,476	4,489	4,421
Percent of normal – NOAA 30-year average	93.3%	93.6%	91.8%

GAS SUPPLY

PSE currently purchases a blended portfolio of gas supplies ranging from long-term firm to daily from a diverse group of major and independent natural gas producers and marketers in the United States and Canada. PSE also enters into short-term physical and financial fixed price derivative instruments to hedge the cost of gas to serve its customers. All of PSE's gas supply is ultimately transported through the facilities of Williams Northwest Pipeline Corporation (NWP), the sole interstate pipeline delivering directly into western Washington. Delivery of gas supply to PSE's gas system is therefore dependent upon the operations of NWP.

	2006		2005	
PEAK FIRM GAS SUPPLY AT DECEMBER 31	Dth per Day	%	Dth per Day	%
Purchased gas supply:				
British Columbia	235,000	24.3%	205,400	22.1%
Alberta	60,000	6.2%	60,000	6.5%
United States	145,700	15.1%	167,800	18.1%
Total purchased gas supply	440,700	45.6%	433,200	46.7%
Purchased storage capacity:				
Clay Basin	76,000	7.9%	45,200	4.9%
Jackson Prairie	55,100	5.7%	55,100	5.9%
AECO hub - Canada	16,700	1.7%	16,700	1.8%
Liquefied natural gas	70,500	7.3%	70,500	7.6%
Total purchased storage capacity	218,300	22.6%	187,500	20.2%
Owned storage capacity:				
Jackson Prairie	294,700	30.5%	294,700	31.8%
Propane-air and other	12,500	1.3%	12,500	1.3%
Total owned storage capacity	307,200	31.8%	307,200	33.1%
Total peak firm gas supply	966,200	100%	927,900	100.0%
Other and commitments with third parties	(44,400)		(41,400)	
Total net peak firm gas supply	921,800		886,500	

All peak firm gas supplies and storage are connected to PSE's market with firm transportation capacity.

For baseload and peak-shaving purposes, PSE supplements its firm gas supply portfolio by purchasing natural gas, injecting it into underground storage facilities and withdrawing it during the peak winter heating season. Storage facilities at Jackson Prairie in western Washington and at Clay Basin in Utah are used for this purpose. Jackson Prairie is also used for daily balancing of load requirements on PSE's gas system. Peaking needs are also met by using PSE-owned gas held in NWP's liquefied natural gas (LNG) facility at Plymouth, Washington, by producing propane-air gas at a plant owned by PSE and located on its distribution system, and by interrupting service to customers on interruptible service rates.

PSE expects to meet its firm peak-day requirements for residential, commercial and industrial markets through its firm gas purchase contracts, firm transportation capacity, firm storage capacity and other firm peaking resources. PSE believes it will be able to acquire incremental firm gas supply to meet anticipated growth in the requirements of its firm customers for the foreseeable future.

GAS SUPPLY PORTFOLIO

For the 2006-2007 winter heating season, PSE contracted approximately 24.3% of its expected peak-day gas supply requirements from sources originating in British Columbia, Canada under a combination of long-term, medium-term and seasonal purchase agreements. Long-term gas supplies from Alberta represent approximately 6.2% of the peak-day requirements. Long-term and winter peaking arrangements with U.S. suppliers make up approximately 15.1% of the peak-day portfolio. The balance of the peak-day requirements is expected to be met with gas stored at Jackson Prairie, Clay Basin and AECO hub (AECO), LNG held at NWP's Plymouth facility and propane-air and other resources, which represent approximately 36.2%, 7.9%, 1.7%, 7.3% and 1.3%, respectively, of expected peak-day requirements. PSE also has the ability to curtail service to industrial and commercial customers on interruptible service rates during a peak-day event. The December 2006 firm gas supply portfolio consisted of arrangements with 20 producers and gas marketers, with no single supplier representing more than 6.0% of expected peak-day requirements. Contracts have remaining terms ranging from less than 1 year to 8 years.

During 2006, approximately 37.9% of gas supplies purchased by PSE originated in British Columbia while 18.4% originated in Alberta and 43.7% originated in the United States. PSE's firm gas supply portfolio has flexibility in its transportation arrangements so that some savings can be achieved when there are regional price differentials between gas supply basins. The geographic mix of suppliers and daily, monthly and annual take requirements permit some degree of flexibility in managing gas supplies during off-peak periods to minimize costs. Gas is marketed outside PSE's service territory (off-system sales) whenever on-system customer demand requirements permit.

GAS STORAGE CAPACITY

PSE holds storage capacity in the Jackson Prairie and Clay Basin underground gas storage facilities adjacent to NWP's pipeline and at AECO in Alberta, Canada adjacent to Nova Gas Transmission, Ltd. (TransCanada-Alberta). These facilities represent 45.8% of the expected peak-day portfolio. The Jackson Prairie facility, operated and one-third owned by PSE, is used primarily for intermediate peaking purposes since it is able to deliver a large volume of gas over a relatively short time period. Combined with capacity contracted from NWP's one-third stake in Jackson Prairie, PSE has peak firm delivery capacity of over 349,000 Dekatherm (one Dekatherm, or Dth, is equal to one million British thermal units or MMBtu) per day and total firm storage capacity of over 8,600,000 Dth at the facility. The location of the Jackson Prairie facility in PSE's market area increases supply reliability and provides significant pipeline demand cost savings by reducing the amount of annual pipeline capacity required to meet peak-day gas requirements. PSE has been in the process of expanding the storage capacity at Jackson Prairie since March 2003, and plans to continue through 2008. At the end of this project, PSE will have added approximately 2,000,000 Dth of additional working storage capacity. In order to meet the growing peaking requirements in the region, PSE and other owners of Jackson Prairie obtained FERC authorization on February 5, 2007 to increase deliverability of the project from 884,000 Dth per day to 1,196,000 Dth per day. PSE's share of this expansion, 104,000 Dth per day, is expected to cost $15.0 million and to be in-service by November 2008. The Clay Basin storage facility is a supply area storage facility that is used primarily to reduce portfolio costs through injections and withdrawals that take advantage of market price volatility and is also used for system reliability. PSE holds 13,400,000 Dth of Clay Basin capacity under two long-term contracts with remaining terms of 6 years and 13 years. PSE has exchanged 2,000,000 Dth of this Clay Basin capacity for 2,000,000 Dth of AECO storage capacity, which includes withdrawal capacity of 16,700 Dth per day and terminates March 31, 2008. After this exchange, PSE's maximum firm withdrawal capacity and total storage capacity at Clay Basin is over 76,000 Dth per day and exceeds 11,000,000 Dth, respectively.

LNG AND PROPANE-AIR RESOURCES

LNG and propane-air resources provide gas supply on short notice for short periods of time. Due to their typically high cost and slow cycle times, these resources are normally utilized as the supply of last resort in extreme peak-demand periods, typically lasting a few hours or days. PSE has a long-term contract for storage of 241,700 Dth of PSE-owned gas as LNG at NWP's Plymouth facility, which is approximately three and one-half day's supply at a maximum daily deliverability of 70,500 Dth. PSE owns storage capacity for approximately 1.5 million gallons of propane. The propane-air injection facilities are capable of delivering the equivalent of 10,000 Dth of gas per day for up to twelve days directly into PSE's distribution system.

In 2004, a 6,000 Dth capacity LNG storage facility was completed in Gig Harbor. In 2006, PSE expanded the capacity to 10,600 Dth. The purpose of the facility is to provide a supplemental supply of natural gas during periods of high demand, improve overall system reliability and eliminate the need for portable LNG operations in the Gig Harbor area.

GAS TRANSPORTATION CAPACITY

PSE currently holds firm transportation capacity on pipelines owned by NWP, Gas Transmission Northwest (a TransCanada company, "GTN"), TransCanada Pipelines, Ltd. (TransCanada) and Westcoast. Accordingly, PSE pays fixed monthly demand charges for the right, but not the obligation, to transport specified quantities of gas from receipt points to delivery points on such pipelines each day for the term or terms of the applicable agreements.

PSE and WNG CAP I, a wholly-owned subsidiary of PSE, hold firm year-round capacity on NWP through various contracts. PSE and WNG CAP I participate in the secondary pipeline capacity market to achieve savings for PSE's customers. PSE and WNG CAP I hold approximately 520,000 Dth per day of capacity on NWP that provides firm delivery to PSE's service territory. In addition, PSE holds approximately 413,000 Dth per day of seasonal firm capacity on NWP to provide for delivery of gas stored in Jackson Prairie and the Plymouth LNG facility during the heating season. PSE has firm transportation capacity on NWP that supplies the Frederickson 1 generating facility with approximately 22,000 Dth per day, with a remaining term of 12 years. PSE has released certain segments of its firm capacity with third parties to effectively lower transportation costs. PSE's firm transportation capacity contracts with NWP have remaining terms ranging from 1 year to 10 years. However, PSE has either the unilateral right to extend the contracts under their current terms or the right of first refusal to extend such contracts under current FERC orders. PSE's firm transportation capacity on GTN's pipeline, totaling approximately 90,000 Dth per day, has a remaining term of 17 years.

PSE's firm transportation capacity on Westcoast's pipeline is approximately 97,000 Dth per day until October 31, 2012, then approximately 86,000 Dth per day until October 31, 2014, then approximately 41,000 Dth per day until October 31, 2017 and thereafter approximately 15,000 Dth per day until October 31, 2018. PSE has other firm transportation capacity on Westcoast's pipeline, which supplies the Frederickson 1 generating facility, totaling approximately 22,000 Dth per day, with a remaining term of 8 years. PSE has firm capacity on TransCanada's Alberta and British Columbia transportation systems, totaling approximately 80,000 Dth per day. PSE has annual rollover rights for this capacity. In addition, PSE has firm transportation capacity on TransCanada's pipelines commencing in 2008 with a term of 15 years, totaling approximately 8,000 Dth per day.

CAPACITY RELEASE

FERC provided a capacity release mechanism as the means for holders of firm pipeline and storage entitlements to temporarily or permanently relinquish unutilized capacity to others in order to recoup all or a portion of the cost of such capacity. Capacity may be released through several methods including open bidding and by pre-arrangement. PSE continues to successfully mitigate a portion of the demand charges related to both storage and pipeline capacity not utilized during off-peak periods through capacity release. PSE also utilizes capacity release mechanisms to acquire additional assets to serve its growing service territory. WNG CAP I, a PSE subsidiary, provides additional flexibility and benefits from capacity release transactions. Capacity release benefits are passed on to customers through the PGA mechanism.

ENERGY EFFICIENCY

PSE offers programs designed to help new and existing residential, commercial and industrial customers use energy efficiently. PSE uses a variety of mechanisms including cost-effective financial incentives, information and technical services to enable customers to make energy-efficient choices with respect to building design, equipment and building systems, appliance purchases and operating practices. Energy efficiency programs reduce customer consumption of energy thus reducing energy margins. The impact of load reductions is adjusted in rates at each general rate case.

PSE's two-year savings goals are set based on the Integrated Resource Plan and in conjunction with the Conservation Resource Advisory Group per the terms of the 2002 Conservation Stipulation Agreement. For 2004-2005, the minimum savings goals for the two-year period to avoid a "penalty" mechanism were set at 23.2 average MW and 3.5 million therms while the "stretch" goals were set at 39.2 average MW and 5 million therms. PSE achieved 39.34 average MW and 6 million therms of cost-effective energy savings during the two-year timeframe, exceeding its goals.

For 2006-2007, the sum of the annual savings goals for the two-year period is set at 33 average MW and 3.4 million therms. If conservation savings are less than 75.0% of the minimum goal, PSE will be subject to a penalty of $0.8 million. If savings are between 75.0% and 89.0% of the minimum, the penalty is $0.5 million, and between 90.0% and 99.0% of the minimum, the penalty is $0.2 million. Actual results through December 31, 2006 for the 2006-2007 period are 18.98 average MWs and 2.4 million therms.

Since May 1997, PSE has recovered electric energy efficiency (or conservation) expenditures through a tariff rider mechanism. The mechanism allows PSE to defer the efficiency expenditures and amortize them to expense as PSE concurrently collects the efficiency expenditures in rates over a one-year period. As a result of the rider, electric energy efficiency expenditures have no effect on earnings.

Since 1995, PSE has been authorized by the Washington Commission to defer gas energy efficiency (or conservation) expenditures and recover them through a tariff tracker mechanism. The tracker allows PSE to defer efficiency expenditures and recover them in rates over the subsequent year. The tracker also allows PSE to recover an allowance for funds used to conserve energy on any outstanding balance that is not being recovered in rates. As a result of the tracker mechanism, gas energy efficiency expenditures have no impact on earnings.

ENVIRONMENT

The Company's operations are subject to environmental laws and regulation by federal, state and local authorities. Due to the inherent uncertainties surrounding the development of federal and state environmental and energy laws and regulations, the Company cannot determine the impact such laws may have on its existing and future facilities.

GREENHOUSE GAS POLICY

PSE recognizes the growing concern that increased atmospheric concentrations of greenhouse gases contribute to climate change. PSE believes that climate change is a very important issue that requires careful analysis and responses. PSE's policy is to take cost-effective measures to mitigate and/or offset greenhouse gas emissions from our energy activities while maintaining a dependable, cost-effective and diverse energy portfolio mix that will sustain our customers' needs now and into the future. PSE is taking and will continue to take appropriate steps to meet the goal of providing cost-effective and reliable energy while decreasing the impact on climate change through the implementation of these measures. The full PSE Greenhouse Gas Policy is available at www.pse.com.

REGULATION OF EMISSIONS

PSE facilities are subject to regulation of emissions, including PSE's interest in coal-fired, steam-electric generating plants at Colstrip, Montana and its combustion turbine units. There is no assurance that future environmental laws and regulations affecting sulfur dioxide, carbon monoxide particulate matter or nitrogen oxide emissions will not be more restrictive, or that restrictions on greenhouse gas emissions, such as carbon dioxide, or other combustion byproducts, such as mercury, may not be imposed at the federal or state level.

EMISSIONS INVENTORY

During 2006, PSE's total electric retail load of 21,099,045 MWh was served from a supply portfolio of owned and purchased resources. Since 2002, PSE has voluntarily undertaken an inventory of its greenhouse gas (GHG) emissions associated with this portfolio. Such inventory follows the protocol established by the World Resource Institute GHG Protocol (GHG Protocol). The most recent data indicate that PSE's total GHG emissions (direct and indirect) from its electric supply portfolio in 2005 were 12,999,051 tons (CO2e). Approximately 54.3% of these emissions (approximately 7,058,313 tons) are associated with PSE's ownership and contractual interests in the 2,200 MW Colstrip, Montana coal-fired steam electric generation facility (the "Facility").

Colstrip is a significant part of the diversified portfolio PSE owns and/or operates for its customers. Consequently, while Colstrip remains a significant portion of our overall GHG emissions, PSE's overall emissions strategy demonstrates a concerted effort to manage our customers' needs with an appropriate balance of new renewable generation, existing generation owned and/or operated by PSE, and significant energy efficiency efforts.

With ongoing development of state and federal initiatives intended to address climate change, the challenge to develop strategic solutions is more complicated than ever. However, PSE believes that now is the time to act. Consequently it is PSE's intent to incorporate into the IRP a long-term strategic goal that will adhere to the objectives of our recently published Greenhouse Gas Policy.

On May 18, 2005, the Environmental Protection Agency (EPA) enacted the Clean Air Mercury Rule (CAMR) that will permanently cap and reduce mercury emissions from coal-fired power plants. The Montana Board of Environmental Review approved a more stringent rule to limit mercury emissions from coal-fired plants on October 16, 2006 (0.9 lbs/TBtu, instead of the federal 1.4 lbs/TBtu). 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. Preliminary treatment technology studies undertaken by the Colstrip owners estimate that PSE's portion of the costs to comply with the new rule could be as much as $75.0 million in construction expenditures; this number could change as new information becomes available.

In December 2003, the EPA issued an Administrative Consent Order (ACO) which alleged violation of the Clean Air Act permit requirement to submit, for review and approval by the EPA, an analysis and proposal for reducing emissions of nitrogen oxide to address visibility concerns upon the occurrence of certain triggering events which EPA asserts occurred in 1980. Although Colstrip owners believe that the ACO is unfounded, the Colstrip owners signed a settlement agreement in December 2006 that is now awaiting signature by EPA, and then will be entered by the court. The agreement includes installation of low nitrogen oxide equipment installation on Colstrip Units 3 & 4 which will cost PSE approximately $2.65 million.

FEDERAL ENDANGERED SPECIES ACT

Since 1991, a total of thirteen species of salmon and steelhead have been listed as threatened or endangered species under the Endangered Species Act, which influences hydroelectric operations. While the most significant impacts have affected the Mid-Columbia PUDs, certain ESA impacts may affect PSE operations, potentially representing cost exposure and operational constraints. PSE is actively engaging the federal agencies to address Endangered Species Act issues for PSE's generating facilities.

EXECUTIVE OFFICERS OF THE REGISTRANTS

The executive officers of Puget Energy as of December 31, 2006 are listed below. For their business experience during the past five years, please refer to the table below regarding Puget Sound Energy's executive officers. Officers of Puget Energy are elected for one-year terms.

NAME	AGE	OFFICES
S. P. Reynolds	58	Chairman, President and Chief Executive Officer since May 2005; President and Chief Executive Officer, 2002 – 2005. Director since January 2002.
J. W. Eldredge	56	Vice President, Corporate Secretary and Chief Accounting Officer since May 2005; Corporate Secretary and Chief Accounting Officer 1999 – 2005.
D. E. Gaines	49	Vice President Finance and Treasurer since March 2002.
J. L. O'Connor	50	Senior Vice President General Counsel, Chief Ethics and Compliance Officer since October 2005; Vice President and General Counsel, 2003 - 2005.
B. A. Valdman	43	Senior Vice President Finance and Chief Financial Officer since January 2004.

The executive officers of Puget Sound Energy as of December 31, 2006 are listed below along with their business experience during the past five years. Officers of Puget Sound Energy are elected for one-year terms.

NAME	AGE	OFFICES
S. P. Reynolds	58	Chairman, President and Chief Executive Officer since May 2005; Director since January 2002; President and Chief Executive Officer 2002 – 2005; President and Chief Executive Officer of Reynolds Energy International, 1998 – 2002.
D. P. Brady	42	Senior Vice President Customer Service, Information Technology and Chief Information Officer since October 2005; Vice President Customer Services 2003 – 2005; Director and Assistant to Chief Operating Officer, 2002 – 2003. Prior to joining PSE, he was Managing Director of Irvine Associates Merchant Banking Group, 2001 – 2002.
P. K. Bussey	50	Senior Vice President Corporate Affairs since October 2005; Vice President Regional and Public Affairs, 2003 – 2005. Prior to joining PSE, he was President of the Washington Round Table, 1996 – 2003.
J. W. Eldredge	56	Vice President, Corporate Secretary, Controller and Chief Accounting Officer since May 2001.
D. E. Gaines	49	Vice President Finance and Treasurer since March 2002; Vice President and Treasurer, 2001 – 2002.
K. J. Harris	42	Senior Vice President Regulatory Policy and Energy Efficiency since October 2005; Vice President Regulatory and Government Affairs, 2003 – 2005; Vice President Regulatory Affairs, 2002 – 2003; Director Load Resource Strategies and Associate General Counsel, 2001 – 2002.
E. M. Markell	55	Senior Vice President Energy Resources since February 2003; Vice President Corporate Development, 2002 – 2003. Prior to joining PSE, he was Chief Financial Officer, Club One, Inc., 2000 – 2002.
S. McLain	50	Senior Vice President Operations since February 2003; Vice President Operations – Delivery, 1999 – 2003.
M. D. Mellies	46	Vice President Human Resources since October 2005. Prior to joining PSE, she was General Manager of Human Resources at Microsoft, 2002 – 2005.
J. L. O'Connor	50	Senior Vice President General Counsel, Chief Ethics and Compliance Officer since October 2005; Vice President and General Counsel, 2003 – 2005. Prior to joining PSE, she was interim General Counsel, Starbucks Corporation, 2002; Senior Vice President and Deputy General Counsel, Starbucks Corporation, 2001 – 2002.
C. E. Shirley	53	Vice President Energy Efficiency Services since October 2005; Director Energy Efficiency Services, 2002 – 2005. Prior to joining PSE, he was Senior Manager of Energy Services for Snohomish County Public Utility District, 1995 – 2002.
B. A. Valdman	43	Senior Vice President Finance and Chief Financial Officer since December 2003. Prior to joining PSE, he was Managing Director with JP Morgan Securities, Inc., 2000 – 2003.

P. M. Wiegand	54	Vice President Project Development and Contract Management since July 2003; Vice President Corporate Planning, 2003; Vice President Corporate Planning and Performance, 2002 – 2003; Vice President Risk Management and Strategic Planning, 2000 – 2002.

ITEM 1A. RISK FACTORS

The following risk factors, in addition to other factors and matters discussed elsewhere in this report, should be carefully considered. The risks and uncertainties described below are not the only risks and uncertainties that Puget Energy and PSE may face. Additional risks and uncertainties not presently known or currently deemed immaterial also may impair PSE's business operations. If any of the following risks actually occur, Puget Energy's and PSE's business, results of operations and financial conditions would suffer.

RISKS RELATING TO THE UTILITY BUSINESS

THE ACTIONS OF REGULATORS CAN SIGNIFICANTLY AFFECT PSE'S EARNINGS, LIQUIDITY AND BUSINESS ACTIVITIES.

The rates that PSE is allowed to charge for its services is the single most important item influencing its financial position, results of operations and liquidity. PSE is highly regulated and the rates that it charges its customers are determined by the Washington Commission.

PSE is also subject to the regulatory authority of the Washington Commission with respect to accounting, the issuance of securities and certain other matters, and the regulatory authority of FERC with respect to the transmission of electric energy, the resale of electric energy at wholesale, accounting and certain other matters. Policies and regulatory actions by these regulators could have a material impact on PSE's financial position, results of operations and liquidity.

PSE'S RECOVERY OF COSTS IS SUBJECT TO REGULATORY REVIEW AND ITS OPERATING INCOME MAY BE ADVERSELY AFFECTED IF ITS COSTS ARE DISALLOWED OR RECOVERY IS DELAYED.

The Washington Commission determines the rates PSE may charge to its retail customers based on a normalized cost of producing power. If in a specific year PSE's costs are higher than normal, rates will not be sufficient to permit PSE to earn the allowed return or to cover its costs and recovery of energy costs will be deferred until subsequent ratemaking proceedings. In addition, the Washington Commission decides what level of expense and investment is reasonable and prudent in providing service. If the Washington Commission decides that part of PSE's costs do not meet the standard, those costs may be disallowed partially or entirely and not recovered in rates. For these reasons, the rates authorized by the Washington Commission may not be sufficient to earn the allowed return or recover the costs incurred by PSE in a given period.

THE PCA MECHANISM BY WHICH VARIATIONS IN PSE'S POWER COSTS ARE APPORTIONED BETWEEN IT AND ITS CUSTOMERS COULD EXPERIENCE SIGNIFICANT INCREASE IN EXPENSES.

PSE has a PCA mechanism that provides for recovery of power costs from customers or refunding of power cost savings to customers, as those costs vary from the "power cost baseline" level of power costs which are set in part based on normalized assumptions about weather and hydro conditions. Excess power costs or power cost savings will be apportioned between PSE and its customers pursuant to the graduated scale set forth in the PCA mechanism without operation of any cap.

PSE MAY BE UNABLE TO ACQUIRE ENERGY SUPPLY RESOURCES TO MEET PROJECTED CUSTOMER NEEDS OR MAY FAIL TO SUCCESSFULLY INTEGRATE SUCH ACQUISITIONS.

PSE projects that future energy needs will exceed current purchased and Company-controlled power resources. As part of PSE's business strategy, it plans to acquire additional electric generation and delivery infrastructure to meet customer needs. If PSE cannot acquire further additional energy supply resources at a reasonable cost, it may be required to purchase additional power in the open market at a cost that could significantly increase its expenses and reduce earnings and cash flows. Additionally, PSE may not be able to timely recover some or all of those increased expenses through ratemaking.

While PSE expects to identify the benefits of new energy supply resources prior to their acquisition and integration, it may not be able to achieve the expected benefits of such energy supply sources.

THE COMPANY'S CASH FLOW AND EARNINGS COULD BE ADVERSELY AFFECTED BY POTENTIAL HIGH PRICES AND VOLATILE MARKETS FOR PURCHASED POWER, INCREASED CUSTOMER DEMAND FOR ENERGY, RECURRENCE OF LOW

AVAILABILITY OF HYDROELECTRIC RESOURCES, OUTAGES OF ITS GENERATING FACILITIES OR A FAILURE TO DELIVER ON THE PART OF ITS SUPPLIERS.

The utility business involves many operating risks. If PSE's operating expenses, including the cost of purchased power and natural gas, significantly exceed the levels recovered from retail customers for an extended period of time, its cash flow and earnings would be negatively affected. Factors which could cause purchased power and gas costs to be higher than anticipated include, but are not limited to, high prices in western wholesale markets during periods when PSE has insufficient energy resources to meet its load requirements and/or high volumes of energy purchased in wholesale markets at prices above the amount recovered in retail rates due to:

- Increases in demand due, for example, either to weather or customer growth;
- Below normal energy generated by PSE-owned hydroelectric resources due to low streamflow conditions;
- Extended outages of any of PSE-owned generating facilities or the transmission lines that deliver energy to load centers;
- Failure to perform on the part of any party from which PSE purchases capacity or energy; and
- The effects of large-scale natural disasters, such as the hurricanes recently experienced in the southern United States.

PSE'S ELECTRIC GENERATING FACILITIES ARE SUBJECT TO OPERATIONAL RISKS THAT COULD RESULT IN UNSCHEDULED PLANT OUTAGES, UNANTICIPATED OPERATION AND MAINTENANCE EXPENSES AND INCREASED POWER PURCHASE COSTS.

PSE owns and operates coal, gas-fired, hydro, wind-powered and oil-fired generating facilities. Operation of electric generating facilities involves risks that can adversely affect energy output and efficiency levels. Included among these risks are:

- Increased prices for fuel and fuel transportation as existing contracts expire;
- Facility shutdowns due to a breakdown or failure of equipment or processes or interruptions in fuel supply;
- Disruptions in the delivery of fuel and lack of adequate inventories;
- Labor disputes;
- Inability to comply with regulatory or permit requirements;
- Disruptions in the delivery of electricity;
- Operator error;
- Terrorist attacks; and
- Catastrophic events such as fires, explosions, floods or other similar occurrences.

PSE IS SUBJECT TO THE COMMODITY PRICE, DELIVERY AND CREDIT RISKS ASSOCIATED WITH THE ENERGY MARKETS.

In connection with matching loads and resources, PSE engages in wholesale sales and purchases of electric capacity and energy, and, accordingly, is subject to commodity price risk, delivery risk, credit risk and other risks associated with these activities. Credit risk includes the risk that counterparties owing PSE money or energy will breach their obligations. Should the counterparties to these arrangements fail to perform, PSE may be forced to enter into alternative arrangements. In that event, PSE's financial results could be adversely affected. Although PSE's models take into account the expected probability of default by counterparties, actual exposure to a default by a particular counterparty could be greater than the models predict.

To lower its financial exposure related to commodity price fluctuations, PSE may use forward delivery agreements, swaps and option contracts to hedge commodity price risk with a diverse group of counterparties. However, PSE does not always cover the entire exposure of its assets or positions to market price volatility and the coverage will vary over time. To the extent PSE has unhedged positions or its hedging procedures do not work as planned, fluctuating commodity prices could adversely impact its results of operations.

CONDITIONS THAT MAY BE IMPOSED IN CONNECTION WITH HYDROELECTRIC LICENSE RENEWALS MAY REQUIRE LARGE CAPITAL EXPENDITURES AND REDUCE EARNINGS AND CASH FLOWS.

PSE is in the process of renewing the federal licenses for its Baker River hydroelectric project and implementing the federal licensing requirements for the Snoqualmie Falls hydroelectric project. The relicensing process is a political and public regulatory process that involves sensitive resource issues. PSE cannot predict with certainty the conditions that may be imposed during the relicensing process, the economic impact of those requirements, whether new licenses will ultimately be issued, modified, or whether PSE will be willing to meet the relicensing requirements to continue operating these hydroelectric projects.

COSTS OF COMPLIANCE WITH ENVIRONMENTAL AND ENDANGERED SPECIES LAWS ARE SIGNIFICANT AND THE COST OF COMPLIANCE WITH NEW ENVIRONMENTAL OR ENDANGERED SPECIES LAWS AND THE INCURRENCE OF ENVIRONMENTAL LIABILITIES COULD ADVERSELY AFFECT PSE'S RESULTS OF OPERATIONS.

PSE's operations are subject to extensive federal, state and local regulation relating to environmental and endangered species protection. To comply with these legal requirements, PSE must spend significant sums on environmental and endangered species monitoring, pollution control equipment and emission fees. New environmental and endangered species laws and regulations affecting PSE's operations may be adopted, and new interpretations of existing laws and regulations could be adopted or become applicable to PSE or its facilities, which may substantially increase environmental and endangered species expenditures made by it in the future. Compliance with these or other future regulations could require significant capital expenditures by PSE and adversely affect PSE's financial position, results of operations, cash flows and liquidity. In addition, PSE may not be able to recover all of its costs for environmental expenditures through electric and natural gas rates at current levels in the future.

With respect to endangered species laws, the listing or proposed listing of several species of salmon in the Pacific Northwest is causing a number of changes to the operations of hydroelectric generating facilities on Pacific Northwest rivers, including the Columbia River. These changes could reduce the amount, and increase the cost, of power generated by hydroelectric plants owned by PSE or in which PSE has an interest and increase the cost of the permitting process for these facilities.

Under current law, PSE is also generally responsible for any on-site liabilities associated with the environmental condition of the facilities that it currently owns or operates or has previously owned or operated, regardless of whether the liabilities arose before, during or after the time the facility was owned or operated. The incurrence of a material environmental liability or the new regulations governing such liability could result in substantial future costs and have a material adverse effect on PSE's results of operations and financial condition.

THE COMPANY'S BUSINESS IS DEPENDENT ON ITS ABILITY TO SUCCESSFULLY ACCESS CAPITAL MARKETS.

The Company relies on access to both short-term money markets as a source of liquidity and longer-term capital markets to fund its utility construction program and other capital expenditure requirements not satisfied by cash flow from its operations. If the Company is unable to access capital at competitive rates, its ability to pursue improvements or acquisitions, including generating capacity, which may be relied on for future growth and to otherwise implement its strategy, could be adversely affected.

Certain market disruptions or a downgrade of the Company's credit rating may increase the Company's cost of borrowing or adversely affect the ability to access one or more financial markets.

A DOWNGRADE IN THE COMPANY'S CREDIT RATING COULD NEGATIVELY AFFECT ITS ABILITY TO ACCESS CAPITAL AND THE ABILITY TO HEDGE IN WHOLESALE MARKETS.

Standard and Poor's and Moody's Investor Services rate PSE's senior secured debt at "BBB" with a stable outlook and "Baa2" with a stable outlook, respectively. Although the Company is not aware of any current plans of S&P or Moody's to lower their respective ratings on PSE's debt, the Company cannot be assured that such credit ratings will not be downgraded.

Although neither Puget Energy nor PSE has any rating downgrade provisions in its credit facilities that would accelerate the maturity dates of outstanding debt, a downgrade in the Companies' credit ratings could adversely affect their 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 spreads over the index and commitment fee increase as PSE's corporate credit ratings decline. A downgrade in commercial paper ratings could preclude PSE's ability to issue commercial paper under its current programs.

Any downgrade below investment grade of PSE's senior secured debt could allow counterparties 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, all of which would expose PSE to additional costs.

THE COMPANY'S OPERATING RESULTS FLUCTUATE ON A SEASONAL AND QUARTERLY BASIS.

PSE's business is seasonal and weather patterns can have a material impact on its operating performance. Because natural gas is heavily used for residential and commercial heating, demand depends heavily on weather patterns in PSE's service territory, and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. However, the recent increase in the price of natural gas may result in decreased customer demand, despite normal or lower than normal temperatures. Demand for electricity is also greater in the winter months associated with heating. Accordingly, PSE's operations have historically generated less revenues and income when weather conditions are milder in the winter. In the event that the Company experiences unusually mild winters, results of operations and financial condition could be adversely affected.

THE COMPANY MAY BE ADVERSELY AFFECTED BY LEGAL PROCEEDINGS ARISING OUT OF THE ELECTRICITY SUPPLY SITUATION IN THE WESTERN POWER MARKETS, WHICH COULD RESULT IN REFUNDS OR OTHER LIABILITIES.

The Company is involved in a number of legal proceedings and complaints with respect to power markets in the western United States. Most of these proceedings relate to the significant increase in the spot market price of energy in western power markets in 2000 and 2001, which allegedly contributed to or caused unjust and unreasonable prices and allegedly may have been the result of manipulations by certain other parties. These proceedings include, but are not limited to, refund proceedings and hearings in California and the Pacific Northwest and complaints and cross-complaints filed by various parties with respect to alleged misconduct by other parties in western power markets. 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, individually or in the aggregate, will not materially and adversely affect PSE's financial condition, results of operations or liquidity.

THE COMPANY MAY BE NEGATIVELY AFFECTED BY ITS INABILITY TO ATTRACT AND RETAIN PROFESSIONAL AND TECHNICAL EMPLOYEES.

The Company's ability to implement a workforce succession plan is dependent upon the Company's ability to employ and retain skilled professional and technical workers in an aging workforce. Without a skilled workforce, the Company's ability to provide quality service to PSE's customers and meet regulatory requirements will be challenged and could affect earnings.

THE COMPANY MAY BE ADVERSELY AFFECTED BY EXTREME EVENTS IN WHICH THE COMPANY IS NOT ABLE TO PROMPTLY RESPOND AND REPAIR THE ELECTRIC AND GAS INFRASTRUCTURE SYSTEM.

The Company must maintain an emergency planning and training program to allow the Company to quickly respond to extreme events. Without emergency planning, the Company is subject to availability of outside contractors during an extreme event which may impact the quality of service provided to PSE's customers. In addition, a slow response to extreme events may have an adverse affect on earnings as customers may be without electricity and gas for an extended period of time.

THE COMPANY MAY BE NEGATIVELY AFFECTED BY UNFAVORABLE CHANGES IN THE TAX LAWS OR THEIR INTERPRETATION.

Changes in tax law, related regulations, or differing interpretation or enforcement of applicable law by the Internal Revenue Service or other taxing jurisdiction could have a material adverse impact on the Company's financial statements. The tax law, related regulations and case law are inherently complex. The Company must make judgments and interpretations about the application of the law when determining the provision for taxes. Disputes over interpretations of tax laws may be settled with the taxing authority upon examination or audit. The Company's tax obligations include income, real estate, sales and use, business and occupation and employment-related taxes and ongoing appeals issues related to these taxes. These judgments may include reserves for potential adverse outcomes regarding tax positions that have been taken that may be subject to challenge by the taxing authorities.

RISKS RELATING TO PUGET ENERGY'S CORPORATE STRUCTURE

AS A HOLDING COMPANY, PUGET ENERGY IS SUBJECT TO RESTRICTIONS ON ITS ABILITY TO PAY DIVIDENDS.

As a holding company with no significant operations of its own, the primary source of funds for the payment of dividends to its shareholders is dividends PSE pays to Puget Energy. PSE is a separate and distinct legal entity and has no obligation to pay any amounts to Puget Energy, whether by dividends, loans or other payments. The ability of PSE to pay dividends or make distributions to Puget Energy, and accordingly, Puget Energy's ability to pay dividends on its common stock, will depend on its earnings, capital requirements and general financial condition. If Puget Energy does not receive adequate distributions from PSE, it may not be able to make or may have to reduce dividend payments on its common stock.

PSE's payment of common stock dividends to Puget Energy is restricted by provisions of covenants applicable to its preferred stock and long-term debt contained in its restated articles of incorporation and electric and gas mortgage indentures. Puget Energy's Board of Directors reviews the dividend policy periodically in light of the factors referred to above and cannot assure shareholders of the amount of dividends, if any, that may be paid in the future.

FUTURE SALES OF PUGET ENERGY'S COMMON STOCK ON THE PUBLIC MARKET COULD LOWER THE STOCK PRICE.

Puget Energy may sell additional shares of common stock in public offerings, through the stock purchase and dividend reinvestment plan or through common stock offering programs which it has entered into with two financial institutions. Puget Energy cannot predict the size of future issuances of common stock, or the effect, if any, that future issuances and sales of shares of common stock will have on the market price of common stock. Sales of substantial amounts of common stock, or the perception that such sales could occur, may adversely affect the prevailing market price of common stock.

THE MARKET PRICE FOR COMMON STOCK IS UNCERTAIN AND MAY FLUCTUATE SIGNIFICANTLY.

Puget Energy cannot predict whether the market price of its common stock will rise or fall. Numerous factors influence the trading price of its common stock. These factors may include changes in financial condition, results of operations and prospects, legal and administrative proceedings and political, economic, financial and other factors that can affect the capital markets generally, the stock exchanges on which Puget Energy's common stock is traded and its business segments.

CERTAIN PROVISIONS OF LAW, AS WELL AS PROVISIONS IN THE RESTATED ARTICLES OF INCORPORATION, BYLAWS AND SHAREHOLDERS RIGHTS PLAN, MAY MAKE IT MORE DIFFICULT FOR OTHERS TO OBTAIN CONTROL OF PUGET ENERGY.

Puget Energy is a Washington corporation and certain anti-takeover provisions of Washington laws apply and create various impediments to the acquisition of control of Puget Energy or to the consummation of certain business combinations. In addition, Puget Energy's restated articles of incorporation, bylaws and shareholders rights plan contain provisions which may make it more difficult to remove incumbent directors or effect certain business combinations with Puget Energy without the approval of the Board of Directors. These provisions of law and of Puget Energy's corporate documents, individually or in the aggregate, could discourage a future takeover attempt which individual shareholders might deem to be in their best interests or in which shareholders would receive a premium for their shares over current prices.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

The principal electric generating plants and underground gas storage facilities owned by PSE are described under Item 1, Business - Electric Supply and Gas Supply. PSE owns its transmission and distribution facilities and various other properties. Substantially all properties of PSE are subject to the liens of PSE's mortgage indentures. PSE's corporate headquarters is housed in a leased building located in Bellevue, Washington.

ITEM 3. LEGAL PROCEEDINGS

See the section under Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations-Proceedings Relating to the Western Power Market.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED SHAREHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Puget Energy's common stock, the only class of common equity of Puget Energy, is traded on the New York Stock Exchange under the symbol "PSD." At February 21, 2007, there were approximately 36,800 holders of record of Puget Energy's common stock. The outstanding shares of PSE's common stock, the only class of common equity of PSE, are held by Puget Energy and are not traded.

The following table shows the market price range of, and dividends paid on, Puget Energy's common stock during the periods indicated in 2006 and 2005. Puget Energy and its predecessor companies have paid dividends on common stock each year since 1943 when such stock first became publicly held.

	2006			2005		
	Price Range		Dividends	Price Range		Dividends
Quarter Ended	High	Low	Paid	High	Low	Paid
March 31	$21.68	$20.26	$0.25	$24.60	$21.30	$0.25
June 30	21.62	20.13	0.25	23.56	20.73	0.25
September 30	22.86	21.20	0.25	24.36	22.05	0.25
December 31	25.91	22.72	0.25	23.70	20.21	0.25

The amount and payment of future dividends will depend on Puget Energy's financial condition, results of operations, capital requirements and other factors deemed relevant by Puget Energy's Board of Directors. The Board of Directors' current policy is to pay out approximately 60.0% of normalized utility earnings in dividends.

Puget Energy's primary source of funds for the payment of dividends to its shareholders is dividends received from PSE. PSE's payment of common stock dividends to Puget Energy is restricted by provisions of certain covenants applicable to preferred stock and long-term debt contained in PSE's Restated Articles of Incorporation and electric and gas mortgage indentures. Under the most restrictive covenants of PSE, earnings reinvested in the business unrestricted as to payment of cash dividends were approximately $398.9 million at December 31, 2006.

ITEM 6. SELECTED FINANCIAL DATA

The following tables show selected financial data.

PUGET ENERGY
SUMMARY OF OPERATIONS
(DOLLARS IN THOUSANDS, EXCEPT PER SHARE DATA)

Years Ended December 31	2006	2005	2004	2003 [1]	2002
Operating revenue [2]	$ 2,905,693	$ 2,573,210	$ 2,198,877	$ 2,041,016	$ 1,995,652
Operating income	326,616	303,163	287,678	297,723	294,074
Net income from continuing operations	167,224	146,283	125,410	114,600	100,597
Net income	219,216	155,726	55,022	116,197	110,052
Basic earnings per common share from continuing operations	1.44	1.43	1.26	1.21	1.13
Basic earnings per common share	1.89	1.52	0.55	1.23	1.24
Diluted earnings per common share from continuing operations	1.44	1.42	1.26	1.20	1.13
Diluted earnings per common share	1.88	1.51	0.55	1.22	1.24
Dividends per common share	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.21
Book value per common share	18.29	17.52	16.24	16.71	16.27
Total assets at year end	$ 7,066,039	$ 6,609,951	$ 5,851,219	$ 5,708,724	$ 5,772,132
Long-term debt	2,608,360	2,183,360	2,069,360	1,955,347	2,021,832
Preferred stock subject to mandatory redemption	1,889	1,889	1,889	1,889	43,162
Corporation obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely junior subordinated debentures of the corporation	--	--	--	--	300,000
Junior subordinated debentures of the corporation payable to a subsidiary trust holding mandatorily redeemable preferred securities	37,750	237,750	280,250	280,250	--

1 *In 2003, FASB issued Interpretation No. 46 (FIN 46) which required the consolidation of PSE's 1995 Conservation Trust Transaction. As a result, revenues and expenses increased $5.7 million with no effect on net income, and assets and liabilities increased $4.2 million in 2003. FIN 46 also required deconsolidation of PSE's trust preferred securities that are now classified as junior subordinated debt. This deconsolidation has no impact on assets, liabilities, receivables or earnings for 2003.*

2 *Operating Electric Revenues and Purchased Electricity expenses in 2003 and 2002 were revised as a result of implementing Emerging Issues Task Force Issue No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB No. 133 and Not 'Held for Trading Purposes' as Defined in Issue No. 02-03" (EITF No. 03-11), which became effective on January 1, 2004. Operating Electric Revenues and Purchased Electricity expense for Puget Energy and Puget Sound Energy were reduced by $108.7 million and $77.1 million in 2003 and 2002, respectively, with no effect on net income.*

PUGET SOUND ENERGY
SUMMARY OF OPERATIONS
(DOLLARS IN THOUSANDS)

YEARS ENDED DECEMBER 31	2006	2005	2004	2003[1]	2002
Operating revenue [2]	$ 2,905,693	$ 2,573,210	$ 2,198,877	$ 2,041,016	$ 1,995,652
Operating income	327,490	303,496	288,241	297,904	294,593
Net income for common stock	176,740	146,769	126,192	114,735	101,117
Total assets at year end	$ 7,061,413	$ 6,339,800	$ 5,579,756	$ 5,359,104	$ 5,453,390
Long-term debt	2,608,360	2,183,360	2,064,360	1,950,347	2,021,832
Preferred stock subject to mandatory redemption	1,889	1,889	1,889	1,889	43,162
Corporation obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely junior subordinated debentures of the corporation	--	--	--	--	300,000
Junior subordinated debentures of the corporation payable to a subsidiary trust holding mandatorily redeemable preferred securities	37,750	237,750	280,250	280,250	--

1 *See note 1 above.*

2 *See note 2 above.*

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with the financial statements and related notes thereto included elsewhere in this annual report on Form 10-K. The discussion contains forward-looking statements that involve risks and uncertainties, such as Puget Energy's and Puget Sound Energy's (PSE) objectives, expectations and intentions. Words or phrases such as "anticipates," "believes," "estimates," "expects," " plans," "predicts," "projects," "will likely result," "will continue" and similar expressions are intended to identify certain of these 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. Readers are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date of this report. Puget Energy's and PSE's actual results could differ materially from results that may be anticipated by such forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, those discussed in the section entitled "Forward-Looking Statements" included elsewhere in this report. Except as required by law, neither Puget Energy nor PSE undertakes an obligation to revise any forward-looking statements in order to reflect events or circumstances that may subsequently arise. Readers are urged to carefully review and consider the various disclosures made in this report and in Puget Energy's and PSE's other reports filed with the United States Securities and Exchange Commission that attempt to advise interested parties of the risks and factors that may affect Puget Energy's and PSE's business, prospects and results of operations.

OVERVIEW

Puget Energy, Inc. (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. 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. (Tenaska) 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 twelve months ended December 31, 2006. 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 $24.3 million. In addition, Puget Energy established a charitable foundation, Puget Sound Energy 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. PSE's operating revenues and associated expenses are not generated evenly during the year. Variations in energy usage by consumers occur from season to season and from month to month within a season, primarily as a result of weather conditions. PSE normally experiences its highest retail energy sales 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.

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 and significant evolving environmental legislation.

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 2005 and the Wild Horse wind project in December 2006 are two steps in reaching this goal. The Hopkins Ridge wind project provides a rated capacity of 150 megawatts (MW) or 52 average MW. The Wild Horse wind project provides a rated capacity of 229 MW or 73 average MW. These projects are considered to be non-firm energy due to the reliance on wind to produce the energy.

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 IRP 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 IRP was followed by issuing an all-source request for proposal (RFP) on November 1, 2005.

In addition, on February 21, 2007, PSE acquired the Goldendale Generating Station, a 277 MW capacity natural gas generating facility in the state of Washington, from the Calpine Corporation through its bankruptcy proceeding. PSE paid $120.0 million for the generating facility.

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 MW of long-term power supply in total. The outcome of such discussion and negotiation are not known at this time.

NON-GAAP FINANCIAL MEASURES

The following discussion includes financial information prepared in accordance with generally accepted accounting principles (GAAP), as well as two other financial measures, Electric Margin and Gas Margin, that are considered "non-GAAP financial measures." Generally, a non-GAAP financial measure is a numerical measure of a Company's financial performance, financial position or cash flows that exclude (or include) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP. The presentation of Electric Margin and Gas Margin is intended to supplement investors' understanding of the Company's operating performance. Electric Margin and Gas Margin are used by the Company to determine whether the Company is collecting the appropriate amount of energy costs from its customers to allow recovery of operating costs. Our Electric Margin and Gas Margin measures may not be comparable to other companies' Electric Margin and Gas Margin measures. Furthermore, these measures are not intended to replace operating income as determined in accordance with GAAP as an indicator of operating performance.

FINANCIAL CONDITION AND RESULTS OF OPERATIONS

PUGET ENERGY

All the operations of Puget Energy are conducted through its subsidiary PSE. Net income in 2006 was $219.2 million on operating revenues from continuing operations of $2.9 billion compared to $155.7 million on operating revenues from continuing operations of $2.6 billion in 2005 and $55.0 million on operating revenues from continuing operations of $2.2 billion in 2004. Income from continuing operations in 2006 was $167.2 million compared to $146.3 million in 2005 and $125.4 million in 2004.

Basic earnings per share in 2006 was $1.89 on 116.0 million weighted average common shares outstanding compared to $1.52 on 102.6 million weighted average common shares outstanding in 2005 and $0.55 on 99.5 million weighted average common shares outstanding in 2004. Diluted earnings per share in 2006 was $1.88 on 116.5 million weighted average common shares outstanding compared to $1.51 on 103.1 million weighted average common shares outstanding in 2005 and $0.55 on 99.9 million weighted average common shares outstanding in 2004. Included in basic earnings per share for 2006 was $0.45 compared to $0.09 and $(0.71) for 2005 and 2004, respectively, related to discontinued operations. Included in diluted earnings per share for 2006 was $0.45 compared to $0.09 and $(0.71) for 2005 and 2004, respectively, related to discontinued operations.

Income from continuing operations excluding the impact of the charitable contribution to the Puget Sound Energy Foundation was $177.0 million for 2006. 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 $1.52 for the twelve months ended December 31, 2006, excluding the impact of the charitable contribution to the Puget Sound Energy Foundation. A reconciliation to amounts under GAAP is as follows:

(Dollars in millions, except per share amounts)	Twelve Months Ended December 31, 2006
Income from continuing operations, as reported	$ 167.2
Add: Impact of charitable contribution to Foundation, net of tax	9.8
Income from continuing operations, excluding charitable contribution	$ 177.0
Earnings per share:	
Basic and diluted earnings per share before cumulative effect of accounting change from continuing operations, as reported	$ 1.44
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	$ 1.52

Net income in 2006 benefited from income from discontinued operations of InfrastruX of $51.9 million (after-tax) compared to $9.5 million (after-tax) for 2005. Puget Energy's income from discontinued operations for 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. Natural gas and electric margins increased by $22.6 million and $46.0 million, respectively, for 2006 compared to 2005, which positively impacted net income. The increase in natural gas margins resulted from increased natural gas general tariff rates and increased sales volumes. The increase in electric margins was the result of increased sales volumes, overrecovery of power costs under the power cost adjustment (PCA) mechanism and two power cost only rate case (PCORC) rate increases effective November 1, 2005 and July 1, 2006. Net income in 2005 was positively impacted by an increase in income from continuing operations of $20.6 million due to increased electric and gas margins of $73.4 million. This increase was due primarily to a higher Tenaska disallowance in 2004 of $43.4 million compared to $4.1 million in 2005. Increased electricity and gas sales volumes increased margin by $24.5 million as compared to 2004. Gas margin also increased $17.3 million as a result of the 2005 gas general rate case. Offsetting the increases were higher operations and maintenance costs of $42.1 million and depreciation and amortization of $13.0 million. In addition, income from discontinued operations increased $79.9 million in 2005 compared to 2004 primarily due to lower non-cash impairments and favorable industry conditions in the utility construction services sector.

<u>PUGET SOUND ENERGY</u>
<u>2006 COMPARED TO 2005</u>

ENERGY MARGINS

The following table displays the details of electric margin changes from 2005 to 2006. 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) TWELVE MONTHS ENDED DECEMBER 31	ELECTRIC MARGIN 2006	2005	CHANGE	PERCENT CHANGE
Electric operating revenue[1]	$ 1,777.7	$ 1,612.9	$ 164.8	10.2 %
Less: Other electric operating revenue	(51.8)	(62.5)	10.7	17.1
Add: Other electric operating revenue – gas supply resale	16.4	26.1	(9.7)	(37.2)
Total electric revenue for margin	1,742.3	1,576.5	165.8	10.5
Adjustments for amounts included in revenue:				
Pass-through tariff items	(35.9)	(26.9)	(9.0)	(33.5)
Pass-through revenue-sensitive taxes	(117.4)	(104.9)	(12.5)	(11.9)
Net electric revenue for margin	1,589.0	1,444.7	144.3	10.0
Minus power costs:				
Purchased electricity[1]	(917.8)	(860.4)	(57.4)	(6.7)
Electric generation fuel[1]	(97.3)	(73.3)	(24.0)	(32.7)
Residential exchange[1]	163.6	180.5	(16.9)	(9.4)
Total electric power costs	(851.5)	(753.2)	(98.3)	(13.1)
Electric margin[2]	$ 737.5	$ 691.5	$ 46.0	6.7 %

1 *As reported on PSE's Consolidated Statement of Income.*

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

Electric margin increased $46.0 million in 2006 compared to 2005 primarily due to the effects of the general rate case rate increase effective March 4, 2005 and the PCORC rate increases effective November 1, 2005 and July 1, 2006 which increased margin by $27.5 million. Retail customer kilowatt hour (kWh) sales (residential, commercial and industrial customers) increased 3.1% in 2006 compared to 2005, which provided $21.8 million to electric margin. Electric margin also increased by $12.9 million due to overrecovery of excess power cost under the PCA mechanism. Electric margin increased by $1.2 million due to the reduction of the Tenaska disallowance in the PCA mechanism. These increases were partially offset by a $11.2 million decrease related to production tax credits (PTCs) provided to customers through tariff rates, which are trued-up to actual PTCs taken in an annual true-up process 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 following table displays the details of gas margin changes from 2005 to 2006. 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) TWELVE MONTHS ENDED DECEMBER 31	GAS MARGIN 2006	2005	CHANGE	PERCENT CHANGE
Gas operating revenue[1]	$ 1,120.1	$ 952.5	$ 167.6	17.6%
Less: Other gas operating revenue	(16.5)	(17.2)	0.7	4.1
Total gas revenue for margin	1,103.6	935.3	168.3	18.0
Adjustments for amounts included in revenue:				
Pass-through tariff items	(7.1)	(5.7)	(1.4)	(24.6)
Pass-through revenue-sensitive taxes	(86.3)	(73.1)	(13.2)	(18.1)
Net gas revenue for margin	1,010.2	856.5	153.7	17.9
Minus purchased gas costs[1]	(723.2)	(592.1)	(131.1)	(22.1)
Gas margin[2]	$ 287.0	$ 264.4	$ 22.6	8.5%

1 *As reported on PSE's Consolidated Statement of Income.*

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

Gas margin increased $22.6 million in 2006 compared to 2005. Gas margin increased $12.6 million due to a 4.7% 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. These increases were partially offset by a $1.5 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 from 2005 to 2006.

(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31	2006	2005	CHANGE	PERCENT CHANGE
Electric operating revenues:				
Residential sales	$ 788.2	$ 690.2	$ 98.0	14.2%
Commercial sales	702.8	629.0	73.8	11.7
Industrial sales	103.0	93.9	9.1	9.7
Other retail sales, including unbilled revenue	35.4	23.3	12.1	51.9
Total retail sales	1,629.4	1,436.4	193.0	13.4
Transportation sales	11.5	9.0	2.5	27.8
Sales to other utilities and marketers	85.0	105.0	(20.0)	(19.0)
Other	51.8	62.5	(10.7)	(17.1)
Total electric operating revenues	$ 1,777.7	$ 1,612.9	$ 164.8	10.2%

Electric retail sales increased $193.0 million for 2006 compared to 2005 due primarily to rate increases related to the PCORC and the electric general rate case and increased retail customer usage. The PCORC and electric general rate case provided a combined additional $68.7 million to electric operating revenues for 2006 compared to 2005. Retail electricity usage increased 626,207 MWh or 3.1% for 2006 compared to 2005. The increase in electricity usage was mainly the result of a 1.6% higher average number of customers served in 2006 compared to 2005.

During 2006, the benefits of the Residential and Small Farm Energy Exchange Benefit credited to customers reduced electric operating revenues by $171.3 million compared to $189.0 million for 2005. This credit also reduced power costs by a corresponding amount with no impact on earnings.

Transportation sales increased $2.5 million for 2006 compared to 2005 due to an increase in sales volume of 61,524 MWh or 3.0%.

Sales to other utilities and marketers decreased $20.0 million compared to 2005 due primarily to a decrease in the wholesale market price of electricity in 2006 as compared to 2005 offset by an increase of 180,842 MWh in 2006 from 2005.

Other electric revenues decreased $10.7 million in 2006 compared to 2005, primarily associated with natural gas purchased for electric generation needs that was subsequently sold rather than used by PSE or gains from electric generation financial derivatives on gas sold. The following electric rate changes were approved by the Washington Commission in 2007, 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]
Electric General Rate Case	January 13, 2007	(1.3)%	(22.8)

[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 from 2005 to 2006.

(Dollars in Millions) Twelve Months Ended December 31	2006	2005	Change	Percent Change
Gas operating revenues:				
Residential sales	$ 697.6	$ 592.4	$ 105.2	17.8 %
Commercial sales	335.7	281.3	54.4	19.3
Industrial sales	57.1	48.3	8.8	18.2
Total retail sales	1,090.4	922.0	168.4	18.3
Transportation sales	13.3	13.3	--	0.0
Other	16.4	17.2	(0.8)	(4.7)
Total gas operating revenues	$ 1,120.1	$ 952.5	$ 167.6	17.6 %

Gas retail sales increased $168.4 million for 2006 compared to 2005 due to higher purchased gas adjustment (PGA) mechanism rates in 2006, approval of a 3.5% gas general rate increase effective March 4, 2005 and higher retail customer gas usage. The Washington Commission approved a PGA mechanism rate increase effective October 1, 2005 that provided $113.2 million in gas revenues for 2006 compared to 2005. In addition, the gas general rate case increase provided an additional $7.0 million in gas operating revenues for 2006 compared to in 2005. The remaining increase in gas retail revenues was primarily due to an increase in customers of 3.0% and higher gas sales of 48.4 million therms or $43.8 million for 2006 compared to 2005.

The following gas rate changes were approved by the Washington Commission in 2007, 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	October 1, 2006	10.2 %	95.1
Gas General Rate Case	January 13, 2007	2.8 %	29.5

OPERATING EXPENSES

The table below sets forth significant changes in operating expenses for PSE from 2005 to 2006.

(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31	2006	2005	CHANGE	PERCENT CHANGE
Purchased electricity	$ 917.8	$ 860.4	$ 57.4	6.7 %
Electric generation fuel	97.3	73.3	24.0	32.7
Residential exchange	(163.6)	(180.5)	16.9	9.4
Purchased gas	723.2	592.1	131.1	22.1
Utility operations and maintenance	354.6	333.3	21.3	6.4
Depreciation and amortization	262.3	241.6	20.7	8.6
Conservation amortization	32.3	24.3	8.0	32.9
Taxes other than income taxes	255.7	233.7	22.0	9.4
Income taxes	97.2	89.6	7.6	8.5

Purchased electricity expenses increased $57.4 million in 2006 compared to 2005 primarily due to a 3.1% increase in retail customer sales volumes and a 9.6% increase in wholesale sales volumes. Total purchased power for 2006 increased 904,560 MWh, or a 5.4% increase over 2005. Increase in the purchased power volumes offset by slightly lower wholesale prices caused an increase of $19.2 million in 2006. The increase in costs also reflected the recovery of previously deferred excess power costs of $12.7 million due to lower power costs in 2006 than the baseline PCA mechanism rate as compared to a deferral of excess power costs of $15.7 million in 2005. Also contributing to the increase in costs was a Washington Commission order that allowed PSE to reflect additional power costs totaling $6.0 million during the PCA 2 period of July 1, 2003 through December 31, 2003, in 2005. In addition, transmission and other expenses increased $5.0 million due in part to increased kWh sales to customers.

PSE's hydroelectric production and related power costs in 2006 were positively impacted by above-normal precipitation and snow pack in the Pacific Northwest region, which resulted in the runoff above Grand Coulee Reservoir to be 106.0% of normal as compared to a below normal runoff of 88.0% in 2005. The January Early Bird Columbia Basin Runoff Forecast published by the National Weather Service Northwest River Forecast Center indicated that the total forecasted runoff above Grand Coulee Reservoir for the period January through July 2007 would be near historical averages.

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 $24.0 million in 2006 compared to 2005 primarily due to an increase of $17.4 million in the cost of fuel at PSE-controlled combustion turbine generating facilities due to higher costs of natural gas offset by slightly lower volumes of electricity generated and an increase in the cost of coal at Colstrip generating facilities of $6.6 million compared to 2005.

Residential exchange credits associated with the Residential Purchase and Sale Agreement with the Bonneville Power Association (BPA) decreased $16.9 million in 2006 compared to 2005 as a result of lower residential and small farm customer electric rates. 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 BPA decreased 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 $131.1 million in 2006 compared to 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 December 31, 2006 and December 31, 2005 was $39.8 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. For further discussion on PGA rates see Item 1 – Business - Gas Regulation and Rates.

Utility operations and maintenance expense increased $21.3 million in 2006 compared to 2005 primarily due to higher production costs of $11.9 million related to a major overhauls of Colstrip Units 1 and 4, the Hopkins Ridge wind project which became operational on November 26, 2005, soil remediation costs at PSE's Crystal Mountain electric generation station site and costs to repair a failure of PSE's Whitehorn Unit 2 combustion turbine generator. $7.2 million of the increase was due to higher electric distribution system restoration costs as a result of a series of severe winter storms. In addition, customer service and call center costs increased $3.8 million and gas operations and distribution costs increased $2.0 million. These increases were slightly offset by a decrease of $3.6 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.

A series of severe wind storms occurred during 2006 for which PSE incurred significant costs, including a wind storm that occurred in December 2006 that resulted in a loss of electric service to over 700,000 of PSE's customers. PSE incurred over $72.0 million in estimated costs related to this wind storm, the majority of which were deferred in accordance with the Washington Commission's orders. In total, PSE deferred $92.3 million of storm costs in 2006 as a result of a Washington Commission order that allowed deferral of qualified storm costs in excess of $7.0 million. Qualifying storm costs are those that exceed the Institute of Electrical and Electronics Engineers (IEEE) standard for determining system average interruption duration index.

Conservation amortization increased $8.0 million in 2006 compared to 2005 due to higher authorized recovery of electric conservation expenditures. Conservation amortization is a pass-through tariff item with no impact on earnings.

Depreciation and amortization expense increased $20.7 million in 2006 compared to 2005 due primarily to the effects of new generating and electric and gas distribution system plant placed in service, of which $8.1 million is from placing the Hopkins Ridge wind project in service on November 26, 2005.

Taxes other than income taxes increased $22.0 million in 2006 compared to 2005 primarily due to increases in revenue-based Washington State excise tax and municipal tax due to increased operating revenues. Revenue sensitive excise and municipal taxes have no impact on earnings. Excluding the impact of revenue sensitive taxes, taxes other than income taxes decreased $3.8 million primarily as a result of 2006 property tax reduction settled with the Washington State Department of Revenue in August 2006 which resulted in a lower valuation for tax purposes in 2006 as compared to 2005.

Income taxes increased $7.6 million in 2006 compared to 2005 was the result of higher taxable income slightly offset by a lower effective tax rate influenced by PTCs and the true-up of the prior year federal income tax provision which resulted in an expense in 2006 versus a benefit in 2005.

OTHER INCOME, OTHER EXPENSES, OTHER INCOME TAXES AND INTEREST CHARGES

The table below sets forth significant changes in other income and interest charges for PSE from 2005 to 2006.

(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31	2006	2005	CHANGE	PERCENT CHANGE
Other income	$ 29.6	$ 16.8	12.8	76.2 %
Other expenses	(10.0)	(11.1)	1.1	9.9
Income taxes	(1.4)	2.6	(4.0)	*
Interest charges	169.0	165.0	4.0	2.4

* *Percent change not applicable or meaningful.*

Other income increased $12.8 million in 2006 compared to 2005 primarily due to an increase in the accrual of carrying costs on regulatory assets and an increase in the equity portion of allowance for funds used during construction (AFUDC).

Other expenses decreased by $1.1 million due to a decrease in long-term share based incentive plan costs offset by certain regulatory penalty expenses incurred in 2006.

Income taxes on other income and expenses increased $4.0 million in 2006 as compared to 2005 is a result of the increase in other income.

Interest charges increased $4.0 million in 2006 compared to 2005 due primarily to interest expense of $6.4 million related to an increase in debt due to construction projects offset by an increase in the debt AFUDC credit. .

INFRASTRUX

On May 7, 2006, Puget Energy sold its 90.9% interest in InfrastruX to an affiliate of Tenaska, resulting in after-tax cash proceeds of approximately $95.9 million, an after-tax gain of $29.8 million for 2006. 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 remains obligated for certain representations and warranties made by InfrastruX concerning its business through May 7, 2008. Puget Energy obtained a representation and warranty insurance policy and deposited $3.7 million into an escrow account as retention under the policy. As of December 31, 2006, long-term restricted cash in the amount of $3.8 million is included in the accompanying balance sheets and represents Puget Energy's maximum exposure related to those commitments. Puget Energy also agreed to indemnify the purchaser for certain potential future losses related to one of InfrastruX's subsidiaries through May 7, 2011, with the maximum amount of loss not to exceed $15.0 million. A liability in the amount of $5.0 million is included in the accompanying balance sheets as of December 31, 2006, which 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. Puget Energy also provided an environmental guarantee as part of the sale agreement. Puget Energy believes it will not have a future loss in connection with the environmental guarantee.

For 2006, Puget Energy reported InfrastruX related income from discontinued operations, including gain on sale, of $51.9 million compared to $9.5 million for 2005 (in each case, net of taxes and minority interest). Puget Energy's income from discontinued operations for 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.

InfrastruX's operating revenue through May 7, 2006 was $138.6 million compared to $393.3 million for the twelve months ended December 31, 2005. Pre-tax income for the twelve months ended December 31, 2006 was $9.9 million compared to $36.4 million for the same period in 2005.

PUGET SOUND ENERGY
2005 COMPARED TO 2004

ENERGY MARGINS

The following table displays the details of electric margin changes from 2004 to 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) TWELVE MONTHS ENDED DECEMBER 31	ELECTRIC MARGIN 2005	2004	CHANGE	PERCENT CHANGE
Electric operating revenue[1]	$ 1,612.9	$ 1,423.0	$ 189.9	13.3 %
Less: Other electric operating revenue	(62.5)	(44.8)	(17.7)	(39.5)
Add: Other electric revenue-gas supply resale	26.1	11.4	14.7	128.9
Total electric revenue for margin	1,576.5	1,389.6	186.9	13.4
Adjustments for amounts included in revenue:				
Pass-through tariff items	(26.9)	(25.4)	(1.5)	(5.9)
Pass-through revenue-sensitive taxes	(104.9)	(94.2)	(10.7)	(11.4)
Net electric revenue for margin	1,444.7	1,270.0	174.7	13.8
Minus power costs:				
Purchased electricity[1]	(860.4)	(723.6)	(136.8)	(18.9)
Electric generation fuel[1]	(73.3)	(80.8)	7.5	9.3
Residential exchange[1]	180.5	174.5	6.0	3.4
Total electric power costs	(753.2)	(629.9)	(123.3)	(19.6)
Electric margin[2]	$ 691.5	$ 640.1	$ 51.4	8.0 %

1 *As reported on PSE's Consolidated Statement of Income.*

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

Electric margin increased $51.4 million in 2005 compared to 2004 primarily as a result of the Tenaska disallowance recorded in May 2004, and ongoing Tenaska disallowances, which reduced margin by $43.4 million for 2004 compared to $4.1 million in 2005. Other items that increased margin include a 3.0% increase in retail customer usage which contributed $18.7 million to margin. These increases were partially offset by a reduction in transmission and transportation revenues in 2005 compared to 2004 which reduced electric margin by $2.7 million. Customers also received a reduction in revenue of $2.6 million related to production tax credits for the Hopkins Ridge wind generating facility which lowered electric revenue and margin. These credits vary quarter to quarter and over time the amounts credited to customers through lower electric rates will equal the amount used for federal income taxes. A lower authorized return on electric generating facilities that became effective on March 4, 2005 also lowered electric margin by $2.3 million.

The following table displays the details of gas margin changes from 2004 to 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) TWELVE MONTHS ENDED DECEMBER 31	GAS MARGIN 2005	2004	CHANGE	PERCENT CHANGE
Gas operating revenue	$ 952.5	$ 769.3	$ 183.2	23.8%
Less: Other gas operating revenue	(17.2)	(12.7)	(4.5)	(35.4)
Total gas revenue for margin[1]	935.3	756.6	178.7	23.6
Adjustments for amounts included in revenue:				
Pass-through tariff items	(5.7)	(3.6)	(2.1)	(58.3)
Pass-through revenue-sensitive taxes	(73.1)	(59.3)	(13.8)	(23.3)
Net gas revenue for margin	856.5	693.7	162.8	23.5
Minus purchased gas costs[1]	(592.1)	(451.3)	(140.8)	(31.2)
Gas margin[2]	$ 264.4	$ 242.4	$ 22.0	9.1%

1 *As reported on PSE's Consolidated Statement of Income.*

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

Gas margin increased $22.0 million for 2005 compared to 2004. Gas margin increased $17.3 million as a result of the gas general tariff rate increase of 3.5% effective March 4, 2005. In addition, therm sales increased 2.4% for 2005 compared to 2004, which provided $5.8 million to gas margin and changes in customer class usage provided $3.9 million to gas margin.

ELECTRIC OPERATING REVENUES

The table below sets forth changes in electric operating revenues for PSE from 2004 to 2005.

(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31	2005	2004	CHANGE	PERCENT CHANGE
Electric operating revenues:				
Residential sales	$ 690.2	$ 628.9	$ 61.3	9.7 %
Commercial sales	629.0	581.0	48.0	8.3
Industrial sales	93.9	88.8	5.1	5.7
Other retail sales, including unbilled revenue	23.3	12.2	11.1	91.0
Total retail sales	1,436.4	1,310.9	125.5	9.6
Transportation sales	9.0	10.7	(1.7)	(15.9)
Sales to other utilities and marketers	105.0	56.5	48.5	85.8
Other	62.5	44.9	17.6	39.2
Total electric operating revenues	$ 1,612.9	$ 1,423.0	$ 189.9	13.3 %

Electric retail sales increased $125.5 million for 2005 compared to 2004 due primarily to rate increases related to the PCORC and the electric general rate case and increased retail customer usage. The PCORC and electric general rate case provided a combined additional $66.5 million to electric operating revenues for 2005 compared to 2004, which provided approximately $24.5 million in electric operating revenues. Retail electricity usage increased 588,645 MWh or 3.0% for 2005 compared to 2004. The increase in electricity usage was mainly the result of a 1.8% higher average number of customers served in 2005 compared to 2004.

During 2005, the benefits of the Residential and Small Farm Energy Exchange Benefit credited to customers reduced electric operating revenues by $189.0 million compared to $182.6 million for 2004. This credit also reduced power costs by a corresponding amount with no impact on earnings.

Sales to other utilities and marketers increased $48.5 million compared to 2004 primarily due to an increase of 569,613 MWh sold related to excess generation and energy available for sale on the wholesale market. This resulted primarily from normal streamflows for hydroelectric generation in the third quarter as compared to below normal streamflows that were expected. The increase in MWh sold was due to differences in timing of the need for power to serve base load and actual weather conditions.

Other electric revenues increased $17.6 million for 2005 compared to 2004, primarily from the sale of excess non-core gas purchased for intended electric generation. Non-core gas sales are included in the PCA mechanism calculation as a reduction in determining costs.

The following electric rate changes were approved by the Washington Commission in 2005 and 2004:

Type of Rate Adjustment	Effective Date	Average Percentage Increase in Rates	Annual Increase in Revenues (Dollars in Millions)
Power Cost Only Rate Case	May 24, 2004	3.2 %	$ 44.1
Electric General Rate Case	March 4, 2005	4.1 %	57.7
Power Cost Only Rate Case	November 1, 2005	3.7 %	55.6

Gas Operating Revenues

The table below sets forth changes in gas operating revenues for PSE from 2004 to 2005.

(Dollars in Millions) Twelve Months Ended December 31	2005	2004	Change	Percent Change
Gas operating revenues:				
Residential sales	$ 592.4	$ 479.0	$ 113.4	23.7 %
Commercial sales	281.3	225.8	55.5	24.6
Industrial sales	48.3	38.8	9.5	24.5
Total retail sales	922.0	743.6	178.4	24.0
Transportation sales	13.3	13.0	0.3	2.3
Other	17.2	12.7	4.5	35.4
Total gas operating revenues	$ 952.5	$ 769.3	$ 183.2	23.8 %

Gas retail sales increased $178.4 million for 2005 compared to 2004 due to higher PGA mechanism rates in 2005, approval of a 3.5% general gas rate increase in the gas general rate case effective March 4, 2005 and higher customer gas usage. The Washington Commission approved PGA mechanism rate increases effective October 1, 2004 that increased rates 17.6% 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 2005, the effects of the PGA mechanism rate increases provided an increase of $123.8 million in gas operating revenues. In addition, the gas general rate increase provided an additional $17.3 million in gas operating revenue for 2005 compared to 2004. An increase of 3.1% in the average number of customers and lower temperatures in 2005 increased retail customer usage by 27.2 million therms or approximately $25.0 million in retail gas operating revenues.

The following gas rate adjustments were approved by the Washington Commission in 2005 and 2004:

Type of Rate Adjustment	Effective Date	Average Percentage Increase in Rates	Annual Increase in Revenues (Dollars in Millions)
PGA	October 1, 2004	17.6 %	$ 121.7
Gas General Rate Case	March 4, 2005	3.5 %	26.3
PGA	October 1, 2005	14.7 %	121.6

OPERATING EXPENSES

The table below sets forth significant changes in operating expenses for PSE from 2004 to 2005.

(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31	2005	2004	CHANGE	PERCENT CHANGE
Purchased electricity	$ 860.4	$ 723.6	$ 136.8	18.9 %
Electric generation fuel	73.3	80.8	(7.5)	(9.3)
Residential exchange	(180.5)	(174.5)	(6.0)	(3.4)
Purchased gas	592.1	451.3	140.8	31.2
Utility operations and maintenance	333.3	291.2	42.1	14.5
Depreciation and amortization	241.6	228.6	13.0	5.7
Taxes other than income taxes	233.7	209.0	24.7	11.8
Income taxes	89.6	77.1	12.5	16.2

Purchased electricity expenses increased $136.8 million in 2005 compared to 2004 as a result of increased power purchases from higher customer usage and higher wholesale market prices offset by a reduction in the Tenaska disallowance related to the return on the Tenaska gas supply regulatory asset. The reduction of $39.3 million related to the Tenaska disallowance from 2004 included a February 23, 2005 Washington Commission order concerning PSE's compliance filing related to the PCA 2 period of July 1, 2003 through June 30, 2004. In its order, the Washington Commission determined that PSE was allowed to reflect additional power costs totaling $6.0 million during the PCA 2 period of July 1, 2003 through December 31, 2003. These costs were reflected in the PCA mechanism, which resulted in a reduction in purchased electricity expense for 2005. Total purchased power for 2005 increased 1,336,501 MWh, or an 8.6% increase over 2004.

PSE's hydroelectric production and related power costs in 2005 and 2004 were negatively impacted by below-normal precipitation and reduced snow pack in the Pacific Northwest region. The January 4, 2006 Columbia Basin Runoff Summary published by the National Weather Service Northwest River Forecast Center indicated that the total observed runoff above Grand Coulee Reservoir for 2005 was 88.0% of normal, which approximates the total observed runoff for 2004.

Electric generation fuel expense decreased $7.5 million in 2005 compared to 2004 primarily due to a $6.9 million charge recorded in 2004 related to a binding arbitration settlement between Western Energy Company and PSE. Excluding this settlement, electric generation fuel costs decreased $0.6 million related to overall lower cost of gas for combustion turbine units and cost of gas at those facilities totaling $5.6 million. The decrease in lower cost of gas was partially offset by an increase of the cost of coal of $5.0 million in 2005 compared to 2004 due to higher generation at Colstrip generating facilities of 56,797 MWh. Costs associated with electric generation fuel are reflected in the PCA mechanism.

The reduction in electric generation fuel was also the result of the Hopkins Ridge wind generation facility beginning operations on November 27, 2005. Generation from the Hopkins Ridge generation facility does not include fuel expenses in its operation.

Residential exchange credits associated with the Residential Purchase and Sale Agreement with BPA increased $6.0 million in 2005 compared to 2004 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.

Purchased gas expenses increased $140.8 million in 2005 compared to 2004 primarily due to an increase in PGA rates as approved by the Washington Commission. 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 December 31, 2005 and 2004 was $67.3 million and $19.1 million, respectively. A receivable balance in the PGA mechanism reflects a current underrecovery of market gas cost through rates.

Utility operations and maintenance expense increased $42.1 million in 2005 compared to 2004 which includes an increase of $4.3 million related to low-income program costs that are passed-through in retail rates with no impact on earnings. As a result, the impact on net income from utility operations and maintenance for 2005 was an increase of $37.7 million. The increase for 2005 includes increases of $26.2 million related to higher gas distribution system expenses, planned maintenance costs for PSE-owned energy production facilities, electric distribution system costs, regulatory commission expense for rate cases and administrative costs. The production operation and maintenance increase for 2005 also includes a $1.5 million loss reserve associated with an arbitration panel's ruling in favor of the Muckleshoot Indian Tribe relating to the operation of a fish hatchery on the White River recorded in the second quarter 2005. These increases were partially offset by lower storm damage repair costs of $5.5 million for 2005 due to less severe weather and outages. Total storm damage costs for 2005 totaled $3.6 million compared to $9.1 million in 2004.

Depreciation and amortization expense increased $13.0 million in 2005 compared to 2004 due primarily to the effects of new generating and electric and gas distribution system plant placed in service in 2005. New plant placed in service in 2005 includes $170.9 million for the Hopkins Ridge wind project in November 2005.

Taxes other than income taxes increased $24.7 million in 2005 compared to 2004 primarily due to increases in revenue-based Washington State excise tax and municipal tax due to increased operating revenues. Revenue sensitive excise and municipal taxes have no impact on earnings.

Income taxes increased $12.5 million in 2005 compared to 2004 as a result of higher taxable income and the non-recurrence of the one-time income tax benefit of $1.4 million in 2004 related to a 2001 tax audit.

OTHER INCOME AND INTEREST CHARGES

The table below sets forth significant changes in other income and interest charges for PSE from 2005 to 2004.

(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31	2005	2004	CHANGE	PERCENT CHANGE
Other income	$ 16.8	$ 11.0	$ 5.8	52.7 %
Other expenses	(11.1)	(9.5)	(1.6)	(16.8)
Interest charges	165.0	166.4	(1.4)	(0.8)

Other income increased $5.8 million in 2005 compared to 2004 primarily due to increases in the equity portion of allowance for funds used during construction and an increase in revenue from PSE's basic ordering agreement for energy management projects with the U.S. Navy.

Other expenses decreased by $1.6 million primarily due to a decrease in long-term incentive plan costs due to not meeting the performance condition.

Interest charges decreased $1.4 million in 2005 compared to 2004 due to the redemption of $231.0 million of long-term debt with rates ranging from 3.40% to 6.93% in 2005. Also, in May 2005, PSE redeemed $42.5 million of PSE's 8.231% Capital Trust Preferred Securities (classified as Junior Subordinated Debentures of the Corporation Payable to a Subsidiary Trust Holding Mandatorily Redeemable Preferred Securities on the balance sheet). These redemptions and resulting decreases in interest expense were partially offset by the issuance of $250.0 million and $150.0 million of long-term senior notes in May 2005 and October 2005, respectively. In addition, debt AFUDC credited to interest expense increased $4.1 million due to increased construction activity in 2005.

INFRASTRUX
2005 COMPARED TO 2004

The following table summarizes Puget Energy's income from discontinued operations for 2005 and 2004:

(DOLLARS IN MILLIONS)	2005	2004
Income from operations reported by InfrastruX	$ 11.4	$ 6.8
Goodwill impairment	(13.9)	(91.2)
Tax provision on goodwill impairment	--	24.9
Net (loss) at InfrastruX	(2.5)	(59.5)
Goodwill impairment not recognized at Puget Energy	13.9	--
InfrastruX depreciation and amortization not recorded by Puget Energy, net of tax	10.8	--
Puget Energy tax benefit (valuation allowance) from goodwill impairment	1.9	(18.0)
Carrying value adjustment to estimated fair value and transaction costs	(12.4)	--
Minority interest in income from discontinued operations	(2.2)	7.1
Income (loss) from discontinued operations	$ 9.5	$ (70.4)

In accordance with Statement of Financial Accounting Standards (SFAS) No. 144, Puget Energy adjusted the carrying value of its investment in InfrastruX to the estimate of fair value, less cost to sell, at December 31, 2005. After reflecting a $12.4 million carrying value adjustment and charge for transaction costs in 2005, Puget Energy's equity investment in InfrastruX was $43.5 million at December 31, 2005 compared to $33.8 million at December 31, 2004. Puget Energy's carrying value under SFAS No. 144 as compared to the estimated fair value of its InfrastruX investment was not impacted by the non-cash goodwill impairment recorded by InfrastruX under SFAS No. 142 due to discontinued operations of InfrastruX. As a result, Puget Energy did not record the effects of the goodwill impairment under SFAS No. 142 in 2005.

CAPITAL RESOURCES AND LIQUIDITY

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 December 31:

Puget Energy		PAYMENTS DUE PER PERIOD			
CONTRACTUAL OBLIGATIONS (DOLLARS IN MILLIONS)	Total	2007	2008-2009	2010-2011	2012 & Thereafter
Long-term debt including interest	$ 5,444.4	$ 294.9	$ 654.8	$ 741.0	$ 3,753.7
Short-term debt including interest	328.1	328.1	--	--	--
Junior subordinated debentures payable to a subsidiary trust including interest[1]	101.2	3.1	6.2	6.2	85.7
Mandatorily redeemable preferred stock	1.9	--	--	--	1.9
Service contract obligations	159.8	30.7	69.0	45.6	14.5
Non-cancelable operating leases	120.3	15.5	50.3	21.4	33.1
Fredonia combustion turbines lease [2]	65.4	6.1	12.5	46.8	--
Energy purchase obligations	6,176.3	1,001.1	1,666.3	992.3	2,516.6
Contract initiation payment/collateral requirement	18.5	--	--	18.5	--
Financial hedge obligations	3.6	2.2	1.4	--	--
Purchase obligations	44.6	10.5	34.1	--	--
Non-qualified pension and other benefits funding and payments	47.2	6.6	7.4	9.1	24.1
Total contractual cash obligations	$ 12,511.3	$ 1,698.8	$ 2,502.0	$ 1,880.9	$ 6,429.6

Puget Energy		Amount of Commitment Expiration Per Period			
Commercial Commitments (Dollars in Millions)	Total	2007	2008-2009	2010-2011	2012 & Thereafter
Indemnity agreements [3]	$ 8.8	$ --	$ 3.8	$ --	$ 5.0
Credit agreement - available [4]	281.5	--	--	281.5	--
Receivable securitization facility[5]	90.0	--	--	90.0	--
Energy operations letter of credit	0.5	0.5	--	--	--
Total commercial commitments	$ 380.8	$ 0.5	$ 3.8	$ 371.5	$ 5.0

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 $3.8 million at December 31, 2006 and the obligation expires on May 7, 2008. Puget Energy also agreed to indemnify the buyer relating to an inquiry of an InfrastruX subsidiary and the fair value of the warranty was $5.0 million at December 31, 2006. See "InfrastruX" above for further discussion.*

4 *At December 31, 2006, PSE had available a $500.0 million unsecured credit agreement expiring in April 2011. The credit agreement provides credit support for letters of credit and commercial paper. At December 31, 2006, PSE had $0.5 million for an outstanding letter of credit and $218.0 million commercial paper outstanding, effectively reducing the available borrowing capacity to $281.5 million.*

5 *At December 31, 2006, PSE had available a $200.0 million receivables securitization facility that expires in December 2010. $110.0 million was outstanding under the receivables securitization facility at December 31, 2006 thus leaving $90.0 million available. The facility allows receivables to be used as collateral to secure short-term loans, not exceeding the lesser of $200.0 million or the borrowing base of eligible receivables, which fluctuate with the seasonality of energy sales to customers. See "Receivables Securitization Facility" below for further discussion.*

Puget Sound Energy. The following are PSE's aggregate contractual obligations and commercial commitments as of December 31:

Puget Sound Energy		Payments Due Per Period			
Contractual Obligations (Dollars in Millions)	Total	2007	2008-2009	2010-2011	2012 & Thereafter
Long-term debt including interest	$ 5,444.4	$ 294.9	$ 654.8	$ 741.0	$ 3,753.7
Short-term debt including interest	352.5	352.5	--	--	--
Junior subordinated debentures payable to a subsidiary trust including interest[1]	101.2	3.1	6.2	6.2	85.7
Mandatorily redeemable preferred stock	1.9	--	--	--	1.9
Service contract obligations	159.8	30.7	69.0	45.6	14.5
Non-cancelable operating leases	120.3	15.5	50.3	21.4	33.1
Fredonia combustion turbines lease [2]	65.4	6.1	12.5	46.8	--
Energy purchase obligations	6,176.3	1,001.1	1,666.3	992.3	2,516.6
Contract initiation payment/collateral requirement	18.5	--	--	18.5	--
Financial hedge obligations	3.6	2.2	1.4	--	--
Purchase obligations	44.6	10.5	34.1	--	--
Non-qualified pension and other benefits funding and payments	47.2	6.6	7.4	9.1	24.1
Total contractual cash obligations	$ 12,535.7	$ 1,723.2	$ 2,502.0	$ 1,880.9	$ 6,429.6

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

Puget Sound Energy COMMERCIAL COMMITMENTS (DOLLARS IN MILLIONS)	Total	AMOUNT OF COMMITMENT EXPIRATION PER PERIOD 2007	2008-2009	2010-2011	2012 & Thereafter
Credit agreement - available [3]	$ 281.5	$ --	$ --	$ 281.5	$ --
Receivable securitization facility[4]	90.0	--	--	90.0	--
Energy operations letter of credit	0.5	0.5	--	--	--
Total commercial commitments	$ 372.0	$ 0.5	$ --	$ 371.5	$ --

1 *See note 1 above.*
2 *See note 2 above.*
3 *See note 4 above.*
4 *See note 5 above.*

OFF-BALANCE SHEET ARRANGEMENTS

Fredonia 3 and 4 Operating Lease. PSE leases two combustion turbines for its Fredonia 3 and 4 electric generating facility pursuant to a master operating lease that was amended for this purpose in April 2001. The lease has a term expiring in 2011, but can be canceled by PSE at any time. Payments under the lease vary with changes in the London Interbank Offered Rate (LIBOR). At December 31, 2006, PSE's outstanding balance under the lease was $51.1 million. The expected residual value under the lease is the lesser of $37.4 million or 60.0% 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 87.0% 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 support reliability of PSE's energy delivery systems. Construction expenditures, excluding equity AFUDC and customer refundable contributions, were $575.1 million for 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 integrated resource planning process) are anticipated to be the following in 2007, 2008 and 2009:

CAPITAL EXPENDITURE PROJECTIONS (DOLLARS IN MILLIONS)	2007	2008	2009
Energy delivery, technology and facilities	$ 530	$ 555	$ 640
New resources	120	70	210
Total expenditures	$ 650	$ 625	$ 850

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 the new generation resources, are subject to periodic review and adjustment in light of changing economic, regulatory, environmental and efficiency factors.

NEW GENERATION RESOURCES

On December 22, 2006, PSE placed into service the Wild Horse wind project. Wild Horse is located in central Washington State. The Wild Horse wind project features 127 turbines providing up to 229 MW, generating enough wind-fueled electricity on average to serve 76,000 of the Company's electric customers in Western Washington and Kittitas County.

CAPITAL RESOURCES

CASH FROM OPERATIONS

Cash generated from operations for 2006 was $185.5 million, which is 23.7% of the $783.4 million used for utility construction expenditures and other capital expenditures. For 2005, cash generated from operations was $255.8 million which is 42.1% of the $608.0 million used for utility construction expenditures and other capital expenditures.

The overall cash generated from operating activities for 2006 decreased $70.3 million compared to 2005. The decrease was primarily attributable to deferred storm damage costs of $92.3 million and to a non-refundable capacity reservation payment of $89.0 million in April 2006 for the Chelan PUD power sales agreement which will begin providing power to PSE at the end of 2011. In addition, $37.7 million of cash collateral related to natural gas supply contracts was returned in 2006 and $55.0 million was received in 2005 for funds received from a gas pipeline capacity contract obligation of Duke Energy Marketing and Trading. Further, there was an increase of $83.4 million in payments made for accounts payable related to energy purchases which contributed to the decrease. Partially offsetting the decrease was an increase in accounts receivable balances of $139.7 million as compared to 2005 which was primarily attributable to the change in the accounts receivable securitization program. In addition, there was an increase in cash received for the purchased gas receivable adjustment of $75.8 million, a beneficial increase in the change of the power cost adjustment of $30.4 million, an increase in accrued expenses of $15.9 million and a decrease in BPA prepaid transmission of $10.8 million in 2005 that further offset the decrease in cash generated from operating activities.

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 depends 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, restated articles of incorporation and certain loan agreements. Under the most restrictive tests, at December 31, 2006, PSE could issue:

- approximately $262.0 million of additional first mortgage bonds under PSE's electric mortgage indenture based on approximately $437.0 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 December 31, 2006;
- approximately $365.0 million of additional first mortgage bonds under PSE's gas mortgage indenture based on approximately $608.0 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 December 31, 2006;
- approximately $802.8 million of additional preferred stock at an assumed dividend rate of 6.5%; and
- approximately $688.8 million of unsecured long-term debt.

At December 31, 2006, PSE had approximately $4.0 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

The ratings of Puget Energy and PSE, as of February 21, 2007, were:

	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 PSE's credit facilities*.

Neither Puget Energy nor PSE has any debt outstanding that would accelerate debt maturity upon a credit rating downgrade. However, 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.

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 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 $300.0 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 $300.0 million senior secured notes was 6.29% after the settlement of two forward starting swap contracts.

On June 30, 2006, PSE redeemed for $200.0 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 $25.0 par value per share plus accrued interest to the redemption date.

On June 30, 2006, PSE completed the issuance of $250.0 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 $200.0 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 $46.0 million of 8.06% senior notes that matured June 19, 2006. The yield to maturity of the $250.0 million senior secured notes was 6.17% after the settlement of two forward starting swap contracts.

Based on PSE's goal to become a more vertically integrated utility, it is expected that further issuances of debt, equity or a combination of the two will be necessary in the future. The structure, timing and amount of such financings depend on market conditions and financing needed.

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, $700.0 million in short-term borrowing capability. These include a $500.0 million credit agreement and a $200.0 million accounts receivable securitization facility. 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.

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 $30.0 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 December 31, 2006, the outstanding balance of the Note was $24.3 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, $500.0 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 which is also based on long-term credit ratings of PSE. At December 31, 2006, there was $0.5 million outstanding under a letter of credit and $218.0 million commercial paper outstanding, effectively reducing the available borrowing capacity under the credit facility to $281.5million.

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 $200.0 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 2006, PSE Funding borrowed a cumulative amount of $441.0 million secured by accounts receivable. There was $110.0 million in loans that were secured by accounts receivable pledged at December 31, 2006. The borrowing available under the receivables securitization at December 31, 2006 was $90.0 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's common stock. Since new shares of common stock may be purchased directly from Puget Energy, funds received may be used for general corporate purposes. Puget Energy issued common stock from the Stock Purchase and Dividend Reinvestment Plan of $13.5 million (615,648 shares) in 2006 compared to $14.5 million (656,267 shares) in 2005. The proceeds from sales of stock under these plans are used for general corporate needs.

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 (NYSE) at market prices.

OTHER

IRS Audit. As a matter of course, the Company's tax returns are routinely audited by federal, state and city tax authorities. In May of 2006, the IRS completed its examination of the company's 2001, 2002 and 2003 federal income tax returns. The Company is formally appealing two IRS audit adjustments. The first adjustment relates to the receivable balance due from the California Independent System Operator (CAISO). The IRS claims that the deduction was not valid for the 2003 tax year and would require repayment of approximately $14.5 million in tax. The Company believes the deduction is valid and intends to vigorously defend the deduction. Any potential tax payment (excluding interest) would have no impact on earnings, as it would be recognized as a deferred tax asset. If the Company is unsuccessful, a charge for interest expense would apply.

The second IRS audit adjustment relates to the company's accounting method with respect to capitalized internal labor and overheads. In its 2001 tax return, PSE claimed a deduction when it changed its tax accounting method with respect to capitalized internal labor and overheads. Under the new method, the Company could immediately deduct certain costs that it had previously capitalized. In the audit, the IRS disallowed the deduction. On August 2, 2005, the Internal Revenue Service and the Treasury Department issued Revenue Ruling 2005-53 and related Regulations. The Revenue Ruling and the Regulations required utility companies, including PSE, to adopt a less advantageous method of accounting and to repay the accumulated tax benefits. Through September 30, 2005, the Company claimed $66.3 million in accumulated tax benefits. PSE accounted for the accumulated tax benefits as temporary differences in determining its deferred income tax balances. Consequently, the repayment of the tax benefits did not impact earnings but did have a cash flow impact of $33.2 million in the fourth quarter 2005 and $33.1 million in 2006. As of December 31, 2006, the full tax benefit had been repaid. There is some uncertainty in the new guidance. PSE believes that the new Regulations required the Company to repay the accumulated tax benefits over the 2005 and 2006 tax years and that the tax deductions claimed on the Company's tax returns were appropriate based on the applicable statutes, Regulations and case law in effect at the time. However, there is no assurance that PSE's appeal will prevail. If the Company is unsuccessful, a charge for interest expense would apply.

On October 19, 2005, PSE filed an accounting petition with the Washington Commission to defer the capital costs associated with repayment of the deferred tax. The Washington Commission had reduced PSE's ratebase by $72.0 million in its order of February 18, 2005. The accounting petition was approved by the Washington Commission on October 26, 2005, for deferral of additional capital costs beginning November 1, 2005 using PSE's allowed net of tax rate of return. The Washington Commission granted cost recovery of these deferred carrying costs over two years, beginning January 13, 2007.

Tenaska Disallowance. The Washington Commission issued an order on May 13, 2004 determining that PSE did not prudently manage gas costs for the Tenaska electric generating plant and ordered PSE to adjust its PCA deferral account to reflect a disallowance of accumulated costs under the PCA mechanism for these excess costs. The increase in purchased electricity expense resulting from the disallowance totaled $9.0 million, $4.1 million and $43.4 million in 2006, 2005 and 2004, respectively. The order also established guidelines and a benchmark to determine PSE's recovery on the Tenaska regulatory asset starting with the PCA 3 period (July 1, 2004) through the expiration of the Tenaska contract in the year 2011. The benchmark is defined as the original cost of the Tenaska contract adjusted to reflect the 1.2% disallowance from a 1994 Prudence Order.

In August 2004 PSE filed the PCA 2 period compliance and received an order from the Washington Commission on February 23, 2005. In the PCA 2 compliance order, the Washington Commission approved the Washington Commission staff's recommendation for an additional return related to the Tenaska regulatory asset in the amount of $6.0 million related to the period July 1, 2003 through December 31, 2003.

The Washington Commission confirmed that if the Tenaska gas costs are deemed prudent, PSE will recover the full amount of actual gas costs and the recovery of the Tenaska regulatory asset even if the benchmark is exceeded. Due to fluctuations in forward market prices of gas, the amount and timing of any potential disallowance related to Tenaska can change significantly day to day. The projected costs and projected benchmark costs for Tenaska as of December 31, 2006 based on current forward market gas prices are as follows:

(DOLLARS IN MILLIONS)	2007	2008	2009	2010	2011
Projected Tenaska costs *	$ 208.6	$ 225.8	$ 218.8	$ 211.5	$ 201.7
Projected Tenaska benchmark costs	174.8	182.9	189.9	197.4	205.6
Over (under) benchmark costs	$ 33.8	$ 42.9	$ 28.9	$ 14.1	$ (3.9)
Projected 50% disallowance based on Washington Commission methodology	$ 7.8	$ 6.4	$ 4.9	$ 3.1	$ --

* *Projection will change based on market conditions of gas and replacement power costs.*

PROCEEDINGS RELATING TO THE WESTERN POWER MARKET

The following discussion summarizes the status as of the date of this report of ongoing proceedings relating to the western power markets to which PSE is a party. PSE is vigorously defending each of these cases. 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. Since 2001, PSE has held a receivable relating to unpaid bills for power that PSE sold in 2000 into the markets maintained by the CAISO. At December 31, 2006, the net receivable for such sales was approximately $21.2 million. PSE's ability to recover all or a portion of this amount is uncertain. At this time there is no reasonable basis under applicable financial accounting rules to adjust PSE's net receivable because the outcome of further court and FERC actions is uncertain and any likely financial impact cannot be quantified.

In 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). FERC also ordered that if the refunds required by the formula it adopted would cause a seller to recover less than its actual costs for the refund period, the seller is allowed to document its costs and limit its refund liability commensurately. Consistent with those orders, PSE filed a fuel cost adjustment claim and a portfolio cost claim. Recovery of those amounts is uncertain, but the amount owed to PSE under all FERC orders to date is included in the PSE net receivable amount. FERC has not issued a final order determining "who owes how much to whom" in the California Refund Proceeding, and it is not clear when such an order will be issued.

In the course of the California Refund Proceeding, FERC has issued dozens of orders. Most have been taken up on appeal before the United States Court of Appeals for the Ninth Circuit (Ninth Circuit), which has issued opinions on some issues in the last several years. These cases are described below in the section, "California Litigation."

California Litigation. *Lockyer v. FERC.* On September 9, 2004, the Ninth Circuit issued a decision on the California Attorney General's challenge to the validity of FERC's market-based rate system. This case was originally presented to FERC upon complaint that the adoption and implementation of market rate authority was flawed. FERC dismissed the complaint after all sellers refiled summaries of transactions with California entities during 2000 and 2001. The Ninth Circuit upheld FERC's authority to authorize sales of electric energy at market-based rates, but found the requirement that all sales at market-based rates be contained in quarterly reports filed with FERC to be integral to a market-based rate tariff. The California parties, among others, have interpreted the decision as providing authority to FERC to order refunds for different time frames and based on different rationales than are currently pending in the California Refund Proceedings, discussed above in "California Refund Proceeding." The decision itself remands to FERC the question of whether to allow refunds. On December 28, 2006, PSE and several other energy sellers filed a petition for a writ of certiorari to the U.S. Supreme Court. The U.S. Supreme Court has not yet acted on that petition. PSE cannot predict the scope, nature or ultimate resolution of this case. That additional uncertainty may make the outcomes of certain other western energy market cases less predictable than previously anticipated.

CPUC v. FERC. On August 2, 2006, the Ninth Circuit decided that FERC erred in excluding potential relief for tariff violations for periods that pre-dated October 2, 2000 and additionally ruled that FERC should consider remedies for transactions previously considered outside 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. The decision may also expose PSE to claims or liabilities for transactions outside the previously defined "refund period." At this time the ultimate financial outcome for PSE is unclear. The deadline for seeking rehearing of the August 2, 2006 decision is April 29, 2007, and it is likely that some parties will seek rehearing. In addition, parties have been engaged in court-sponsored settlement discussions, and those discussions may result in some settlements. 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.

California Class Actions. In 2002, Reliant Energy Services (Reliant) and Duke Energy Trading & Marketing (Duke) cross-complained against PSE in several class actions filed in California arising from the California energy crisis. Duke and Reliant settled the underlying cases and subsequently dismissed the cross-complaints against the cross-defendants, including PSE.

Orders to Show Cause. On June 25, 2003, FERC issued two show cause orders pertaining to its western market investigations that commenced individual proceedings against many sellers. One show cause order investigated 26 entities that allegedly had potential "partnerships" with Enron. PSE was not named in that show cause order. On January 22, 2004, FERC stated that it did not intend to proceed further against other parties.

The second show cause order named PSE (Docket No. EL03-169) and approximately 54 other entities that allegedly had engaged in potential "gaming" practices in the CAISO and California PX markets. PSE and FERC staff filed a proposed settlement of all issues pending against PSE in those proceedings on August 28, 2003. The proposed settlement, which admits no wrongdoing on the part of PSE, would result in a payment of a nominal amount to settle all claims. FERC approved the settlement on January 22, 2004. The California parties filed for rehearing of that order. On March 17, 2004, PSE moved to dismiss the California parties' rehearing request and awaits FERC action on that motion.

Pacific Northwest Refund Proceeding. In October 2000, PSE filed a complaint at FERC (Docket No. EL01-10) against "all jurisdictional sellers" in the Pacific Northwest seeking prospective price caps consistent with any result FERC ordered for the California markets. FERC dismissed PSE's complaint, but PSE challenged that dismissal. On June 19, 2001, FERC ordered price caps on energy sales throughout the West. Various parties, including the Port of Seattle and the cities of Seattle and Tacoma, then moved to intervene in the proceeding seeking retroactive refunds for numerous transactions. The proceeding became known as the "Pacific Northwest Refund Proceeding," though refund claims were outside the scope of the original complaint. On June 25, 2003, FERC terminated the proceeding on procedural, jurisdictional and equitable grounds and on November 10, 2003, FERC on rehearing, confirmed the order terminating the proceeding. Petitions for review, including PSE's, are now pending before the Ninth Circuit. The Ninth Circuit held argument on the petitions on January 8, 2007, and the matter now awaits that court's decision.

Port of Seattle Suit. On May 21, 2003, the Port of Seattle commenced suit in federal court in Seattle against 22 energy sellers, including PSE, alleging that their conduct during 2000 and 2001 constituted market manipulation, violated antitrust laws and damaged the Port of Seattle. On May 12, 2004, the district court dismissed the lawsuit. The Port of Seattle filed an appeal to the Ninth Circuit. After briefing and oral argument on March 30, 2006, the Ninth Circuit issued an order dismissing the case.

Wah Chang Suit. In June 2004, Wah Chang, an Oregon company, filed suit in federal court against Puget Energy and PSE, among others. The complaint is similar to the allegations made by the Port of Seattle described above. The case was dismissed on the grounds that FERC has the exclusive jurisdiction over plaintiff's claims. On March 10, 2005, Wah Chang filed a notice of appeal to the Ninth Circuit. Oral argument is scheduled to take place on April 10, 2007.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in conformity with generally accepted accounting principles requires that management apply accounting policies and make estimates and assumptions that affect results of operations and the reported amounts of assets and liabilities in the financial statements. The following accounting policies represent those that management believes are particularly important to the financial statements and that require the use of estimates, assumptions and judgment to describe matters that are inherently uncertain.

Revenue Recognition. Utility revenues are recognized when the basis of service is rendered, which includes estimates to determine amounts relating to services rendered but not billed. Unbilled electricity revenue is determined by taking MWh generated and purchased less estimated system losses and billed MWh plus unbilled MWh balance at the last true-up date. The estimated system loss percentage for electricity is determined by reviewing historical billed MWh to generated and purchased MWh. The estimated unbilled MWh balance is then multiplied by the estimated average revenue per MWh. Unbilled gas revenue is determined by taking therms delivered to PSE less estimated system losses, prior month unbilled therms and billed therms. The estimated system loss percentage for gas is determined by reviewing historical billed therms to therms delivered to customers, which vary little from year to year. The estimated current month unbilled therms is then multiplied by estimated average rate schedule revenue per therm. Non-utility revenue is recognized when services are performed or upon the sale of assets. The recognition of revenue is in conformity with generally accepted accounting principles, which require the use of estimates and assumptions that affect the reported amounts of revenue.

Regulatory Accounting. As a regulated entity of the Washington Commission and FERC, PSE prepares its financial statements in accordance with the provisions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." The application of SFAS No. 71 results in differences in the timing and recognition of certain revenues and expenses in comparison with businesses in other industries. The rates that are charged by PSE to its customers are based on cost base regulation reviewed and approved by the Washington Commission and FERC. Under the authority of these commissions, PSE has recorded certain regulatory assets and liabilities at December 31, 2006 in the amount of $838.5 million and $191.6 million, respectively, and regulatory assets and liabilities of $674.3 million and $241.9 million, respectively, at December 31, 2005. PSE expects to fully recover these regulatory assets and liabilities through its rates. If future recovery of costs ceases to be probable, PSE would be required to write off these regulatory assets and liabilities. In addition, if at some point in the future PSE determines that it no longer meets the criteria for continued application of SFAS No. 71, PSE could be required to write off its regulatory assets and liabilities.

Also encompassed by regulatory accounting and subject to SFAS No. 71 are the PCA and PGA mechanisms. The PCA and PGA mechanisms mitigate the impact of commodity price volatility upon the Company and are approved by the Washington Commission. The PCA mechanism provides for a sharing of costs that vary from baseline rates over a graduated scale. See Item 1 – Business – Regulation and Rates – Electric Regulation and Rates for further discussion regarding the PCA mechanism. The PGA mechanism passes through to customers increases and decreases in the cost of natural gas supply. PSE expects to fully recover these regulatory assets through its rates. However, both mechanisms are subject to regulatory review and approval by the Washington Commission on a periodic basis.

Derivatives. Puget Energy uses derivative financial instruments primarily to manage its energy commodity price risks and may enter into certain financial derivatives to manage interest rate risk. Derivative financial instruments are accounted for under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138 and SFAS No. 149. Accounting for derivatives continues to evolve through guidance issued by the Derivatives Implementation Group (DIG) of the Financial Accounting Standards Board (FASB). To the extent that changes by the DIG modify current guidance, including the normal purchases and normal sales determination, the accounting treatment for derivatives may change.

To manage its electric and gas portfolios, Puget Energy enters into contracts to purchase or sell electricity and gas. These contracts are considered derivatives under SFAS No. 133 unless a determination is made that they qualify for the normal purchases and normal sales exception. If the exception applies, those contracts are not marked-to-market and are not reflected in the financial statements until delivery occurs.

The availability of the normal purchase and normal sale exception to specific contracts is based on a determination that a resource is available for a forward sale and similarly a determination that at certain times existing resources will be insufficient to serve load. This determination is based on internal models that forecast customer demand and generation supply. The models include assumptions regarding customer load growth rates, which are influenced by the economy, weather and the impact of customer choice and resource availability. The critical assumptions used in the determination of the normal purchases and normal sales exception are consistent with assumptions used in the energy portfolio management process.

Energy and financial contracts that are considered derivatives may be eligible for designation as cash flow hedges. If a contract is designated as a cash flow hedge, the change in its market value is generally deferred as a component of other comprehensive income until the transaction it is hedging is completed. Conversely, the change in the market value of derivatives not designated as cash flow hedges is recorded in current period earnings.

PSE values derivative instruments based on daily quoted prices from numerous independent energy brokerage services. When external quoted market prices are not available for derivative contracts, PSE uses a valuation model that uses volatility assumptions relating to future energy prices based on specific energy markets and utilizes externally available forward market price curves. All derivative instruments are sensitive to market price fluctuations that can occur on a daily basis.

Pension and Other Postretirement Benefits. Puget Energy has a qualified defined benefit pension plan covering substantially all employees of PSE. Qualified pension expense of $1.0 million was recorded in 2006 and income of $2.6 million and $8.0 million was recorded in the financial statements for 2005 and 2004, respectively. Of these amounts, approximately 56.6%, 63.0% and 63.3% offset utility operations and maintenance expense in 2006, 2005 and 2004, respectively, and the remaining amounts were capitalized. Qualified pension expense is expected to be $1.7 million in 2007.

PSE's pension and other postretirement benefits income or costs depend on several factors and assumptions, including plan design, timing and amount of cash contributions to the plan, earnings on plan assets, discount rate, expected long-term rate of return, mortality and health care cost trends. Changes in any of these factors or assumptions will affect the amount of income or expense that Puget Energy records in its financial statements in future years and its projected benefit obligation. The Company has selected an expected return on plan assets based on a historical analysis of rates of return and the Company's investment mix, market conditions, inflation and other factors. The Company's accounting policy for calculating the market-related value of assets is based on a five-year smoothing of asset gains/losses measured from the expected return on market-related assets. This is a calculated value that recognizes changes in fair value in a systematic and rational manner over five years. The same manner of calculating market-related value is used for all classes of assets, and is applied consistently from year to year. During 2006, PSE made no cash contributions to the qualified defined benefit plan and expects to make no contributions in 2007.

The following table reflects the estimated sensitivity associated with a change in certain significant actuarial assumptions (each assumption change is presented mutually exclusive of other assumption changes):

	CHANGE IN ASSUMPTION	IMPACT ON PROJECTED BENEFIT OBLIGATION INCREASE (DECREASE)		IMPACT ON 2006 PENSION INCOME INCREASE (DECREASE)	
(DOLLARS IN THOUSANDS)		Pension Benefits	Other Benefits	Pension Benefits	Other Benefits
Increase in discount rate	50 basis points	$ (23,144)	$ (3,291)	$ 2,014	$ 296
Decrease in discount rate	50 basis points	24,458	3,537	(2,188)	299
Increase in return of plan assets	50 basis points	*	*	2,277	73
Decrease in return on plan assets	50 basis points	*	*	(2,277)	(73)

* *Calculation not applicable.*

California Receivable. PSE operates within the western wholesale market and has made sales into the California energy market. At December 31, 2000, PSE's receivables from the CAISO and other counterparties was $41.8 million. PSE received the majority of the partial payments for sales made in the fourth quarter 2000 in the first quarter 2001 and has since received a small amount of payments. At December 31, 2006, such remaining receivables were approximately $21.2 million.

Based on the calculation of existing FERC orders issued to date, PSE has determined that the receivable balance at December 31, 2006 is collectible from the CAISO. However, PSE's ability to collect all or a portion of this amount may be impaired by future FERC orders or decisions by the Ninth Circuit.

Stock Compensation. 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 twelve months ended December 31, 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 twelve months ended December 31, 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.

NEW ACCOUNTING PRONOUNCEMENTS

At its June 15, 2006 meeting, FASB's 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)." The Company's policy is to report state utility taxes and municipal taxes on a gross basis. 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. The adoption of EITF Issue No. 06-3 is not expected to have a material impact on the Company's financial statements.

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 requires the use of a two-step approach for recognizing and measuring tax positions taken or expected to be taken in a tax return. First, the tax position 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. Second, a tax position, that meets the recognition threshold, should be measured at the largest amount that has a greater than 50.0% likelihood of being sustained.

FIN 48 was effective for the Company as of January 1, 2007. The change in net assets as a result of adopting FIN 48 will be treated as a change in accounting method. The cumulative effect of the change will be recorded to retained earnings. Adjustments to regulatory accounts, if any, will be based on other applicable accounting standards. The Company is currently in the process of evaluating the provisions of FIN 48 to determine the potential impact, if any, the adoption will have on the Company's financial statements. The adoption of FIN 48 is not expected to have a material impact on the Company's retained earnings. Management's estimated impact of adoption is subject to change due to potential changes in interpretation of FIN 48 by the FASB or other regulatory bodies and the finalization of the Company's adoption efforts.

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 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.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

ENERGY PORTFOLIO MANAGEMENT

The Company has energy risk policies and procedures to manage commodity and volatility risks. The Company's Energy Management Committee establishes the Company's energy risk management policies and procedures, and monitors compliance. The Energy Management Committee is comprised of certain Company officers and is overseen by the Audit Committee of the Company's Board of Directors.

The Company is focused on commodity price exposure and risks associated with volumetric variability in the gas and electric portfolios. It is not engaged in the business of assuming risk for the purpose of speculative trading. The Company hedges open gas and electric positions to reduce both the portfolio risk and the volatility risk in prices. The exposure position is determined by using a probabilistic risk system that models 100 scenarios of how the Company's gas and power portfolios will perform under various weather, hydro and unit performance conditions. The objective of the hedging strategy is:

- ensure physical energy supplies are available to reliably and cost-effectively serve retail load;
- prudent management of energy portfolio risks to serve retail load at overall least cost and limit undesired impacts on PSE's customers and shareholders; and
- reduce power costs by extracting the value of the Company's assets.

At December 31, 2006, the Company had a short-term asset of $0.9 million and a short-term liability of $0.9 million, primarily as a result of de-designating gas financial contracts. These contracts were related to electric generation that was no longer probable. During 2006, the Company recorded a decrease in earnings for the change in the market value of derivative instruments not meeting the normal purchase normal sale exception or cash flow hedge criteria under SFAS No. 133 of $0.1 million compared to a decrease in earnings of $0.5 million for 2005 and an increase of $0.5 million for 2004.

At December 31, 2006, PSE had a short-term asset of $9.2 million and a long-term asset of $6.8 million as well as a short-term liability of $8.0 million and a long-term liability of $0.4 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. These contracts were designated as qualifying cash flow hedges and a corresponding unrealized gain of $4.9 million, net of tax, was recorded in other comprehensive income. 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 December 31, 2005, the Company had an unrealized gain recorded in other comprehensive income of $43.2 million (net of tax), before SFAS No.71 deferrals of $6.3 million, related to energy contracts which met the criteria for designation as cash flow hedges under SFAS No. 133. This was mainly the result of higher forward market prices for natural gas and electricity at December 31, 2005 compared to December 31, 2006.

At December 31, 2006, the Company had a short-term asset of $6.8 million and a short-term liability of $61.6 million as well as a long-term asset of $0.1 million related to the hedges 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. All increases and decreases in the cost of natural gas supply are passed on to customers with the PGA mechanism. As the gains and losses on the hedges are realized in future periods, they will be recorded as gas costs under the PGA mechanism. At December 31, 2005, the Company had a net asset of $25.7 million related to the hedge of gas contracts to serve natural gas customers.

A hypothetical 10.0% decrease in the market prices of natural gas and electricity would decrease the fair value of qualifying cash flow hedges by $5.0 million and would have no effect for those contracts marked-to-market in earnings.

Energy Derivative Contracts Gain(loss) (Dollars in Millions)	Amounts
Fair value of contracts outstanding at December 31, 2005	$ 93.6
Contracts realized or otherwise settled during 2006	(34.1)
Changes in fair values of derivatives	(106.7)
Fair value of contracts outstanding at December 31, 2006	$ (47.2)

Source of Fair Value (Dollars in Millions)	Fair Value of Contracts with Settlement During Year 2007	2008-2009	2010-2011	2012 and Thereafter	Total Fair Value
Prices actively quoted	$(53.7)	$6.5	--	--	$(47.2)
Prices provided by other external sources	--	--	--	--	--
Prices based on models and other valuation methods	$(53.7)	$6.5	--	--	$(47.2)

Credit Risk

The Company is exposed to credit risk primarily through buying and selling electricity and gas to serve 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 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 December 31, 2006, approximately 99.0% of the counterparties comprising the sources of our energy portfolio are rated at least investment grade by the major rating agencies and 1.0% are either rated below investment grade or are not rated by rating agencies. The Company assesses credit risk internally for counterparties that are not rated.

Interest Rate Risk

The Company believes its interest rate risk primarily relates to the use of short-term debt instruments, variable-rate notes and leases and anticipated 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. The Company did not have any swap instruments outstanding on fixed rate debt as of December 31, 2006 or 2005, however from time to time the Company may enter into treasury lock or forward starting swap contracts to hedge interest rate exposure related to anticipated debt issuance. The carrying amounts and the fair values of the Company's debt instruments are:

	2006		2005	
(DOLLARS IN MILLIONS)	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE
Financial liabilities:				
Short-term debt	$ 328.0	$ 328.0	$ 41.0	$ 41.0
Short-term debt owed by PSE to Puget Energy	24.3	24.3	--	--
Long-term debt – fixed-rate[1]	2,733.4	2,823.3	2,264.4	2,416.6

1 *PSE's carrying value and fair value of fixed-rate long-term debt was the same as Puget Energy's debt in 2006 and 2005.*

In the second quarter 2006, the Company settled two forward starting swap contracts which originated in May 2005. The purpose of the forward starting swap contracts was to hedge a debt offering of $200.0 million that was completed on June 30, 2006. 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 of these instruments resulted in a gain of $13.9 million after-tax, which was recorded in other comprehensive income.

In the third quarter 2006, the Company entered into and settled two forward starting swap contracts. The purpose of the forward starting swap contracts was to hedge a debt offering of $300.0 million that was priced on September 13, 2006. 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 the third quarter 2006, the settlement of these instruments resulted in a loss of $0.4 million after tax, which was recorded 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 settled swaps contracts at December 31, 2006 was a net loss of $8.5 million after-tax and accumulated amortization. This compares to a loss of $22.4 million in other comprehensive income after-tax and accumulated amortization at December 31, 2005. 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 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

All other schedules have been omitted because of the absence of the conditions under which they are required, or because the information required is included in the financial statements or the notes thereto.

Financial statements of PSE's subsidiaries are not filed herewith inasmuch as the assets, revenues, earnings and earnings reinvested in the business of the subsidiaries are not material in relation to those of PSE.

REPORT OF MANAGEMENT AND STATEMENT OF RESPONSIBILITY

PUGET ENERGY, INC.
AND
PUGET SOUND ENERGY, INC.

Puget Energy, Inc. and Puget Sound Energy, Inc. (the Company) management assumes accountability for maintaining compliance with our established financial accounting policies and for reporting our results with objectivity and integrity. The Company believes it is essential for investors and other users of the consolidated financial statements to have confidence that the financial information we provide is timely, complete, relevant, and accurate. Management is also responsible to present fairly Puget Energy's and Puget Sound Energy's consolidated financial statements, prepared in accordance with generally accepted accounting principles.

Management, with oversight of the Board of Directors, established and maintains a strong ethical climate under the guidance of our Corporate Ethics and Compliance Program so that our affairs are conducted to high standards of proper personal and corporate conduct. Management also established an internal control system that provides reasonable assurance as to the integrity and accuracy of the consolidated financial statements. These policies and practices reflect corporate governance initiatives that are compliant with the corporate governance requirements of the Sarbanes-Oxley Act of 2002, including:

- Our Board has adopted clear corporate governance guidelines.
- With the exception of the Chairman of the Board, the Board members are independent of the Company and its management.
- All members of our key Board committees – the Audit Committee, the Compensation and Development Committee and the Governance and Public Affairs Committee – are independent of the Company and its management.
- The independent members of our Board meet regularly without the presence of Puget Energy and Puget Sound Energy management.
- The Charters of our Board committees clearly establish their respective roles and responsibilities.
- The Company has adopted a Corporate Ethics and Compliance Code with a hotline (through an independent third party) available to all employees, and our Audit Committee has procedures in place for the anonymous submission of employee complaints on accounting, internal accounting controls or auditing matters. The Compliance Program is led by the Chief Ethics and Compliance Officer of the Company.
- Our internal audit control function maintains critical oversight over the key areas of our business and financial processes and controls, and reports directly to our Board Audit Committee.

Management is confident that the internal control structure is operating effectively and will allow the Company to meet the requirements under Section 404 of the Sarbanes-Oxley Act of 2002.

PricewaterhouseCoopers LLP, our independent registered public accounting firm, reports directly to the Audit Committee of the Board of Directors. PricewaterhouseCoopers LLP's accompanying report on our consolidated financial statements is based on its audit conducted in accordance with auditing standards prescribed by the Public Company Accounting Oversight Board, including a review of our internal control structure for purposes of designing their audit procedures. Our independent registered accounting firm has reported on the effectiveness of our internal control over financial reporting as required under Section 404 of the Sarbanes-Oxley Act of 2002.

We are committed to improving shareholder value and accept our fiduciary oversight responsibilities. We are dedicated to ensuring that our high standards of financial accounting and reporting as well as our underlying system of internal controls are maintained. Our culture demands integrity and we have confidence in our processes, our internal controls, and our people, who are objective in their responsibilities and who operate under a high level of ethical standards.

/s/ Stephen P. Reynolds	/s/ Bertrand A. Valdman	/s/ James W. Eldredge
Stephen P. Reynolds *Chairman, President and Chief Executive Officer*	Bertrand A. Valdman *Senior Vice President Finance and Chief Financial Officer*	James W. Eldredge *Vice President, Corporate Secretary and Chief Accounting Officer*

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Puget Energy, Inc.:

We have completed integrated audits of Puget Energy Inc.'s consolidated financial statements and of its internal control over financial reporting as of December 31, 2006, in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements and financial statement schedules

In our opinion, the consolidated financial statements listed in the accompanying index, present fairly, in all material respects, the financial position of Puget Energy, Inc. and its subsidiaries at December 31, 2006 and December 31, 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedules listed in the accompanying index present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedules based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 4 to the consolidated financial statements, the Company changed the manner in which it accounts for conditional asset retirement obligations in 2005.

As discussed in Note 16 to the consolidated financial statements, the Company changed the manner in which it accounts for share-based compensation in 2006.

As discussed in Note 14 to the consolidated financial statements, the Company changed the manner in which it accounts for defined pension and other postretirement plans in 2006.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A, that the Company maintained effective internal control over financial reporting as of December 31, 2006 based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control - Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP
Seattle, WA
March 1, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of Puget Sound Energy, Inc.:

We have completed integrated audits of Puget Sound Energy Inc.'s consolidated financial statements and of its internal control over financial reporting as of December 31, 2006, in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements and financial statement schedule

In our opinion, the consolidated financial statements listed in the accompanying index, present fairly, in all material respects, the financial position of Puget Sound Energy, Inc. and its subsidiaries at December 31, 2006 and December 31, 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 4 to the consolidated financial statements, the Company changed the manner in which it accounts for conditional asset retirement obligations in 2005.

As discussed in Note 16 to the consolidated financial statements, the Company changed the manner in which it accounts for share-based compensation in 2006.

As discussed in Note 14 to the consolidated financial statements, the Company changed the manner in which it accounts for defined pension and other postretirement plans in 2006.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A, that the Company maintained effective internal control over financial reporting as of December 31, 2006 based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control - Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP
Seattle, WA
March 1, 2007

Puget Energy Consolidated Statements of

INCOME

(DOLLARS IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)

FOR YEARS ENDED DECEMBER 31	2006	2005	2004
Operating revenues:			
Electric	$ 1,777,745	$ 1,612,869	$ 1,423,034
Gas	1,120,118	952,515	769,306
Other	7,830	7,826	6,537
Total operating revenues	2,905,693	2,573,210	2,198,877
Operating expenses:			
Energy costs:			
Purchased electricity	917,801	860,422	723,567
Electric generation fuel	97,320	73,318	80,772
Residential exchange	(163,622)	(180,491)	(174,473)
Purchased gas	723,232	592,120	451,302
Unrealized (gain) loss on derivative instruments	71	472	(526)
Utility operations and maintenance	354,590	333,256	291,232
Other operations and maintenance	3,041	2,657	2,326
Depreciation and amortization	262,341	241,634	228,566
Conservation amortization	32,320	24,308	22,688
Taxes other than income taxes	255,712	233,742	208,989
Income taxes	96,271	88,609	76,756
Total operating expenses	2,579,077	2,270,047	1,911,199
Operating income	326,616	303,163	287,678
Other income (deductions):			
Other income	29,962	16,803	11,044
Charitable contributions	(15,000)	--	--
Other expense	(9,999)	(11,063)	(9,517)
Income taxes	3,784	2,569	2,835
Interest charges:			
AFUDC	15,874	9,493	5,420
Interest expense	(183,922)	(174,591)	(171,959)
Mandatorily redeemable securities interest expense	(91)	(91)	(91)
Net income from continuing operations	167,224	146,283	125,410
Income (loss) from discontinued segment (net of tax)	51,903	9,514	(70,388)
Net income before cumulative effect of accounting change	219,127	155,797	55,022
Cumulative effect of implementation of accounting change (net of tax)	89	(71)	--
Net income	$ 219,216	$ 155,726	$ 55,022
Common shares outstanding weighted average (in thousands)	115,999	102,570	99,470
Diluted shares outstanding weighted average (in thousands)	116,457	103,111	99,911
Basic earnings per common share before cumulative effect from accounting change	$ 1.44	$ 1.43	$ 1.26
Basic earnings per common share from discontinued operations	0.45	0.09	(0.71)
Cumulative effect from accounting change	--	--	--
Basic earnings per common share	$ 1.89	$ 1.52	$ 0.55
Diluted earnings per common share before cumulative effect from accounting change	$ 1.44	$ 1.42	$ 1.26
Diluted earnings per common share from discontinued operations	0.44	0.09	(0.71)
Cumulative effect from accounting change	--	--	--
Diluted earnings per common share	$ 1.88	$ 1.51	$ 0.55

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

Puget Energy Consolidated Balance Sheets

ASSETS

(DOLLARS IN THOUSANDS)

AT DECEMBER 31	2006	2005
Utility plant:		
Electric plant	$ 5,334,368	$ 4,802,363
Gas plant	2,146,048	1,991,456
Common plant	458,262	439,599
Less: Accumulated depreciation and amortization	(2,757,632)	(2,602,500)
Net utility plant	5,181,046	4,630,918
Other property and investments	151,462	157,321
Current assets:		
Cash	28,117	16,710
Restricted cash	839	1,047
Accounts receivable, net of allowance for doubtful accounts	253,613	294,509
Secured pledged accounts receivable	110,000	41,000
Unbilled revenues	202,492	160,207
Purchased gas adjustment receivable	39,822	67,335
Materials and supplies, at average cost	43,501	36,491
Fuel and gas inventory, at average cost	115,752	91,058
Unrealized gain on derivative instruments	16,826	75,037
Prepayments and other	9,228	7,596
Deferred income taxes	1,175	--
Current assets of discontinued operations	--	107,434
Total current assets	821,365	898,424
Other long-term assets:		
Restricted cash	3,814	--
Regulatory asset for deferred income taxes	115,304	129,693
Regulatory asset for PURPA buyout costs	167,941	191,170
Unrealized gain on derivative instruments	6,934	28,464
Power cost adjustment mechanism	6,357	18,380
Other	611,816	388,468
Long-term assets of discontinued operations	--	167,113
Total other long-term assets	912,166	923,288
Total assets	$ 7,066,039	$ 6,609,951

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

Puget Energy Consolidated Balance Sheets

CAPITALIZATION AND LIABILITIES

(DOLLARS IN THOUSANDS)

AT DECEMBER 31	2006	2005
Capitalization:		
(See Consolidated Statements of Capitalization)		
Common equity	$ 2,116,029	$ 2,027,047
Total shareholders' equity	2,116,029	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	4,764,028	4,450,046
Minority interest in discontinued operations	--	6,816
Current liabilities:		
Accounts payable	379,579	346,490
Short-term debt	328,055	41,000
Current maturities of long-term debt	125,000	81,000
Accrued expenses:		
Taxes	54,977	112,860
Salaries and wages	32,122	15,034
Interest	36,915	31,004
Unrealized loss on derivative instruments	70,596	9,772
Deferred income tax	--	10,968
Other	43,889	35,694
Current liabilities of discontinued operations	--	55,791
Total current liabilities	1,071,133	739,613
Long-term liabilities:		
Deferred income taxes	745,095	738,809
Unrealized loss on derivative instruments	415	--
Other deferred credits	485,368	513,023
Long-term liabilities of discontinued operations	--	161,644
Total long-term liabilities	1,230,878	1,413,476
Commitments and contingencies (Note 22)		
Total capitalization and liabilities	$ 7,066,039	$ 6,609,951

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

Puget Energy Consolidated Statements of

CAPITALIZATION

(DOLLARS IN THOUSANDS)

AT DECEMBER 31	2006	2005
Common equity:		
Common stock $0.01 par value, 250,000,000 shares authorized, 116,576,636 and 115,695,463 shares outstanding at December 31, 2006 and 2005	$ 1,166	$ 1,157
Additional paid-in capital	1,969,032	1,948,975
Earnings reinvested in the business	172,529	69,407
Accumulated other comprehensive income (loss) – net of tax	(26,698)	7,508
Total common equity	2,116,029	2,027,047
Preferred stock subject to mandatory redemption – cumulative – $100 par value: *		
4.84% series –150,000 shares authorized, 14,583 shares outstanding at December 31, 2006 and 2005	1,458	1,458
4.70% series –150,000 shares authorized, 4,311 shares outstanding at December 31, 2006 and 2005	431	431
Total 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:		
First mortgage bonds and senior notes	2,571,500	2,102,500
Pollution control revenue bonds:		
Revenue refunding 2003 series, due 2031	161,860	161,860
Other notes	--	--
Long-term debt due within one year	(125,000)	(81,000)
Total long-term debt excluding current maturities	2,608,360	2,183,360
Total capitalization	$ 4,764,028	$ 4,450,046

** Puget Energy has 50,000,000 shares authorized for $0.01 par value preferred stock. Puget Sound Energy has 13,000,000 shares authorized for $25 par value preferred stock and 3,000,000 shares authorized for $100 par value preferred stock. The preferred stock is available for issuance under mandatory and non-mandatory redemption provisions.*

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

Puget Energy Consolidated Statements of

COMMON SHAREHOLDERS' EQUITY

(DOLLARS IN THOUSANDS) FOR YEARS ENDED DECEMBER 31, 2006, 2005 & 2004	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income	Total Amount
Balance at December 31, 2003	99,074,070	$ 991	$1,603,901	$ 58,217	$ (8,063)	$1,655,046
Net income	--	--	--	55,022	--	55,022
Common stock dividend declared	--	--	--	(99,386)	--	(99,386)
Common stock issued:						
New issuance	5,195	--	68	--	--	68
Dividend reinvestment plan	681,491	7	15,170	--	--	15,177
Employee plans	107,612	1	2,617	--	--	2,618
Other comprehensive loss	--	--	--	--	(6,269)	(6,269)
Balance at December 31, 2004	99,868,368	$ 999	$1,621,756	$ 13,853	$ (14,332)	$1,622,276
Net income	--	--	--	155,726	--	155,726
Common stock dividend declared	--	--	--	(100,172)	--	(100,172)
Common stock issued:						
New issuance	15,009,991	150	309,744	--	--	309,894
Dividend reinvestment plan	656,267	6	14,545	--	--	14,551
Employee plans	160,837	2	2,930	--	--	2,932
Other comprehensive loss	--	--	--	--	21,840	21,840
Balance at December 31, 2005	115,695,463	$ 1,157	$1,948,975	$ 69,407	$ 7,508	$2,027,047
Net income	--	--	--	219,216	--	219,216
Common stock dividend declared	--	--	--	(116,094)	--	(116,094)
Common stock issued:						
Dividend reinvestment plan	614,548	6	13,481	--	--	13,487
Employee plans	266,625	3	6,576	--	--	6,579
Other comprehensive loss	--	--	--	--	(15,553)	(15,553)
Adjustment to initially apply SFAS No. 158, net of tax of $(12,420)	--	--	--	--	(18,653)	(18,653)
Balance at December 31, 2006	116,576,636	$ 1,166	$ 1,969,032	$ 172,529	$ (26,698)	$ 2,116,029

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

Puget Energy Consolidated Statements of

COMPREHENSIVE INCOME

(DOLLARS IN THOUSANDS)

FOR YEARS ENDED DECEMBER 31	2006	2005	2004
Net income	$ 219,216	$ 155,726	$ 55,022
Other comprehensive income (loss):			
Foreign currency translation adjustment, net of tax of $(176), $(49) and $148, respectively	(327)	(91)	275
Minimum pension liability adjustment, net of tax of $2,376, $0 and $0, respectively	2,873	925	157
Net unrealized gain (loss) on energy derivative instruments during the period, net of tax of $(17,669), $26,799 and $3,672, respectively	(32,813)	49,770	6,820
Reversal of net unrealized (gains) losses on energy derivative instruments settled during the period, net of tax of $(2,972), $(10,319) and $(5,610), respectively	(5,519)	(19,164)	(10,418)
Gain (loss) from settlement of financing cash flow hedge contracts, net of tax of $7,239, $(12,363) and $0, respectively	13,443	(22,960)	--
Amortization of financing cash flow hedge contracts to earnings, net of tax of $289, $245 and $0, respectively	537	455	--
Deferral of energy cash flow hedges related to power cost adjustment mechanism, net of tax of $3,367, $6,949 and $(1,671), respectively	6,253	12,905	(3,103)
Other comprehensive income (loss)	(15,553)	21,840	(6,269)
Comprehensive income	$ 203,663	$ 177,566	$ 48,753

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

Puget Energy Consolidated Statements of

CASH FLOWS

(DOLLARS IN THOUSANDS)

FOR YEARS ENDED DECEMBER 31	2006	2005	2004
Operating activities:			
Net income	$ 219,216	$ 155,726	$ 55,022
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	262,341	241,634	246,842
Deferred income taxes and tax credits – net	20,613	(56,852)	72,702
Power cost adjustment mechanism	12,023	(18,380)	3,605
Non cash return on regulatory assets	(12,438)	--	--
Amortization of gas pipeline capacity assignment	(10,632)	--	--
Gain on sale of InfrastruX	(29,765)	--	--
InfrastruX carrying value impairment adjustment	(7,269)	7,269	--
InfrastruX goodwill impairment	--	--	91,196
Net unrealized (gain) loss on derivative instruments	71	472	(526)
Other (including conservation amortization)	13,600	1,131	8,166
Cash collateral received from (returned to) energy suppliers	(22,020)	15,700	6,320
Gas pipeline capacity assignment	--	55,000	--
BPA prepaid transmission	--	(10,750)	--
Chelan PUD contract initiation	(89,000)	--	--
Storm damage deferred costs	(92,331)	--	--
Change in certain current assets and liabilities:			
Accounts receivable and unbilled revenue	(78,179)	(217,861)	2,218
Materials and supplies	(6,093)	(4,945)	(39,740)
Fuel and gas inventory	(24,694)	(25,163)	17,512
Prepayments and other	(4,319)	273	(8,159)
Purchased gas receivable / liability	27,513	(48,246)	(31,073)
Accounts payable	36,038	119,416	25,163
Taxes payable	(53,826)	38,047	247
Tenaska disallowance reserve	--	(3,156)	3,156
Accrued expenses and other	24,658	6,496	3,709
Net cash provided by operating activities	185,507	255,811	456,360
Investing activities:			
Construction and capital expenditures – excluding equity AFUDC	(749,516)	(583,594)	(409,403)
Energy efficiency expenditures	(33,865)	(24,428)	(24,852)
Restricted cash	(3,605)	586	905
Cash proceeds from property sales	936	24,291	1,315
Refundable cash received for customer construction projects	12,253	9,869	13,424
Cash proceeds from sale of InfrastruX, net of cash disposed	263,575	--	--
Other	5,500	5,906	432
Net cash used by investing activities	(504,722)	(567,370)	(418,179)
Financing activities:			
Change in short-term debt and leases – net	290,224	36,512	(5,596)
Dividends paid	(104,332)	(88,071)	(86,873)
Issuance of common stock	5,878	317,607	5,413
Issuance of bonds and notes	550,000	400,000	343,841
Net payments made to minority shareholders of InfrastruX	(10,451)	--	--
InfrastruX debt redeemed	(141,221)	--	--
Redemption of trust preferred stock	(200,000)	(42,500)	--
Redemption of bonds, notes and leases	(83,875)	(260,615)	(308,708)
Settlement of derivatives	20,682	(35,323)	--
Issuance costs and other	(2,467)	(12,928)	6,032
Net cash provided (used) by financing activities	324,438	314,682	(45,891)
Increase (decrease) in cash from net income	5,223	3,123	(7,710)
Cash at beginning of year	22,894	19,771	27,481
Cash at end of year	$ 28,117	$ 22,894	$ 19,771
Supplemental cash flow information:			
Cash payments for:			
Interest (net of debt AFUDC)	$ 167,789	$ 182,054	$ 182,419
Income taxes (net of refunds)	129,100	126,807	(1,232)

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

Puget Sound Energy Consolidated Statements of

INCOME

(DOLLARS IN THOUSANDS)

FOR YEARS ENDED DECEMBER 31	2006	2005	2004
Operating revenues:			
Electric	$ 1,777,745	$ 1,612,869	$ 1,423,034
Gas	1,120,118	952,515	769,306
Other	7,830	7,826	6,537
Total operating revenues	2,905,693	2,573,210	2,198,877
Operating expenses:			
Energy costs:			
Purchased electricity	917,801	860,422	723,567
Electric generation fuel	97,320	73,318	80,772
Residential exchange	(163,622)	(180,491)	(174,473)
Purchased gas	723,232	592,120	451,302
Unrealized (gain) loss on derivative instruments	71	472	(526)
Utility operations and maintenance	354,590	333,256	291,232
Other operations and maintenance	1,211	1,304	1,342
Depreciation and amortization	262,341	241,634	228,566
Conservation amortization	32,320	24,308	22,688
Taxes other than income taxes	255,712	233,742	208,989
Income taxes	97,227	89,629	77,177
Total operating expenses	2,578,203	2,269,714	1,910,636
Operating income	327,490	303,496	288,241
Other income (deductions):			
Other income	29,606	16,803	11,044
Other expense	(9,999)	(11,063)	(9,517)
Income taxes	(1,462)	2,569	2,835
Interest charges:			
AFUDC	15,874	9,493	5,420
Interest expense	(183,922)	(174,367)	(171,740)
Interest expense on Puget Energy note	(845)	--	--
Mandatorily redeemable securities interest expense	(91)	(91)	(91)
Net income before cumulative effect of accounting change	176,651	146,840	126,192
Cumulative effect of implementation of accounting change (net of tax)	89	(71)	--
Net income for common stock	$ 176,740	$ 146,769	$ 126,192

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

Puget Sound Energy Consolidated Balance Sheets

ASSETS

(DOLLARS IN THOUSANDS)

AT DECEMBER 31	2006	2005
Utility plant:		
Electric plant	$ 5,334,368	$ 4,802,363
Gas plant	2,146,048	1,991,456
Common plant	458,262	439,599
Less: Accumulated depreciation and amortization	(2,757,632)	(2,602,500)
Net utility plant	5,181,046	4,630,918
Other property and investments	151,462	157,321
Current assets:		
Cash	28,092	16,709
Restricted cash	839	1,047
Accounts receivable, net of allowance for doubtful accounts	253,613	299,938
Secured pledged accounts receivable	110,000	41,000
Unbilled revenues	202,492	160,207
Purchased gas adjustment receivable	39,822	67,335
Materials and supplies, at average cost	43,501	36,491
Fuel and gas inventory, at average cost	115,752	91,058
Unrealized gain on derivative instruments	16,826	75,037
Prepayments and other	8,659	7,023
Deferred income taxes	1,175	--
Total current assets	820,771	795,845
Other long-term assets:		
Regulatory asset for deferred income taxes	115,304	129,693
Regulatory asset for PURPA buyout costs	167,941	191,170
Unrealized gain on derivative instruments	6,934	28,464
Power cost adjustment mechanism	6,357	18,380
Other	611,598	388,009
Total other long-term assets	908,134	755,716
Total assets	$ 7,061,413	$ 6,339,800

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

Puget Sound Energy Consolidated Balance Sheets

CAPITALIZATION AND LIABILITIES

(DOLLARS IN THOUSANDS)

AT DECEMBER 31	2006	2005
Capitalization:		
(See Consolidated Statements of Capitalization):		
Common equity	$ 2,092,283	$ 1,986,621
Total shareholder's equity	2,092,283	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	4,740,282	4,409,620
Current liabilities:		
Accounts payable	379,494	346,490
Short-term debt	328,055	41,000
Short-term debt owed to Puget Energy	24,303	--
Current maturities of long-term debt	125,000	81,000
Accrued expenses:		
Taxes	55,365	111,900
Salaries and wages	31,591	15,034
Interest	37,031	31,004
Unrealized loss on derivative instruments	70,596	9,772
Deferred income taxes	--	10,968
Other	43,889	30,932
Total current liabilities	1,095,324	678,100
Long-term liabilities:		
Deferred income taxes	749,033	739,162
Unrealized loss on derivative instruments	415	--
Other deferred credits	476,359	512,918
Total long-term liabilities	1,225,807	1,252,080
Commitments and contingencies (Note 22)		
Total capitalization and liabilities	$ 7,061,413	$ 6,339,800

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

Puget Sound Energy Consolidated Statements of

CAPITALIZATION

(DOLLARS IN THOUSANDS)

AT DECEMBER 31	2006	2005
Common equity:		
Common stock ($10 stated value) – 150,000,000 shares authorized,		
85,903,791 shares outstanding	$ 859,038	$ 859,038
Additional paid-in capital	996,737	924,154
Earnings reinvested in the business	263,206	196,248
Accumulated other comprehensive income (loss) – net of tax	(26,698)	7,181
Total common equity	2,092,283	1,986,621
Preferred stock subject to mandatory redemption – cumulative -		
$100 par value:*		
4.84% series – 150,000 shares authorized,		
14,583 shares outstanding at December 31, 2006 and 2005	1,458	1,458
4.70% series – 150,000 shares authorized,		
4,311 shares outstanding at December 31, 2006 and 2005	431	431
Total 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:		
First mortgage bonds and senior notes	2,571,500	2,102,500
Pollution control revenue bonds:		
Revenue refunding 2003 series, due 2031	161,860	161,860
Long-term debt due within one year	(125,000)	(81,000)
Total long-term debt excluding current maturities	2,608,360	2,183,360
Total capitalization	$ 4,740,282	$ 4,409,620

**13,000,000 shares authorized for $25 par value preferred stock and 3,000,000 shares authorized for $100 par value preferred stock, both of which are available for issuance under mandatory and non-mandatory redemption provisions.*

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

Puget Sound Energy Consolidated Statements of

COMMON SHAREHOLDER'S EQUITY

(DOLLARS IN THOUSANDS) FOR YEARS ENDED DECEMBER 31, 2006, 2005 & 2004	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income	Total Amount
Balance at December 31, 2003	85,903,791	$859,038	$604,451	$100,186	$ (8,206)	$1,555,469
Net income	--	--	--	126,192	--	126,192
Common stock dividend declared	--	--	--	(87,700)	--	(87,700)
Investment received from Puget Energy	--	--	5,016	--	--	5,016
Other comprehensive loss	--	--	--	--	(6,544)	(6,544)
Balance at December 31, 2004	85,903,791	$859,038	$609,467	$138,678	$(14,750)	$1,592,433
Net income	--	--	--	146,769	--	146,769
Common stock dividend declared	--	--	--	(89,199)	--	(89,199)
Investment received from Puget Energy	--	--	314,687	--	--	314,687
Other comprehensive loss	--	--	--	--	21,931	21,931
Balance at December 31, 2005	85,903,791	$859,038	$924,154	$196,248	$ 7,181	$1,986,621
Net income	--	--	--	176,740	--	176,740
Common stock dividend declared	--	--	--	(109,782)	--	(109,782)
Investment received from Puget Energy	--	--	72,583	--	--	72,583
Other comprehensive income	--	--	--	--	(15,226)	(15,226)
Adjustment to initially apply SFAS No. 158, net of tax of $(12,420)	--	--	--	--	(18,653)	(18,653)
Balance at December 31, 2006	85,903,791	$859,038	$996,737	$263,206	$(26,698)	$2,092,283

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

Puget Sound Energy Consolidated Statements of

COMPREHENSIVE INCOME

(DOLLARS IN THOUSANDS) FOR YEARS ENDED DECEMBER 31	2006	2005	2004
Net income	$ 176,740	$ 146,769	$ 126,192
Other comprehensive income (loss):			
Minimum pension liability adjustment, net of tax of $2,376, $0 and $0, respectively	2,873	925	157
Net unrealized gains (losses) on energy derivative instruments during the period, net of tax of $(17,669), $26,799, and $3,672, respectively	(32,813)	49,770	6,820
Reversal of net unrealized (gains) losses on energy derivative instruments settled during the period, net of tax of $(2,972), $(10,319) and $(5,610), respectively	(5,519)	(19,164)	(10,418)
Gain (loss) from settlement of financing cash flow hedge contracts, net of tax of $7,239, $(12,363) and $0, respectively	13,443	(22,960)	--
Amortization of financing cash flow hedge contracts to earnings, net of tax of $289, $245 and $0, respectively	537	455	--
Deferral of energy cash flow hedges related to power cost adjustment mechanism, net of tax of $3,367, $6,949 and $(1,671), respectively	6,253	12,905	(3,103)
Other comprehensive income (loss)	(15,226)	21,931	(6,544)
Comprehensive income	$ 161,514	$ 168,700	$ 119,648

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

Puget Sound Energy Consolidated Statements of

CASH FLOWS

(DOLLARS IN THOUSANDS)

FOR YEARS ENDED DECEMBER 31	2006	2005	2004
Operating activities:			
Net income	$ 176,740	$ 146,769	$ 126,192
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	262,341	241,634	228,566
Deferred federal income taxes and tax credits – net	34,283	(57,597)	72,446
Power cost adjustment mechanism	12,023	(18,380)	3,605
Amortization of gas pipeline capacity assignment	(10,632)	--	--
Non cash return on regulatory assets	(12,438)	--	--
Net unrealized (gain) loss on derivative instruments	71	472	(526)
Other (including conservation amortization)	17,335	(4,803)	18,869
Cash collateral received from (returned to) energy suppliers	(22,020)	15,700	6,320
Gas pipeline capacity assignment	--	55,000	--
BPA prepaid transmission	--	(10,750)	--
Chelan PUD contract initiation	(89,000)	--	--
Storm damage deferred costs	(92,331)	--	--
Change in certain current assets and current liabilities:			
Accounts receivable and unbilled revenue	(64,961)	(221,960)	8,264
Materials and supplies	(7,010)	(4,808)	(37,884)
Fuel and gas inventory	(24,694)	(25,163)	17,512
Prepayments and other	(1,636)	(776)	38
Purchased gas receivable / liability	27,513	(48,246)	(31,073)
Accounts payable	33,004	116,743	23,282
Taxes payable	(56,535)	30,265	(707)
Tenaska disallowance reserve	--	(3,156)	3,156
Accrued expenses and other	30,588	(2,201)	(2,664)
Net cash provided by operating activities	212,641	208,743	435,396
Investing activities:			
Construction expenditures – excluding equity AFUDC	(745,239)	(568,381)	(393,891)
Energy efficiency expenditures	(33,865)	(24,428)	(24,852)
Restricted cash	208	586	905
Cash received from property sales	936	24,291	1,315
Refundable cash received for customer construction projects	12,253	9,869	13,424
Other	5,500	6,006	129
Net cash used by investing activities	(760,207)	(552,057)	(402,970)
Financing activities:			
Decrease in short-term debt – net	287,055	41,000	--
Dividends paid	(109,782)	(89,199)	(87,700)
Issuance of bonds and notes	550,000	400,000	200,000
Loan from Puget Energy	24,303	--	--
Redemption of trust preferred stock	(200,000)	(42,500)	--
Redemption of bonds and notes	(81,000)	(231,000)	(157,658)
Settlement of derivatives	20,682	(35,323)	--
Investment from Puget Energy	70,114	314,687	5,016
Issuance costs and other	(2,423)	(10,597)	6,093
Net cash provided (used) by financing activities	558,949	347,068	(34,249)
Increase (decrease) in cash from net income	11,383	3,754	(1,823)
Cash at beginning of year	16,709	12,955	14,778
Cash at end of year	$ 28,092	$ 16,709	$ 12,955
Supplemental cash flow information:			
Cash payments for:			
Interest (net of debt AFUDC)	$ 164,389	$ 172,986	$ 175,772
Income taxes (net of refunds)	123,100	126,591	(1,042)

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

NOTES

To Consolidated Financial Statements of Puget Energy and Puget Sound Energy

NOTE 1. *Summary of Significant Accounting Policies*

BASIS OF PRESENTATION

Puget Energy, Inc. (Puget Energy) is a holding company that owns Puget Sound Energy (PSE) and until May 7, 2006, a 90.9% interest in 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 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.

UTILITY PLANT

The cost of additions to utility plant, including renewals and betterments, are capitalized at original cost. Costs include indirect costs such as engineering, supervision, certain taxes, pension and other employee benefits, and an allowance for funds used during construction. Replacements of minor items of property and major maintenance are included in maintenance expense. The original cost of operating property is charged to accumulated depreciation and costs associated with removal of property, less salvage, are charged to the cost of removal regulatory liability when the property is retired and removed from service.

NON-UTILITY PROPERTY, PLANT AND EQUIPMENT

The costs of other property, plant and equipment are stated at historical cost. Expenditures for refurbishment and improvements that significantly add to productive capacity or extend useful life of an asset are capitalized. Replacement of minor items is expensed on a current basis. Gains and losses on assets sold or retired are reflected in earnings.

ACCOUNTING FOR THE IMPAIRMENT OF LONG-LIVED ASSETS

The Company evaluates impairment of long-lived assets in accordance with Statement of Financial Accounting Standards (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." SFAS No. 144 establishes accounting standards for determining if long-lived assets, including assets to be disposed of, are impaired and how losses, if any, should be recognized. The Company believes that the present value of the estimated future cash inflows from the use and eventual disposition of long-lived assets is sufficient to recover their carrying values.

DEPRECIATION AND AMORTIZATION

For financial statement purposes, the Company provides for depreciation and amortization on a straight-line basis. Amortization is comprised of software, small tools and office equipment. The depreciation of automobiles, trucks, power-operated equipment and tools is allocated to asset and expense accounts based on usage. The annual depreciation provision stated as a percent of average original cost of depreciable electric utility plant was 2.9% in 2006, 2005 and 2004; depreciable gas utility plant was 3.3% in 2006 and 3.4% in both 2005 and 2004; and depreciable common utility plant was 5.1% in 2006, 4.8% in 2005 and 4.6 % in 2004. Depreciation on other property, plant and equipment is calculated primarily on a straight-line basis over the useful lives of the assets. The cost of removal is collected from PSE's customers through depreciation expense and any excess is recorded as a regulatory liability.

CASH

All liquid investments with maturities of three months or less at the date of purchase are considered cash. The Company maintains cash deposits in excess of insured limits with certain financial institutions.

RESTRICTED CASH

Restricted cash represents cash to be used for specific purposes. The restricted cash balance was \$0.8 million and \$1.0 million at December 31, 2006 and 2005, respectively, which represents funds held by Puget Western, Inc., a PSE subsidiary, for a real estate development project. The long-term restricted cash balance was \$3.8 million which represents management's estimate of the aggregate fair value of the amount potentially payable under certain representations and warranties made by InfrastruX concerning its business.

MATERIAL AND SUPPLIES

Material and supplies consists primarily of materials and supplies used in the operation and maintenance of electric and gas distribution and transmission systems as well as spare parts for combustion turbines used for the generation of electricity. These items are recorded at lower of cost or market value using the weighted average cost method.

FUEL AND GAS INVENTORY

Fuel and gas inventory is used in the generation of electricity and for future sales to the Company's gas customers. Fuel inventory consists of coal, diesel, and natural gas used for generation. Gas inventory consists of natural gas and liquefied natural gas held in storage for future sales. These items are recorded at lower of cost or market value using the weighted average cost method.

REGULATORY ASSETS AND LIABILITIES

The Company accounts for its regulated operations in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 requires the Company to defer certain costs that would otherwise be charged to expense, if it were probable that future rates will permit recovery of such costs. Accounting under SFAS No. 71 is appropriate as long as rates are established by or subject to approval by independent third-party regulators; rates are designed to recover the specific enterprise's cost of service; and in view of demand for service, it is reasonable to assume that rates set at levels that will recover costs can be charged to and collected from customers. In most cases, the Company classifies regulatory assets and liabilities as long-term assets or liabilities. The exception is the purchased gas adjustment receivable which is a current asset.

The Company was allowed a return on the net regulatory assets and liabilities of 8.75% for electric rates beginning July 1, 2002 and gas rates beginning September 1, 2002 through March 3, 2005. Effective March 4, 2005 based on the 2004 general rate case, the Company is allowed a return on the net regulatory assets and liabilities of 8.4%, or 7.06% after-tax, for both electric and gas rates. The net regulatory assets and liabilities at December 31, 2006 and 2005 included the following:

(DOLLARS IN MILLIONS)	REMAINING AMORTIZATION PERIOD	2006	2005
PURPA electric energy supply contract buyout costs	1.5 to 5 years	$ 167.9	$ 191.2
Deferred income taxes	*	115.3	129.7
Storm damage costs – electric	**	101.1	15.0
Chelan PUD contract initiation	***	95.5	--
White River relicensing and other costs	****	69.1	66.1
PGA deferral of unrealized (gain) losses on derivative instruments	*	54.8	(25.7)
Purchased gas adjustment (PGA) receivable	*	39.8	67.3
Investment in Bonneville Exchange Power contract	10 years	37.0	40.6
Environmental remediation	****	36.3	34.2
Deferred AFUDC	30 years	33.3	32.0
Tree watch costs	8.3 years	19.8	24.2
Colstrip common property	17 years	12.5	13.2
Hopkins Ridge prepaid transmission upgrade	*****	8.9	10.8
Power cost adjustment (PCA) mechanism	*	6.4	18.4
Carrying costs on income tax payments	*	6.2	--
Various other regulatory assets	1 to 25 years	34.6	31.6
Total Regulatory Assets		$ 838.5	$ 648.6
Cost of removal	******	$ (127.1)	$ (125.3)
Deferred credit gas pipeline capacity	10.8 years	(44.4)	(55.0)
Deferred gains on property sales	3 years	(11.1)	(11.4)
Gas supply contract settlement	1.5 years	(5.7)	(9.5)
PCA deferral of unrealized gain on derivative instruments	*	--	(11.1)
Various other regulatory liabilities	1 to 21 years	(3.3)	(3.9)
Total Regulatory Liabilities		$ (191.6)	$ (216.2)
Net regulatory assets and liabilities		$ 646.9	$ 432.4

* *Amortization period varies depending on timing of underlying transactions.*
** *Amortization period for storm costs deferred in 2006 to be determined in a future Washington Commission rate proceeding.*
*** *Amortization period will start in 2011 for a 20 year period.*
**** *Amortization period to be determined in a future Washington Commission rate proceeding.*
***** *Amortization varies and based upon BPA tariff rate and FERC interest rate.*
****** *The balance is dependent upon the cost of removal of underlying assets and the life of utility plant.*

If the Company, at some point in the future, determines that all or a portion of the utility operations no longer meets the criteria for continued application of SFAS No. 71, the Company would be required to adopt the provisions of SFAS No. 101, "Regulated Enterprises - Accounting for the Discontinuation of Application of Financial Accounting Standards Board (FASB) Statement No. 71." Adoption of SFAS No. 101 would require the Company to write off the regulatory assets and liabilities related to those operations not meeting SFAS No. 71 requirements. Discontinuation of SFAS No. 71 could have a material impact on the Company's financial statements.

In accordance with guidance provided by the Securities and Exchange Commission (SEC), the Company reclassified from accumulated depreciation to a regulatory liability $127.1 million and $125.3 million in 2006 and 2005, respectively, for cost of removal for utility plant. These amounts are collected from PSE's customers through depreciation rates.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

The allowance for funds used during construction (AFUDC) represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period. The amount of AFUDC recorded in each accounting period varies depending principally upon the level of construction work in progress and the AFUDC rate used. AFUDC is capitalized as a part of the cost of utility plant and is credited to interest expense and as a non-cash item to other income.

Cash inflow related to AFUDC does not occur until these charges are reflected in rates.

The AFUDC rate allowed by the Washington Utilities and Transportation Commission (Washington Commission) for gas utility plant additions was 8.4% beginning March 4, 2005 and 8.76% for the period September 1, 2002 through March 3, 2005. The allowed AFUDC rate on electric utility plant was 8.4% beginning March 4, 2005 and 8.76% for the period July 1, 2002 through March 3, 2005. To the extent amounts calculated using this rate exceed the AFUDC calculated rate using the Federal Energy Regulatory Commission (FERC) formula, the Company capitalizes the excess as a deferred asset, crediting miscellaneous income. The amounts included in income were $2.7 million for 2006, $2.8 million for 2005 and $1.4 million for 2004. The deferred asset is being amortized over the average useful life of the Company's non-project electric utility plant.

CALIFORNIA RESERVE

PSE operates within the western wholesale market and has made sales into the California energy market. During 2003, FERC issued an order in the California Refund Proceeding adopting in part and modifying in part FERC's earlier findings by the Administrative Law Judge. The amount of the receivable, $21.2 million at December 31, 2006 is subject to the outcome of the ongoing litigation.

REVENUE RECOGNITION

Operating utility revenues are recorded on the basis of service rendered which includes estimated unbilled revenue. Sales to other utilities are recorded on a net revenue rendered basis in accordance with Emerging Issues Task Force of the Financial Accounting Standards Board (EITF) Issue No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB No. 133 and Not 'Held for Trading Purposes' as Defined in Issue No. 02-03." Non-utility subsidiaries recognize revenue when services are performed or upon the sale of assets.

PSE collected Washington State excise taxes (which are a component of general retail rates) and municipal taxes of $203.7 million, $178.0 million and $153.4 million for 2006, 2005 and 2004, 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.

ALLOWANCE FOR DOUBTFUL ACCOUNTS

An allowance for doubtful accounts is provided for energy customer accounts based upon a historical experience rate of write-offs of energy accounts receivable as compared to operating revenues. The allowance account is adjusted monthly for this experience rate. Other non-energy receivable balances are reserved for in the allowance account based on facts and circumstances surrounding the receivable, indicating some or all of the balance is uncollectible. Once exhaustive efforts have been made to collect these other receivables, the allowance account and corresponding receivable balance are written off.

Puget Energy's allowance for doubtful accounts at December 31, 2006 and 2005 was $2.8 million and $3.1 million, respectively.

SELF-INSURANCE

The Company currently has no insurance coverage for storm damage and environmental contamination that would occur in a current year on company-owned property. The Company is self-insured for a portion of the risk associated with comprehensive liability, workers' compensation claims and catastrophic property losses other than those which are storm related. The Washington Commission has approved the deferral of certain uninsured storm damage costs that exceed $7.0 million of qualifying storm damage costs for collection in future rates if the outage meets the Institute of Electrical and Electronics Engineers (IEEE) outage criteria for system average interruption duration index.

FEDERAL INCOME TAXES

Puget Energy and its subsidiaries file consolidated federal income tax returns. Income taxes are allocated to the subsidiaries on the basis of separate company computations of taxable income or loss. The Company provides for deferred taxes on certain assets and liabilities that are reported differently for income tax purposes than for financial reporting purposes, as required by SFAS No. 109, "Accounting for Income Taxes."

ENERGY EFFICIENCY

The Company offers programs designed to help new and existing customers use energy efficiently. The primary emphasis is to provide information and technical services to enable customers to make energy efficient choices with respect to building design, equipment and building systems, appliance purchases and operating practices.

Since May 1997, the Company has recovered electric energy efficiency expenditures through a tariff rider mechanism. The rider mechanism allows the Company to defer the efficiency expenditures and amortize them to expense as PSE concurrently collects the efficiency expenditures in rates over a one-year period. As a result of the rider mechanism, electric energy efficiency expenditures have no impact on earnings.

Since 1995, the Company has been authorized by the Washington Commission to defer gas energy efficiency expenditures and recover them through a tariff tracker mechanism. The tracker mechanism allows the Company to defer efficiency expenditures and recover them in rates over the subsequent year. The tracker mechanism also allows the Company to recover an allowance for funds used to conserve energy on any outstanding balance that is not being recovered in rates. As a result of the tracker mechanism, gas energy efficiency expenditures have no impact on earnings.

Energy efficiency programs reduce customer consumption of energy thus impacting energy margins. The impact of load reductions is adjusted in rates at each general rate case.

RATE ADJUSTMENT MECHANISMS

The Company has a power cost adjustment (PCA) mechanism that provides for a rate adjustment process 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. On October 20, 2005, the Washington Commission approved an amendment to the PCA mechanism changing the PCA period to a calendar year beginning January 1, 2007. The Washington Commission also made provision to reduce the graduated scale to half the annual excess power costs for the period July 1, 2006 through December 31, 2006 without a cap on excess power costs. 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 wheeling cost variability). The PCA mechanism apportions increases or decreases in power costs, on a graduated scale, between PSE and its customers. Any unrealized gains and losses from derivative instruments accounted for under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," are deferred in proportion to the cost-sharing arrangement under the PCA mechanism. On January 10, 2007, the Washington Commission approved the PCA mechanism with the same annual graduated scale but without a cap on excess power costs.

The graduated scale is as follows:

ANNUAL POWER COST VARIABILITY	JULY – DECEMBER 2006 POWER COST VARIABILITY[1]	CUSTOMERS' SHARE	COMPANY'S SHARE[2]
+/- $20 million	+/- $10 million	0%	100%
+/- $20 million - $40 million	+/- $10 - $20 million	50%	50%
+/- $40 million - $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 cost variation was capped at a cumulative $40.0 million plus 1% of the excess. Power cost variation after December 31, 2006 will be apportioned on an annual basis, based on the graduated scale without a cap.*

The differences between the actual cost of PSE's gas supplies and gas transportation contracts and costs currently allowed by the Washington Commission are deferred and recovered or repaid through the purchased gas adjustment (PGA) mechanism. 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 the PGA mechanism rates, including interest.

Natural Gas Off-System Sales and Capacity Release

The Company contracts for firm gas supplies and holds firm transportation and storage capacity sufficient to meet the expected peak winter demand for gas by its firm customers. Due to the variability in weather, winter peaking consumption of natural gas by most of its customers and other factors, the Company holds contractual rights to gas supplies, and transportation and storage capacity in excess of its average annual requirements to serve firm customers on its distribution system. For much of the year, there is excess capacity available for third-party gas sales, exchanges and capacity releases. The Company sells excess gas supplies, enters into gas supply exchanges with third parties outside of its distribution area and releases to third parties excess interstate gas pipeline capacity and gas storage rights on a short-term basis to mitigate the costs of firm transportation and storage capacity for its core gas customers. The proceeds from such activities, net of transactional costs, are accounted for as reductions in the cost of purchased gas and passed on to customers through the PGA mechanism, with no direct impact on net income. As a result, the Company nets the sales revenue and associated cost of sales for these transactions in purchased gas.

Accounting for Derivatives

The Company follows the provisions of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138 and SFAS No. 149 which requires that all contracts considered to be derivative instruments be recorded on the balance sheet at their fair value. Certain contracts that would otherwise be considered derivatives are exempt from SFAS No. 133 if they qualify for a normal purchase normal sale exception. The Company enters into both physical and financial contracts to manage its energy resource portfolio. The majority of these contracts qualify for the normal purchase normal sale exception for the purpose of serving retail load. However, those contracts that do not meet the normal purchase or normal sale exception are derivatives and, pursuant to SFAS No. 133, are reported at their fair value on the balance sheet. Changes in their fair value are reported in earnings unless they meet specific hedge accounting criteria, in which case changes in their fair market value are recorded in comprehensive income until the time the transaction that they are hedging is recorded in earnings. The Company designates a derivative instrument as a qualifying cash flow hedge if the change in the fair value of the derivative is highly effective in offsetting cash flows attributable to an asset, a liability or a forecasted transaction. To the extent that a portion of a derivative designated as a hedge is ineffective, changes in the fair value of the ineffective portion of that derivative are recognized currently in earnings. Changes in the market value of derivative transactions related to obtaining gas for the Company's retail gas business are deferred as regulatory assets or liabilities as a result of the Company's PGA mechanism and recorded in earnings as the transactions are executed.

Stock-Based 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.

Had the Company used 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) YEARS ENDED DECEMBER 31	2005	2004
Net income, as reported	$ 155,726	$ 55,022
Add: Total stock-based employee compensation expense included in net income, net of tax	1,652	2,457
Less: Total stock-based employee compensation expense per the fair value method of SFAS No. 123, net of tax	(2,195)	(2,603)
Pro forma net income	$ 155,183	$ 54,876
Earnings per common share:		
Basic as reported	$ 1.52	$ 0.55
Diluted as reported	$ 1.51	$ 0.55
Basic pro forma	$ 1.51	$ 0.55
Diluted pro forma	$ 1.51	$ 0.55

DEBT RELATED COSTS

Debt premiums, discounts, expenses and amounts received or incurred to settle hedges are amortized over the life of the related debt. The premiums and costs associated with reacquired debt are deferred and amortized over the life of the related new issuance, in accordance with ratemaking treatment.

EARNINGS PER COMMON SHARE (PUGET ENERGY ONLY)

Basic earnings per common share has been computed based on weighted average common shares outstanding of 115,999,000, 102,570,000 and 99,470,000 for 2006, 2005 and 2004, respectively. Diluted earnings per common share has been computed based on weighted average common shares outstanding of 116,457,000, 103,111,000 and 99,911,000 for 2006, 2005 and 2004, respectively, which includes the dilutive effect of securities related to employee stock-based compensation plans. In 2006, 46,000 shares related to stock options were excluded from the diluted weighted average common share calculation due to their antidilutive effect.

ACCOUNTS RECEIVABLE SECURITIZATION PROGRAM

On December 20, 2005, PSE entered into a five-year Receivable Sales Agreement with PSE Funding, Inc. (PSE Funding), a wholly owned, bankruptcy-remote subsidiary of PSE, formed for the purpose of purchasing customers' accounts receivable, both billed and unbilled. The results of PSE Funding are consolidated in the financial statements of PSE. The accounts receivable are sold at estimated fair value, based on the present value of discounted cash flows taking into account anticipated credit losses, the speed of payments and the discount rate commensurate with the uncertainty involved. The PSE Funding agreement replaces the Rainier securitization facility that was terminated on December 20, 2005. 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 $200.0 million or the borrowing base of eligible receivables which fluctuate with the seasonality of energy sales to customers. The PSE Funding receivables securitization facility expires in December 2010, and is terminable by PSE and PSE Funding upon notice to the banks. PSE Funding had $110.0 million of loans secured by accounts receivable pledged as collateral at December 31, 2006.

Rainier Receivables, Inc. (Rainier Receivables) was a wholly owned, bankruptcy-remote subsidiary of PSE formed in December 2002 for the purpose of purchasing customers' accounts receivable, both billed and unbilled, of PSE. Rainier Receivables and PSE had an agreement whereby Rainier Receivables would sell, on a revolving basis, up to $150.0 million of those eligible receivables. The agreement expired December 20, 2005. Rainier Receivables was obligated to pay fees that approximate the third-party purchaser's cost of issuing commercial paper equal in value to the interests in receivables sold.

CONSOLIDATED STATEMENTS OF CASH FLOWS

PSE funds cash dividends paid to the shareholders of Puget Energy. These funds are reflected in the Consolidated Statement of Cash Flows of Puget Energy as if Puget Energy received the cash from PSE and paid the dividends directly to the shareholders.

COMPREHENSIVE INCOME

Comprehensive income includes net income, foreign currency translations, changes in the minimum pension liability, unrealized gains and losses on derivative instruments, reversals of unrealized gains and losses on derivative instruments, settlements and amortization of cash flow hedge contracts and deferrals of cash flow hedges related to the power cost mechanism. The following table presents the Company's accumulated other comprehensive gain (loss) net of tax at December 31:

(DOLLARS IN THOUSANDS)	2006	2005
Unrealized gains (losses) on derivatives during the period	$ 9,584	$ 42,397
Reversal of unrealized (gains) losses on derivatives during the period	(4,691)	761
Adjustment to PCA	--	(6,253)
Settlement of cash flow hedge contract	13,447	67
Amortization of cash flow hedge contracts	(21,972)	(22,505)
Minimum pension liability adjustment	(4,413)	(7,286)
Adjustment to initially apply SFAS No. 158	(18,653)	--
Total PSE, net of tax	$ (26,698)	$ 7,181
Foreign currency translation adjustment	--	327
Total Puget Energy, net of tax	$ (26,698)	$ 7,508

NOTE 2. *New Accounting Pronouncements*

On September 29, 2006, FASB issued SFAS No. 158, "Employer's Accounting for Retired Benefit Pension and Other Postretirement Plans." See Note 14, "Retirement Benefits" for discussion of the new statement.

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.

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 requires the use of a two-step approach for recognizing and measuring tax positions taken or expected to be taken in a tax return. First, the tax position 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. Second, a tax position, that meets the recognition threshold, should be measured at the largest amount that has a greater than 50.0% likelihood of being sustained.

FIN 48 was effective for the Company as of January 1, 2007. The change in net assets as a result of adopting FIN 48 will be treated as a change in accounting method. The cumulative effect of the change will be recorded to retained earnings. Adjustments to regulatory accounts, if any, will be based on other applicable accounting standards. The Company is currently in the process of evaluating the provisions of FIN 48 to determine the potential impact, if any, the adoption will have on the Company's financial statements. The adoption of FIN 48 is not expected to have a material impact on the Company's retained earnings. Management's estimated impact of adoption is subject to change due to potential changes in interpretation of FIN 48 by the FASB or other regulatory bodies and the finalization of the Company's adoption efforts.

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 requires companies to disclose 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.

In December 2004, FASB issued SFAS No. 123R, "Share-Based Payment" (SFAS No. 123R), which revises SFAS No. 123, "Accounting For Stock-Based Compensation." SFAS No. 123R requires companies that issue share-based payment awards to employees for goods or services to recognize as compensation expense the fair value of the expected vested portion of the award as of the grant date over the vesting period of the award. Forfeitures that occur before the award vesting date will be adjusted from the total compensation expense, but once the award vests, no adjustment to compensation expense will be allowed for forfeitures or unexercised awards. In addition, SFAS No. 123R requires recognition of compensation expense of all existing outstanding awards that are not fully vested for their remaining vesting period as of the effective date that were not accounted for under a fair value method of accounting at the time of their award. 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.

In March 2005, FASB issued Interpretation No. 47 (FIN 47), which finalized a proposed interpretation of SFAS No. 143 titled, "Accounting for Conditional Asset Retirement Obligations." The interpretation addresses the issue of whether SFAS No. 143 requires an entity to recognize a liability for a legal obligation to perform asset retirement when the asset retirement activities are conditional on a future event, and if so, the timing and valuation of the recognition. The decision reached by FASB was that there are no instances where a law or regulation obligates an entity to perform retirement activities but then allows the entity to permanently avoid settling the obligation. FIN 47 was effective for the year ended December 15, 2005and was required to be accounted for as a cumulative effect of an accounting change. The Company adopted FIN 47 in the fourth quarter 2005, which resulted in the recognition of a cumulative effect for the asset retirement obligations amounting to $0.1 million after-tax.

On May 19, 2004, FASB issued FASB Staff Position No. 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," as the result of the new Medicare Prescription Drug Improvement and Modernization Act which was signed into law in December 2003. The law provides a subsidy for plan sponsors that provide prescription drug benefits to Medicare beneficiaries that are equivalent to the Medicare Part D plan. Based on new Medicare regulations issued in May 2005, the Company determined that it provides benefits at a higher level than provided under Medicare Part D, and therefore would qualify for federal tax subsidies.

NOTE 3. *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 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 December 31, 2006, long-term restricted cash in the amount of $3.8 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 related to those commitments. The obligation expires May 7, 2008. Should Tenaska make any such claims against Puget Energy, payment for the claims would 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 December 31, 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 guarantee 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 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 $9.5 million (net of taxes and minority interest) for 2005. Puget Energy's income from discontinued operations for 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."

	Twelve Months Ended December 31,		
(Dollars in Thousands)	2006[1]	2005	2004
Revenues	$ 138,573	$ 393,294	$ 369,936
Goodwill impairment	--	--	(91,196)
Operating expenses (including interest expense)	(128,605)	(356,934)	(357,990)
Pre-tax income	9,968	36,360	(79,250)
Income tax expense	(3,544)	(12,204)	1,793
Puget Energy carrying value adjustment of InfrastruX	7,269	(7,269)	--
Puget Energy cost of sale related to InfrastruX, net of tax	(937)	(5,195)	--
Puget Energy deferred tax basis adjustment of InfrastruX	9,966	--	--
Gain on sale, net of tax	29,765	--	--
Minority interest in income of discontinued operations	(584)	(2,178)	7,069
Income (loss) from discontinued operations	$ 51,903	$ 9,514	$ (70,388)

1 *Results for January 1, 2006 to May 7, 2006, the date InfrastruX was sold.*

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 $16.8 million ($10.8 million after-tax) and $6.7 million ($4.3 million after-tax) lower depreciation and amortization expense than otherwise would have been recorded as continuing operations for 2006 and 2005, respectively. Puget Energy recorded $0.2 million and $2.1 million of amortization expense related to the intangible assets of InfrastruX for 2005 and 2004, respectively.

Puget Energy's balance sheet at December 31, 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

NOTE 4. *Utility and Non-Utility Plant*

UTILITY PLANT (DOLLARS IN THOUSANDS) AT DECEMBER 31	ESTIMATED USEFUL LIFE (YEARS)	2006	2005
Electric, gas and common utility plant classified by prescribed accounts at original cost:			
Distribution plant	10-65	$ 4,887,304	$ 4,469,818
Production plant	20-100	1,694,569	1,326,383
Transmission plant	40-95	331,210	440,679
General plant	10-35	367,806	363,382
Whitehorn capital lease	10	23,004	--
Construction work in progress	NA	206,459	216,513
Intangible plant (including capitalized software)	3-29	297,939	288,509
Plant acquisition adjustment	21-34	77,871	77,871
Underground storage	50-80	24,389	23,880
Liquefied natural gas storage	14-50	14,217	12,339
Plant held for future use	NA	8,315	9,153
Other	NA	5,595	4,891
Less: accumulated provision for depreciation		(2,757,632)	(2,602,500)
Net utility plant		$ 5,181,046	$ 4,630,918

Jointly owned generating plants service costs are included in utility plant service cost. The following table indicates the Company's percentage ownership and the extent of the Company's investment in jointly owned generating plants in service at December 31, 2006. These amounts are also included in the Utility Plant table above.

			COMPANY'S SHARE	
JOINTLY OWNED GENERATING PLANTS (DOLLARS IN THOUSANDS)	ENERGY SOURCE (FUEL)	COMPANY'S OWNERSHIP SHARE	PLANT IN SERVICE AT COST	ACCUMULATED DEPRECIATION
Colstrip Units 1 & 2	Coal	50%	$ 228,480	$ (146,703)
Colstrip Units 3 & 4	Coal	25%	479,228	(272,003)
Colstrip Units 1 – 4 Common Facilities	Coal	*	252	(157)
Frederickson 1	Gas	49.85%	73,740	(6,281)

* *The Company's ownership is 50% for Colstrip Units 1 & 2 and 25% for Colstrip Units 3 & 4.*

Financing for a participant's ownership share in the projects is provided by such participant. The Company's share of related operating and maintenance expenses is included in corresponding accounts in the Consolidated Statements of Income.

NON-UTILITY PLANT (DOLLARS IN THOUSANDS) AT DECEMBER 31	ESTIMATED USEFUL LIFE (YEARS)	2006	2005
Non-utility plant	6-20	$ 2,948	$ 3,113
Less: accumulated provision for depreciation		(446)	(445)
Net non-utility plant		$ 2,502	$ 2,668

Non-utility plant is composed primarily of land and land rights that are not included in rate-based property. Non-utility plant and accumulated depreciation are included in "other" under "other property and investments" in the Puget Energy and PSE balance sheets.

The Company identified various asset retirement obligations under SFAS No. 143, "Accounting for Asset Retirement Obligations," upon initial adoption, and in 2005 identified additional asset retirement obligations to replace bare steel natural gas pipe and for the future removal of wind turbine generators. In March 2005, FASB issued FIN 47, "Accounting for Conditional Asset Retirement Obligations" (ARO), which provides guidance on when an asset retirement obligation that is conditional on a future event should be recognized. The Company adopted FIN 47 in the fourth quarter 2005 which resulted in the recognition of additional ARO. FIN 47 also requires that if an entity has any ARO for which no amount has been recognized, the existence of the ARO must be disclosed with the reasons why the liability has not been recognized.

Prior to the adoption of FIN 47, the Company recognized an obligation to: (1) dismantle two leased electric generation turbine units and deliver the turbines to the nearest railhead at the termination of the lease in 2009; (2) remove certain structures as a result of re-negotiations with the Department of Natural Resources of a now expired lease; (3) replace or line all cast iron pipes in its service territory by 2007 as a result of a 1992 Washington Commission order; (4) restore ash holding ponds at a jointly owned coal-fired electric generating facility in Montana; (5) replace all unprotected bare steel gas pipe in its service territory by 2015 as a result of a January 31, 2005 Washington Commission order; and (6) remove wind turbine generators and related equipment, improvements and fixtures at the termination of the related leases. The adoption of FIN 47 in the fourth quarter 2005 resulted in recognition of additional ARO to: (1) dispose of treated wood poles; (2) dispose of oil containing PCBs and the related equipment that held the oil; (3) remove asbestos in facilities that have been identified for remodeling or demolition; and (4) disconnect abandoned pipelines, purge the pipelines of gas and cut and cap their supplies of gas. In 2006, the Company recognized ARO for the decommissioning costs of the Frederickson facility at the end of its service life and costs related to wood poles, gas mains and contaminated oil in equipment placed in service in 2006.

The following table describes all changes to the Company's asset retirement obligation liability:

(DOLLARS IN THOUSANDS) AT DECEMBER 31	2006	2005
Asset retirement obligation at beginning of year	$ 28,274	$ 3,516
Liability recognized in transition	--	22,084
New asset retirement obligation liability recognized in the period	487	2,841
Liability settled in the period	(1,351)	(382)
Accretion expense	946	215
Asset retirement obligation at December 31	$ 28,356	$ 28,274

The Company has identified the following obligations which were not recognized at December 31, 2006: (1) a legal obligation under the Federal Dangerous Waste Regulations to dispose of asbestos-containing material in facilities that are not scheduled for remodeling, demolition or sale. The disposal cost related to these facilities could not be measured since the retirement date is indeterminable; therefore, the liability cannot be reasonably estimated currently; (2) an obligation under Washington state law to decommission the wells at the Jackson Prairie natural gas storage facility upon termination of the project. Since the project is expected to continue as long as the Northwest pipeline continues to operate, the liability cannot be reasonably estimated currently; (3) an obligation to pay its share of decommissioning costs at the end of the functional life of the major transmission lines. The major transmission lines are expected to be used indefinitely, therefore the liability cannot be reasonably estimated currently; (4) a legal obligation under the state of Washington environmental laws to remove and properly dispose of certain under and above ground storage fuel tanks. The disposal costs related to under and above ground storage tanks could not be measured since the retirement date is indeterminable; therefore the liability cannot be reasonably estimated currently; and (5) a potential legal obligation, arising (if at all) upon the expiration of an existing FERC hydropower license, were FERC to then order project decommissioning. Regardless, given the value of ongoing generation, flood control, and other benefits provided by these projects, PSE believes that the potential for decommissioning is both remote and cannot be reasonably estimated.

The pro forma asset retirement obligation liability balances as if SFAS No. 143, as interpreted by FIN 47, had been adopted on December 31, 2003 (rather than December 31, 2005) are as follows:

(DOLLARS IN THOUSANDS)	
Pro forma amounts of liability for asset retirement obligation at December 31, 2003	$ 25,281
Pro forma amounts of liability for asset retirement obligation at December 31, 2004	25,297

The pro forma income statement effect as if SFAS No. 143, as interpreted by FIN 47, had been adopted on December 31, 2003 (rather than December 31, 2005) is as follows:

(DOLLARS IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)	2005	2004
Net income, as reported	$ 155,726	$ 55,022
Add: SFAS No. 143 transition adjustment, net of tax	--	--
Add: FIN 47 transition adjustment, net of tax	71	--
Less: Pro forma accretion expense, net of tax	--	--
Pro forma net income	$ 155,797	$ 55,022
Earnings per share:		
Basic as reported	$ 1.52	$ 0.55
Diluted as reported	$ 1.51	$ 0.55
Basic pro forma	$ 1.52	$ 0.55
Diluted pro forma	$ 1.51	$ 0.55

NOTE 5. *Preferred Share Purchase Right*

On October 23, 2000, the Board of Directors declared a dividend of one preferred share purchase right (a Right) for each outstanding common share of Puget Energy. The dividend was paid on December 29, 2000 to shareholders of record on that date. The Rights will become exercisable only if a person or group acquires 10% or more of Puget Energy's outstanding common stock or announces a tender offer which, if consummated, would result in ownership by a person or group of 10% or more of the outstanding common stock. Each Right will entitle the holder to purchase from Puget Energy one one-hundredth of a share of preferred stock with economic terms similar to that of one share of Puget Energy's common stock at a purchase price of $65.0, subject to adjustments. The Rights expire on December 21, 2010, unless redeemed or exchanged earlier by Puget Energy.

NOTE 6. *Dividend Restrictions*

The payment of dividends on common stock is restricted by provisions of certain covenants applicable to preferred stock and long-term debt contained in the Company's Restated Articles of Incorporation and Mortgage Indentures. Under the most restrictive covenants of PSE, earnings reinvested in the business unrestricted as to payment of cash dividends were approximately $398.9 million at December 31, 2006. For the years 2006, 2005 and 2004, the aggregate dividends per share declared by Puget Energy were $1.00, $1.00, and $1.00, respectively.

PSE paid cash dividends on its common stock to Puget Energy of $109.8 million, $89.2 million and $87.7 million for 2006, 2005 and 2004, respectively.

NOTE 7. *Redeemable Securities*

The Company is required to deposit funds annually in a sinking fund sufficient to redeem the following number of shares of each series of preferred stock at $100 per share plus accrued dividends: 4.70% Series and 4.84% Series, 3,000 shares each. All previous sinking fund requirements have been satisfied. At December 31, 2006, there were 28,689 shares of the 4.70% Series and 12,192 shares of the 4.84% Series available for future sinking fund requirements. Upon involuntary liquidation, all preferred shares are entitled to their par value plus accrued dividends.

The preferred stock subject to mandatory redemption may also be redeemed by the Company at the following redemption prices per share plus accrued dividends: 4.70% Series, $101.00 and 4.84% Series, $102.00.

JUNIOR SUBORDINATED DEBENTURES OF THE CORPORATION PAYABLE TO A SUBSIDIARY TRUST HOLDING MANDATORILY REDEEMABLE PREFERRED SECURITIES

In 1997 and 2001, the Company formed Puget Sound Energy Capital Trust I and Puget Sound Energy Capital Trust II, respectively, for the sole purpose of issuing and selling common and preferred securities (Trust Securities). The proceeds from the sale of Trust Securities were used to purchase junior subordinated debentures (Debentures) from the Company. The Debentures are the sole assets of the Trusts and the Company owns all common securities of the Trusts.

The Debentures of Trust I and Trust II have an interest rate of 8.231% and 8.4%, respectively, and a stated maturity date of June 1, 2027 and June 30, 2041, respectively. The Trust Securities are subject to mandatory redemption at par on the stated maturity date of the Debentures. On June 30, 2006, PSE called all of PSE’s 8.4% Capital Trust Preferred Securities (classified as junior subordinated debentures of the corporation payable to a subsidiary trust holding mandatorily redeemable preferred securities on the balance sheets). The Capital Trust II Securities were redeemed at par and dividends relating to the preferred securities were paid and included in interest expense. The Capital Trust Preferred Securities were redeemed using the proceeds of senior notes issued at an interest rate of 6.724%.

NOTE 8. *Long-Term Debt*

FIRST MORTGAGE BONDS AND SENIOR NOTES
(DOLLARS IN THOUSANDS)
AT DECEMBER 31

SERIES	DUE	2006	2005	SERIES	DUE	2006	2005
6.58%	2006	$ --	$ 10,000	7.69%	2011	$ 260,000	$ 260,000
8.06%	2006	--	46,000	6.83%	2013	3,000	3,000
8.14%	2006	--	25,000	6.90%	2013	10,000	10,000
7.02%	2007	20,000	20,000	5.197%	2015	150,000	150,000
7.04%	2007	5,000	5,000	7.35%	2015	10,000	10,000
7.75%	2007	100,000	100,000	7.36%	2015	2,000	2,000
3.363%	2008	150,000	150,000	6.74%	2018	200,000	200,000
6.51%	2008	1,000	1,000	9.57%	2020	25,000	25,000
6.53%	2008	3,500	3,500	7.15%	2025	15,000	15,000
7.61%	2008	25,000	25,000	7.20%	2025	2,000	2,000
6.46%	2009	150,000	150,000	7.02%	2027	300,000	300,000
6.61%	2009	3,000	3,000	7.00%	2029	100,000	100,000
6.62%	2009	5,000	5,000	5.483%	2035	250,000	250,000
7.12%	2010	7,000	7,000	6.724%	2036	250,000	--
7.96%	2010	225,000	225,000	6.274%	2037	300,000	--
				Total		$ 2,571,500	$ 2,102,500

On March 16, 2006, Puget Energy and PSE filed a shelf registration statement with the SEC for the offering of common stock, senior notes, preferred stock, 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.

On June 30, 2006, PSE completed the issuance of $250.0 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 $200.0 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. On September 18, 2006, PSE completed the issuance of $300.0 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.

Substantially all utility properties owned by the Company are subject to the lien of the Company's electric and gas mortgage indentures. To issue additional first mortgage bonds under these indentures, PSE's earnings available for interest must be at least twice the annual interest charges on outstanding first mortgage bonds. At December 31, 2006, the earnings available for interest exceeded the required amount.

POLLUTION CONTROL BONDS

The Company has two series of Pollution Control Bonds outstanding. On February 19, 2003, the Board of Directors approved the refinancing of all Pollution Control Bonds series, which were issued in March 2003. Amounts outstanding were borrowed from the City of Forsyth, Montana (the City). The City obtained the funds from the sale of Customized Pollution Control Refunding Bonds issued to finance pollution control facilities at Colstrip Units 3 & 4.

Each series of bonds is collateralized by a pledge of PSE's first mortgage bonds, the terms of which match those of the Pollution Control Bonds. No payment is due with respect to the related series of first mortgage bonds so long as payment is made on the Pollution Control Bonds.

(DOLLARS IN THOUSANDS)
AT DECEMBER 31

SERIES	DUE	2006	2005
2003A Series – 5.00%	2031	$ 138,460	$ 138,460
2003B Series – 5.10%	2031	23,400	23,400
Total		$ 161,860	$ 161,860

LONG-TERM DEBT MATURITIES

The principal amounts of long-term debt maturities for the next five years and thereafter are as follows:

PUGET ENERGY AND PUGET SOUND ENERGY (DOLLARS IN THOUSANDS)	2007	2008	2009	2010	2011	THEREAFTER
Maturities of:						
Long-term debt	$ 125,000	$ 179,500	$ 158,000	$ 232,000	$ 260,000	$1,778,860

NOTE 9. *Related Party Transactions*

During 2006, Puget Energy established the Puget Sound Energy Foundation to aid qualifying nonprofit organizations that help support initiatives that back economic and environmental sustainability 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 Puget Sound Energy Foundation was established by Puget Energy as a nonprofit 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 London Interbank Offered Rate (LIBOR) rate plus a marginal rate. At December 31, 2006, the outstanding balance of the Note was $24.3 million and the interest rate was 5.54%. The outstanding balance and the related interest under the Note are eliminated by Puget Energy upon consolidation of PSE's financial statements.

NOTE 10. *Liquidity Facilities and Other Financing Arrangements*

At December 31, 2006, PSE had borrowing arrangements that included a five-year $500.0 million unsecured credit agreement with a group of banks and a five-year $200.0 million receivables securitization program. These arrangements provide PSE with the ability to borrow at different interest rate options and include variable fee levels. The bank credit agreement allows the Company to make floating rate advances at either LIBOR plus a spread or the banks' prime rate and contains "credit sensitive" pricing with various spreads associated with various credit rating levels. The bank credit agreement also allows for issuing standby letters of credit up to the entire amount of the credit agreement. In April 2006, PSE amended this credit agreement to extend the expiration date from April 2010 to April 2011.

On December 20, 2005, PSE entered into a five-year Receivable Sales Agreement with PSE Funding, a wholly owned subsidiary of PSE, replacing the Rainier Receivables securitization facility that was terminated 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 $200.0 million or the borrowing base of eligible receivables which fluctuate with the seasonality of energy sales to customers.

The PSE Funding receivables securitization facility expires in December 2010, and is terminable by PSE and PSE Funding upon notice to the banks. During 2006, PSE Funding borrowed a cumulative amount of $441.0 million secured by accounts receivable and had $110.0 million of loans secured by accounts receivable pledged as collateral at December 31, 2006. During 2005 and 2004, Rainier Receivables had sold a cumulative amount of $351.9 million and $600.2 million in accounts receivable, respectively. At December 31, 2005, PSE Funding had $41.0 million of loans secured by accounts receivable pledged as collateral.

In addition, PSE uses commercial paper to fund its short-term borrowing requirements. The following table presents the liquidity facilities and other financing arrangements at December 31, 2006 and 2005.

(DOLLARS IN THOUSANDS) AT DECEMBER 31	2006	2005
Committed financing arrangements:		
PSE line of credit [1]	$ 500,000	$ 500,000
PSE receivables securitization program [2]	200,000	200,000
Uncommitted financing agreements:		
PSE Unsecured Credit Agreement [3]	--	20,000
Puget Energy Demand Promissory Note [4]	30,000	--

1 *Provides liquidity support for PSE's outstanding commercial paper and letters of credit in the amount of $218.5 million in 2006 and $0.5 million in 2005, effectively reducing the available borrowing capacity under this credit line to $281.5 million and $499.5 million, respectively. There was $218.0 million of commercial paper outstanding at December 31, 2006 and no commercial paper outstanding at December 31, 2005.*

2 *Provides liquidity support for PSE's outstanding letters of credit and commercial paper. At December 31, 2006, PSE Funding had borrowed $110.0 million, leaving $90.0 million available to borrow under the receivables securitization program. At December 31, 2005, PSE Funding had $41.0 million of loans secured by accounts receivable pledged as collateral under the accounts receivable securitization program.*

3 *An uncommitted, unsecured credit agreement with a bank to borrow at terms that varied with market conditions and the length of the loan. The agreement was terminated and no longer in effect at December 31, 2006.*

4 *PSE has a revolving credit facility with Puget Energy in the form of a promissory note to borrow up to $30 million subject to approval by Puget Energy. At December 31, 2006, the outstanding balance on the note was $24.3 million. The outstanding balance and related interest are eliminated on Puget Energy's balance sheet upon consolidation.*

NOTE 11. *Estimated Fair Value of Financial Instruments*

The following table presents the carrying amounts and estimated fair values of the Company's financial instruments at December 31, 2006 and 2005.

(DOLLARS IN MILLIONS)	2006 Carrying Amount	2006 Fair Value	2005 Carrying Amount	2005 Fair Value
Financial assets:				
Cash	$ 28.1	$ 28.1	$ 16.7	$ 16.7
Restricted cash	0.8	0.8	1.0	1.0
Equity securities	2.0	2.0	2.0	2.0
Notes receivable and other	71.1	71.1	72.9	72.9
Energy derivatives	23.8	23.8	103.5	103.5
Long-term restricted cash	3.8	3.8	--	--
Financial liabilities:				
Short-term debt	$ 328.0	$ 328.0	$ 41.0	$ 41.0
Short-term debt owed by PSE to Puget Energy[1]	24.3	24.3	--	--
Preferred stock subject to mandatory redemption	1.9	1.3	1.9	1.4
Junior subordinated debentures of the corporation payable to a subsidiary trust holding mandatorily redeemable preferred securities	37.8	43.2	237.8	247.5
Long-term debt – fixed-rate[2]	2,733.4	2,823.3	2,264.4	2,416.6
Energy derivatives	71.0	71.0	9.8	9.8

1 *Short-term debt owed by PSE to Puget Energy is eliminated upon consolidation of Puget Energy.*

2 *PSE's carrying value and fair value of fixed-rate long-term debt was the same as Puget Energy's debt in 2006 and 2005.*

The carrying amount of equity securities is considered to be a reasonable estimate of fair value due to limited market pricing and based on the market value as reported by the fund manager. The fair value of outstanding bonds including current maturities is estimated based on quoted market prices. The fair value of the preferred stock subject to mandatory redemption is estimated based on dealer quotes. The fair value of the junior subordinated debentures of the corporation payable to a subsidiary trust holding mandatorily redeemable preferred securities is estimated based on dealer quotes. The carrying values of short-term debt and notes receivable are considered to be a reasonable estimate of fair value. The carrying amount of cash, which includes temporary investments with original maturities of three months or less, is also considered to be a reasonable estimate of fair value.

Derivative instruments have been used by the Company and are recorded at fair value. The Company has a policy that financial derivatives are to be used only to mitigate business risk.

NOTE 12. *Leases*

The Company leases buildings and assets under operating leases. In October 2006, the Company entered into an agreement to purchase certain assets at the Whitehorn generating site, which historically had been leased under an operating lease. The purchase agreement resulted in the classification of the Whitehorn lease as a capital lease. In accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," the amortization of the leased asset has been modified so that total interest and amortization is equal to the rental expense allowed for rate-making purposes. Interest accretion for 2006 was immaterial and capital lease amortization was $0.4 million for 2006. Certain leases contain purchase options and renewal and escalation provisions. Rent expense net of sublease receipts were:

(DOLLARS IN THOUSANDS) AT DECEMBER 31	
2006	$ 24,184
2005	17,145
2004	17,618

Payments received for the subleases of properties were approximately $0.1 million, $0.1 million and $0.1 million for 2006, 2005 and 2004, respectively.

Future minimum lease payments for non-cancelable leases net of sublease receipts are:

(DOLLARS IN THOUSANDS) AT DECEMBER 31	OPERATING	CAPITAL
2007	$ 13,834	$ 1,605
2008	13,976	1,605
2009	12,600	23,453
2010	11,237	--
2011	10,996	--
Thereafter	36,239	--
Total minimum lease payments	$ 98,882	$ 26,663

PSE leases a portion of its owned gas transmission pipeline infrastructure under a non-cancelable operating lease to a third party. The lease expires in 2009. Future minimum lease payments to be received by PSE under this lease are:

(DOLLARS IN THOUSANDS) AT DECEMBER 31	2007	2008	2009
Lease receipts	$ 1,182	$ 1,182	$ 886

NOTE 13. *Income Taxes*

The details of income taxes on continuing operations are as follows:

PUGET ENERGY (DOLLARS IN THOUSANDS)	2006	2005	2004
Charged to operating expense:			
Current:			
Federal	$ 62,122	$ 145,342	$ 5,506
State	979	1,936	(21)
Deferred - federal	33,673	(58,116)	71,864
Deferred investment tax credits	(503)	(553)	(593)
Total charged to operations	96,271	88,609	76,756
Charged to miscellaneous income:			
Current	(4,596)	(3,338)	(5,305)
Deferred	812	769	2,470
Total charged to miscellaneous income	(3,784)	(2,569)	(2,835)
Cumulative effect of accounting change	48	(38)	--
Total income taxes	$ 92,535	$ 86,002	$ 73,921

PUGET SOUND ENERGY (DOLLARS IN THOUSANDS)	2006	2005	2004
Charged to operating expense:			
Current:			
Federal	$ 62,825	$ 146,110	$ 5,825
State	979	1,936	(21)
Deferred - federal	33,926	(57,864)	71,966
Deferred investment tax credits	(503)	(553)	(593)
Total charged to operations	97,227	89,629	77,177
Charged to miscellaneous income:			
Current	650	(3,338)	(5,305)
Deferred	812	769	2,470
Total charged to miscellaneous income	1,462	(2,569)	(2,835)
Cumulative effect of accounting change	48	(38)	--
Total income taxes	$ 98,737	$ 87,022	$ 74,342

The following reconciliation compares pre-tax book income at the federal statutory rate of 35% to the actual income tax expense in the Consolidated Statements of Income:

PUGET ENERGY (DOLLARS IN THOUSANDS)	2006	2005	2004
Income taxes at the statutory rate	$ 90,947	$ 81,275	$ 69,766
Increase (decrease):			
Utility plant depreciation differences	9,307	9,534	10,723
AFUDC excluded from taxable income	(7,987)	(4,536)	(2,270)
Capitalized Interest	5,806	3,026	1,471
Production Tax Credit	(7,019)	(564)	--
Other - net	1,481	(2,733)	(5,769)
Total income taxes	$ 92,535	$ 86,002	$ 73,921
Effective tax rate	35.6%	37.0%	37.1%

PUGET SOUND ENERGY (DOLLARS IN THOUSANDS)	2006	2005	2004
Income taxes at the statutory rate	$ 96,417	$ 81,827	$ 70,187
Increase (decrease):			
Utility plant depreciation differences	9,307	9,534	10,723
AFUDC excluded from taxable income	(7,987)	(4,536)	(2,270)
Capitalized interest	5,806	3,026	1,471
Production Tax Credit	(7,019)	(564)	--
Other - net	2,213	(2,265)	(5,769)
Total income taxes	$ 98,737	$ 87,022	$ 74,342
Effective tax rate	35.8%	37.2%	37.1%

The Company's deferred tax liability at December 31, 2006, 2005 and 2004 is composed of amounts related to the following types of temporary differences:

PUGET ENERGY (DOLLARS IN THOUSANDS)	2006	2005
Utility plant and equipment	$ 736,368	$ 700,415
Capitalized overhead costs	--	33,166
Other deferred tax liabilities	96,486	97,197
Subtotal deferred tax liabilities	832,854	830,778
Contributions in aid of construction	(58,038)	(49,171)
Other deferred tax assets	(30,896)	(31,830)
Subtotal deferred tax assets	(88,934)	(81,001)
Total	$ 743,920	$ 749,777

The above amounts have been classified in the Consolidated Balance Sheets as follows:

PUGET ENERGY (DOLLARS IN THOUSANDS)	2006	2005
Current deferred taxes	$ (1,175)	$ 10,968
Non-current deferred taxes	745,095	738,809
Total	$ 743,920	$ 749,777

PUGET SOUND ENERGY (DOLLARS IN THOUSANDS)	2006	2005
Utility plant and equipment	$ 736,368	$ 700,415
Capitalized overhead costs	--	33,166
Other deferred tax liabilities	100,425	97,550
Subtotal deferred tax liabilities	836,793	831,131
Contributions in aid of construction	(58,038)	(49,171)
Other deferred tax assets	(30,897)	(31,830)
Subtotal deferred tax assets	(88,935)	(81,001)
Total	$ 747,858	$ 750,130

The above amounts have been classified in the Consolidated Balance Sheets as follows:

PUGET SOUND ENERGY (DOLLARS IN THOUSANDS)	2006	2005
Current deferred taxes	$ (1,175)	$ 10,968
Non-current deferred taxes	749,033	739,162
Total	$ 747,858	$ 750,130

The Company calculates its deferred tax assets and liabilities under SFAS No. 109, "Accounting for Income Taxes." SFAS No. 109 requires recording deferred tax balances, at the currently enacted tax rate, on assets and liabilities that are reported differently for income tax purposes than for financial reporting purposes. For ratemaking purposes, deferred taxes are not provided for certain temporary differences. Because of prior and expected future ratemaking treatment for temporary differences for which flow-through tax accounting has been utilized, PSE has established a regulatory asset for income taxes recoverable through future rates related to those differences. The balance of this asset was $115.3 million at December 31, 2006 and $129.7 million at December 31, 2005.

IRS Audit

As a matter of course, the Company's tax returns are routinely audited by federal, state and city tax authorities. In May of 2006, the IRS completed its examination of the company's 2001, 2002 and 2003 federal income tax returns. The Company is formally appealing two IRS audit adjustments. The first adjustment relates to the receivable balance due from the California Independent System Operator (CAISO). The IRS claims that the deduction was not valid for the 2003 tax year and would require repayment of approximately $14.5 million in tax. Management of Puget Energy believes the deduction is valid and intends to vigorously defend the deduction. Any potential tax payment (excluding interest) would have no impact on earnings, as it would be recognized as a deferred tax asset. If the Company is unsuccessful, a charge for interest expense would apply.

The second IRS audit adjustment relates to the company's accounting method with respect to capitalized internal labor and overheads. In its 2001 tax return, PSE claimed a deduction when it changed its tax accounting method with respect to capitalized internal labor and overheads. Under the new method, the Company could immediately deduct certain costs that it had previously capitalized. In the audit, the IRS disallowed the deduction. On August 2, 2005, the Internal Revenue Service and the Treasury Department issued Revenue Ruling 2005-53 and related Regulations. The Revenue Ruling and the Regulations required utility companies, including PSE, to adopt a less advantageous method of accounting and to repay the accumulated tax benefits. Through September 30, 2005, the Company claimed $66.3 million in accumulated tax benefits. PSE accounted for the accumulated tax benefits as temporary differences in determining its deferred income tax balances. Consequently, the repayment of the tax benefits did not impact earnings but did have a cash flow impact of $33.2 million in the fourth quarter 2005 and $33.1 million in 2006. As of December 31, 2006, the full tax benefit had been repaid. There is some uncertainty in the new guidance. PSE believes that the new Regulations required the Company to repay the accumulated tax benefits over the 2005 and 2006 tax years and that the tax deductions claimed on the Company's tax returns were appropriate based on the applicable statutes, Regulations, and case law in effect at the time. However, there is no assurance that PSE's appeal will prevail. If the Company is unsuccessful, a charge for interest expense would apply.

On October 19, 2005, PSE filed an accounting petition with the Washington Commission to defer the capital costs associated with repayment of the deferred tax. The Washington Commission had reduced PSE's ratebase by $72 million in its order of February 18, 2005. The accounting petition was approved by the Washington Commission on October 26, 2005, for deferral of additional capital costs beginning November 1, 2005 using PSE's allowed net of tax rate of return. The Washington Commission granted amortization of these deferred carrying costs over two years, beginning January 13, 2007.

Accounting for Uncertainty in Income Taxes

In July 2006, FASB issued 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 requires the use of a two-step approach for recognizing and measuring tax positions taken or expected to be taken in a tax return. First, a tax position 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. Second, a tax position, that meets the recognition threshold, should be measured at the largest amount that has a greater than 50% likelihood of being sustained.

FIN 48 was effective for the Company as of January 1, 2007. The change in net assets as a result of adopting FIN 48 will be treated as a change in accounting method. The cumulative effect of the change will be recorded to retained earnings. Adjustments to regulatory accounts, if any, will be based on other applicable accounting standards. The Company is currently in the process of evaluating the provisions of FIN 48 to determine the potential impact, if any, the adoption will have on the Company's financial statements. The adoption of FIN 48 is not expected to have a material impact on the Company's retained earnings. Management's estimated impact of adoption is subject to change due to potential changes in interpretation of FIN 48 by the FASB or other regulatory bodies and the finalization of the Company's adoption efforts.

NOTE 14. *Retirement Benefits*

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 is the year ended December 31, 2006 for the Company. SFAS No. 158 was 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.

The Company has a defined benefit pension plan with a cash balance feature covering substantially all PSE employees. Benefits are a function of age, salary and service. Puget Energy also maintains a non-qualified supplemental retirement plan for officers and certain director-level employees.

In addition to providing pension benefits, the Company provides certain health care and life insurance benefits for retired employees. These benefits are provided principally through an insurance company whose premiums are based on the benefits paid during the year.

	Pension Benefits		Other Benefits	
(DOLLARS IN THOUSANDS)	2006	2005	2006	2005
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 454,519	$ 438,635	$ 26,251	$ 31,094
Service cost	12,554	11,549	361	305
Interest cost	24,668	23,855	1,522	1,409
Amendment[1]	--	--	--	359
Actuarial loss (gain)	4,774	3,236	1,261	(4,796)
Benefits paid	(27,505)	(22,756)	(2,189)	(2,120)
Benefit obligation at end of year	$ 469,010	$ 454,519	$ 27,206	$ 26,251

[1] *The Company has an amendment related to changes in eligibility criteria.*

	Pension Benefits		Other Benefits	
(DOLLARS IN THOUSANDS)	2006	2005	2006	2005
Change in plan assets:				
Fair value of plan assets at beginning of year	$ 481,444	$ 458,980	$ 15,668	$ 15,959
Actual return on plan assets	75,278	43,119	1,699	696
Employer contribution	3,391	2,101	669	1,133
Benefits paid	(27,505)	(22,756)	(2,189)	(2,120)
Fair value of plan assets at end of year	$ 532,608	$ 481,444	$ 15,847	$ 15,668
Funded status at end of year	$ 63,598	$ 26,925	$ (11,359)	$ (10,583)

(DOLLARS IN THOUSANDS)	Pension Benefits 2006	2005	Other Benefits 2006	2005
Amounts recognized in Statement of Financial Position consist of:				
Noncurrent assets	$ 101,708	$ --	$ --	$ --
Current liabilities	(4,533)	--	(50)	--
Noncurrent liabilities	(33,577)	--	(11,309)	--
Total	$ 63,598	$ --	$ (11,359)	$ --
Amounts recognized in Accumulated Other Comprehensive Income consist of:				
Net loss (gain)	$ 29,984	$ --	$ (6,341)	$ --
Prior service cost / (credit)	6,452	--	2,862	--
Transition obligations / (assets)	--	--	2,529	--
Total	$ 36,436	$ --	$ (950)	$ --

The projected benefit obligation, fair value of plan assets and the funded status, measured as the difference between the fair value of plan assets and the benefit obligation for the non-qualified pension plan were $38.1 million, none, and $(38.1) million, respectively, as of December 31, 2006. For the qualified pension plan the projected benefit obligation, fair value of plan assets and the funded status were $430.9 million, $532.6 million and $101.7 million, respectively, as of December 31, 2006.

The projected benefit obligation, fair value of plan assets and the funded status of plan assets for the non-qualified pension plan, were $39.2 million, none, and $(39.2) million, respectively, as of December 31, 2005. For the qualified pension plan, the projected benefit obligation, fair value of plan assets, and the funded status were $415.3 million, $481.4 million and $66.1 million, respectively, as of December 31, 2005.

(DOLLARS IN THOUSANDS)	PENSION BENEFITS 2006	2005	2004	OTHER BENEFITS 2006	2005	2004
Components of net periodic benefit cost:						
Service cost	$ 12,553	$ 11,549	$ 10,249	$ 361	$ 305	$ 283
Interest cost	24,667	23,855	24,016	1,522	1,409	1,736
Expected return on plan assets	(37,572)	(37,928)	(39,106)	(871)	(878)	(858)
Amortization of prior service cost	2,341	2,867	3,033	534	466	465
Amortization of net loss (gain)	5,230	3,354	1,221	(273)	(612)	(332)
Amortization of transition (asset) obligation	--	(163)	(1,104)	418	418	418
Net periodic benefit cost (income)	$ 7,219	$ 3,534	$ (1,691)	$ 1,691	$ 1,108	$ 1,712

(DOLLARS IN THOUSANDS)	PENSION BENEFITS 2006	2005	OTHER BENEFITS 2006	2005
Other changes (pre-tax) in plan assets and benefit obligations recognized in other comprehensive income:				
(Increase) / decrease during year under SFAS 132R	$ (497)	$ --	$ --	$ --
(Increase) / decrease due to adoption of SFAS 158	29,647	--	(950)	--
Total change in other comprehensive income for year	$ 29,150	$ --	$ (950)	$ --

(DOLLARS IN THOUSANDS)	BEFORE APPLICATION OF STATEMENT 158 PENSION PLAN	OTHER BENEFITS	ADJUSTMENTS PENSION PLAN	OTHER BENEFITS	AFTER APPLICATION OF STATEMENT 158 PENSION PLAN	OTHER BENEFITS
Transition Adjustments for Statement of Financial Position:						
Prepaid benefit cost	$ 122,274	$ --	$ (122,274)	$ --	$ --	$ --
Accrued benefit (liability)	(33,056)	(12,309)	33,056	12,309	--	--
Intangible asset	4,027	--	(4,027)	--	--	--
Accumulated other comprehensive income, (pre-tax)	6,789	--	29,647	(950)	36,436	(950)
Noncurrent asset	--	--	101,708	--	101,708	--
Current liability	--	--	(4,533)	(50)	(4,533)	(50)
Noncurrent liability	--	--	(33,577)	(11,309)	(33,577)	(11,309)
Total	$ 100,034	$ (12,309)	$ --	$ --	$100,034	$ (12,309)

The estimated net loss (gain) and prior service cost (credit) for the pension plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2007 are $4.7 million and $2.0 million, respectively. The estimated net loss (gain), prior service cost (credit) and transition obligation (asset) for the other postretirement plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2007 are $(0.2) million, $0.5 million and $0.4 million.

In accounting for pension and other benefit obligations and costs under the plans, the following weighted average actuarial assumptions were used:

	PENSION BENEFITS			OTHER BENEFITS		
BENEFIT OBLIGATION ASSUMPTIONS	2006	2005	2004	2006	2005	2004
Discount rate	5.80%	5.60%	5.60%	5.80%	5.60%	5.60%
Rate of compensation increase	4.50%	4.50%	4.50%	--	--	--
Medical trend rate	--	--	--	10.00%	11.00%	12.00%

	PENSION BENEFITS			OTHER BENEFITS		
BENEFIT COST ASSUMPTIONS	2006	2005	2004	2006	2005	2004
Discount Rate	5.60%	5.60%	6.25%	5.60%	5.60%	6.25%
Return on plan assets	8.25%	8.25%	8.25%	4.3-8%	4.3-8%	4.3-8.25%
Rate of compensation increase	4.50%	4.50%	4.50%	--	--	--
Medical trend rate	--	--	--	11.00%	12.00%	9.00%

The assumed medical inflation rate used to determine benefit obligations is 10.0% in 2007 grading down to 6.0% in 2011. A 1% change in the assumed medical inflation rate would have the following effects:

	2006		2005	
(DOLLARS IN THOUSANDS)	1% INCREASE	1% DECREASE	1% INCREASE	1% DECREASE
Effect on post-retirement benefit obligation	$ 752	$ (666)	$ 437	$ (378)
Effect on service and interest cost components	42	(38)	30	(27)

The Company has selected the expected return on plan assets based on a historical analysis of rates of return and the Company's investment mix, market conditions, inflation and other factors. The expected rate of return is reviewed annually based on these factors and adjusted accordingly. The Company's accounting policy for calculating the market-related value of assets for the Company's retirement plan is as follows. The market-related value of assets is based on a five-year smoothing of asset gains/losses measured from the expected return on market-related assets. This is a calculated value that recognizes changes in fair value in a systematic and rational manner over five years. The same manner of calculating market-related value is used for all classes of assets, and is applied consistently from year to year.

The discount rate was determined by using market interest rate data and the weighted average discount rate from Citigroup Pension Liability Index Curve. The Company also takes into account in determining the discount rate the expected changes in market interest rates and anticipated changes in the duration of the plan liabilities.

The aggregate expected contributions by the Company to fund the pension and other benefit plans for the year ending December 31, 2007 are $4.5 million and $0.3 million, respectively. The full amount of the pension funding for 2007 is for the Company's non-qualified supplemental retirement plan.

The fair value of the plan assets of the pension benefits and other benefits are invested as follows at December 31:

	2006		2005	
	PENSION BENEFITS	OTHER BENEFITS	PENSION BENEFITS	OTHER BENEFITS
Short-term investments and cash	2.7%	--	2.4%	1.9%
Equity securities	62.9%	--	62.3%	--
Fixed income securities	14.8%	13.4%	15.3%	17.3%
Mutual funds (equity and fixed income)	19.6%	86.6%	20.0%	80.8%

The expected total benefits to be paid under both plans for the next five years and the aggregate total to be paid for the five years thereafter are as follows:

(DOLLARS IN THOUSANDS)	2007	2008	2009	2010	2011	2012-2016
Total benefits	$33,797	$31,578	$32,817	$35,350	$35,028	$197,315

The Company has a Retirement Committee that establishes investment policies, objectives and strategies designed to balance expected return with a prudent level of risk. All changes to the investment policies are reviewed and approved by the Retirement Committee prior to being implemented.

The Retirement Committee contracts with investment managers who have historically achieved above-median long-term investment performance within the risk and asset allocation limits that have been established. Interim evaluations are routinely performed with the assistance of an outside investment consultant. To obtain the desired return needed to fund the pension benefit plans, the Retirement Committee has established investment allocation percentages by asset classes as follows:

	ALLOCATION		
ASSET CLASS	MINIMUM	TARGET	MAXIMUM
Short-term investments and cash	--	--	5%
Equity securities	40%	70%	95%
Fixed-income securities	15%	30%	55%
Real estate	--	--	10%

On May 19, 2004, FASB issued FASB Staff Position No. 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" as the result of the new Medicare Prescription Drug Improvement and Modernization Act which was signed into law in December 2003. The law provides a subsidy for plan sponsors that provide prescription drug benefits to Medicare beneficiaries that are equivalent to the Medicare Part D plan. Based on new Medicare regulations issued in May 2005, the Company determined that it provides benefits at a higher level than provided under Medicare Part D, and therefore would qualify for federal tax subsidies.

NOTE 15. *Employee Investment Plans*

The Company has qualified Employee Investment Plans under which employee salary deferrals and after-tax contributions are used to purchase several different investment fund options.

The Company's contributions to the Employee Investment Plans were $7.9 million, $6.9 million and $6.3 million for the years 2006, 2005 and 2004, respectively. The Employee Investment Plan eligibility requirements are set forth in the plan documents.

NOTE 16. *Stock-based Compensation Plans*

Prior to 2006, the Company had various stock-based compensation plans which were accounted for according to 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 at December 31, 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 at December 31, 2006 under SFAS No. 123R as compared to earlier methods.

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 50.0% 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 in 2003 vest over a four year period. 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 $(1.6) million, $1.0 million and $2.5 million for 2006, 2005 and 2004, respectively. As of December 31, 2006, $3.0 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 1.7 years. A summary of the performance shares activity is as follows:

Performance shares grants outstanding:	2006
Beginning of Year	907,983
Granted	152,254
Vested	(40,851)
Cancelled*	(572,393)
Forfeited	(68,782)
End of Year	378,211

* *Performance shares at December 31, 2006 were cancelled because performance modifiers were not achieved.*

During 2006 there were four active grant cycles. The two remaining grants outstanding at December 31, 2006 were as follows:

	Performance Share Grants Cycles as of December 31, 2006	
Performance share grants cycle:	2006	2005
Number of awards granted	152,254	251,660
Estimated forfeiture rate	10.10%	11.80%
Estimated forfeited awards	15,378	29,696
Weighted average fair value (per share)	$ 24.77	$ 21.20

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. 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. A small percentage of the performance share grants are classified as equity awards because the employee does not have the option to receive the payment of these awards in cash. The equity portion is valued at the closing price of the Company's common stock on the grant date.

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 December 31, 2006, with 270,000 options exercisable. At December 31, 2005, 202,500 options were exercisable. The fair value of the options at the grant date was $3.33 per share. Compensation expense related to stock options was immaterial to the financial statements for 2006. The total fair value of stock options vested during 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. Under the 2006 grant, the shares vest 15.0% on January 1, 2007, 25.0% vest on January 1, 2008, and the remaining 60.0% 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 December 31, 2006, there were 205,656 total shares of nonvested restricted stock and the weighted average grant date fair value of these shares was $22.02. There was $1.7 million of total unrecognized compensation cost related to nonvested restricted stock at December 31, 2006. That cost is expected to be recognized over a weighted-average period of 1.6 years. Compensation expense related to the restricted shares was $2.0 million and $0.7 million for 2006 and 2005, respectively. Dividends are paid on all outstanding shares of restricted stock and are accounted for as a Puget Energy common stock dividend, not as compensation expense. The weighted average grant date fair value for all outstanding shares of restricted stock granted in 2006 and 2005 was $21.32 and $21.86, respectively. During 2006, 15,333 shares of restricted stock vested and 2,566 shares of restricted stock were forfeited. No restricted stock was forfeited during 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 December 31, 2006, there were 10,000 total shares of nonvested restricted stock units and the weighted average fair value of these units was $25.36. There was $0.1 million of total unrecognized compensation cost related to nonvested restricted stock units as of December 31, 2006. That cost is expected to be recognized over a weighted-average period of 1.3 years. There were no restricted stock units granted or forfeited during 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 $0.1 million for 2006 and 2005. 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 15.0% per year for the first six years and the remaining 10.0% in the seventh year. 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.

At December 31, 2006, there were 6,268 total shares of nonvested retirement equivalent stock units and the weighted average grant date fair value of these units was $22.60. There was $0.1 million unrecognized compensation cost related to nonvested retirement equivalent stock units as of December 31, 2006. That cost is expected to be recognized over a weighted-average period of 1.4 years. 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 $0.2 million and $0.1 million in 2006 and 2005, respectively. During 2006, 8,043 retirement equivalent stock units vested. 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 85.0% of the lower of the stock's fair market price at the beginning or the end of the six-month period. A maximum of 500,000 shares may be sold to employees under the plan through May 2007. At December 31, 2006, 82,318 shares could still be sold to employees under the plan. In 2006 and 2005, 66,496 and 58,132 shares were issued for the ESPP, respectively. Under 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. 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 100.0% 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 $0.5 million and $0.4 million in 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 December 31, 2006, 34,166 shares had been issued or purchased for the director stock plan and 92,807 deferred, for a total of 126,973 shares. As of December 31, 2005, the number of shares that had been purchased for the director stock plan was 25,221 and deferred was 77,741, for a total of 102,962 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 are 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.

NOTE 17. *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. Generally, NPNS applies if PSE deems the counterparty creditworthy, 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 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 December 31, 2006, the Company was subject to a range of netting provisions, including both stand alone agreements and the provisions associated with the Western Systems Power Pool agreement, of which many energy suppliers in the western United States are a part.

During the twelve months ended December 31, 2006, the Company recorded a decrease in earnings for the change in the market value of derivative instruments not meeting NPNS or cash flow hedge criteria of approximately $0.1 million compared to a decrease in earnings of approximately $0.5 million and an increase of $0.5 million for the twelve months ended December 31, 2005 and December 31, 2004 respectively.

At December 31, 2006, the Company had a net unrealized gain recorded in other comprehensive income of $4.9 million after-tax related to energy contracts which meet the criteria for designation as cash flow hedges under SFAS No. 133. The amount of cash flow hedges associated with these energy contracts that will reverse and be settled into the income statement during 2007 is approximately $0.7 million. At December 31, 2006, PSE had a short-term asset of $9.2 million and a long-term asset of $6.8 million as well as short-term liability of $8.0 million and a long-term liability of $0.4 million related to energy contracts designated as cash flow hedges that represent forward financial purchases of gas supply for electric generation from PSE-owned electric plants in future periods. If it is determined that it is uneconomical to run the plants in the future period, the hedging relationship is ended and the cash flow hedge is de-designated and any unrealized gains and losses are recorded in the income statement. Gains and losses when these de-designated cash flow hedges are settled are recognized in energy costs and are included as part of the PCA mechanism. At December 31, 2005, the Company had an unrealized gain recorded in other comprehensive income of $43.2 million (net of tax), before SFAS No. 71 deferrals of $6.3 million, related to energy contracts which met the criteria for designation as cash flow hedges under SFAS No. 133. This was mainly the result of higher forward market prices for natural gas and electricity at December 31, 2005 compared to December 31, 2006.

At December 31, 2006, the Company also had a short-term asset of $6.8 million and a short-term liability of approximately $61.6 million and a long-term asset of $0.1 million related to the 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 hedges are realized in future periods, they will be recorded as gas costs under the PGA mechanism. At December 31, 2005, the company had a net asset of $25.7 million related to the hedge of gas contracts to serve natural gas customers.

In the second quarter 2006, the Company settled two forward starting swap contracts originating in May 2005. The purpose of the forward starting swap contracts was to hedge a debt offering of $200.0 million that was completed on June 30, 2006. 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 of these instruments resulted in a gain of $13.9 million after-tax, which was recorded in other comprehensive income.

In the third quarter 2006, the Company settled two forward starting swap contracts originating in September 2006. The purpose of the forward starting swap contracts was to hedge a $300.0 million debt offering that was priced on September 13, 2006. 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 the third quarter of 2006, the settlement of these instruments resulted in a loss of $0.4 million after-tax, which was recorded 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 swaps contracts at December 31, 2006 was a loss of $8.5 million after-tax and accumulated amortization. This compares to a loss of $22.4 million in other comprehensive income after-tax and accumulated amortization at December 31, 2005 related to forward starting swaps and previously settled treasury lock contracts.

NOTE 18. *Colstrip Matters*

In May 2003, approximately 50 plaintiffs brought an action against the owners of Colstrip which has since been amended to add additional claims. The lawsuit alleges that certain domestic water wells and the Colstrip water supply pond were contaminated by seepage from a Colstrip Units 1 & 2 effluent holding pond, that seepage from Colstrip Units 1 & 2 have decreased property values and that seepage from the Colstrip water supply pond caused structural damage to buildings and toxic mold. In December 2005, Colstrip Unit 1 & 2 owners extended city water to certain residents who lived near the plant, including the domestic well plaintiffs. Discovery is ongoing and the case is currently scheduled for trial in January 2008.

On May 18, 2005, the Environmental Protection Agency (EPA) enacted the Clean Air Mercury Rule (CAMR) that will permanently cap and reduce mercury emissions from coal-fired power plants. The Montana Board of Environmental Review approved a more stringent rule to limit mercury emissions from coal-fired plants on October 16, 2006 (0.9 lbs/TBtu, instead of the federal 1.4 lbs/TBtu). The Colstrip owners are still evaluating the potential impact of the new Montana rule and it is still unknown whether the new rule will be appealed. Preliminary treatment technology studies undertaken by the Colstrip owners estimate that PSE's portion of the costs to comply with the new rule could be as much as $75.0 million in construction expenditures, but this number could change as new information becomes available.

In December 2003, the EPA issued an Administrative Consent Order (ACO) which alleged violation of the Clean Air Act permit requirement to submit, for review and approval by the EPA, an analysis and proposal for reducing emissions of nitrogen oxide to address visibility concerns upon the occurrence of certain triggering events which EPA asserts occurred in 1980. Although Colstrip owners believe that the ACO is unfounded, the Colstrip owners signed a settlement agreement in December 2006 that is now awaiting signature by the EPA, and then will be entered by the court. The agreement includes installation of low nitrogen oxide equipment installation on Colstrip Units 3 & 4 which will cost PSE approximately $2.65 million.

On June 15, 2005, the EPA issued the Clean Air Visibility Rule to address regional haze or regionally-impaired visibility caused by multiple sources over a wide area. The rule defines Best Available Retrofit Technology requirements for electric generating units, including presumptive limits for sulfur dioxide and nitrogen oxide controls for large units. Colstrip was originally required to submit analyses of visibility impacts for Colstrip 1 & 2 by December 2006 but the EPA has not yet completed the required preliminary analyses. PSE cannot yet determine the need for or costs of additional controls to comply with this rule, which could be significant.

NOTE 19. *Taxes Other Than Income Taxes*

(DOLLARS IN THOUSANDS)	2006	2005	2004
Taxes other than income taxes:			
Real estate and personal property	$ 39,832	$ 44,472	$ 43,843
State business	107,140	93,893	82,408
Municipal and occupational	97,671	85,154	72,405
Other	33,144	30,841	27,766
Total taxes other than income taxes	$ 277,787	$ 254,360	$ 226,422
Charged to:			
Operating expense	$ 255,712	$ 233,742	$ 208,989
Other accounts, including construction work in progress	22,075	20,618	17,433
Total taxes other than income taxes	$ 277,787	$ 254,360	$ 226,422

NOTE 20. *Regulation and Rates*

ELECTRIC REGULATION AND RATES

STORM DAMAGE DEFERRAL ACCOUNTING

On February 18, 2005, the Washington Commission issued a general rate case order that defined deferrable catastrophic/extraordinary losses and provided that costs in excess of $7.0 million annually may be deferred for qualifying storm damage costs that meet the IEEE outage criteria for system average interruption duration index. In 2006, PSE incurred $103.2 million in storm-related electric transmission and distribution system restoration costs, of which $92.3 million was deferred for future recovery in electric rates and will be determined in a future general rate case.

ELECTRIC GENERAL RATE CASE

On January 5, 2007, the Washington Commission issued its order in PSE's electric general rate case filed in February 2006, approving a general rate decrease for electric customers of $22.8 million or 1.3% annually. The rates for electric customers are effective beginning January 13, 2007. In its order, the Washington Commission approved a weighted cost of capital of 8.4%, or 7.06% after-tax, and a capital structure that included 44.0% common equity with a return on equity of 10.4%. The Washington Commission had earlier approved (on June 28, 2006) a power cost only rate case (PCORC) increase of $96.1 million annually effective July 1, 2006.

POWER COST ONLY RATE CASE

PCORC, a limited-scope proceeding, was created in 2002 by the Washington Commission to periodically reset power cost rates. The main objective of the PCORC proceeding is to provide for timely review of new resource acquisitions costs and inclusion of such costs in rates at the time the new resource goes into service. To achieve this objective, the Washington Commission agreed to an expedited five-month PCORC decision timeline rather than the statutory 11-month timeline for a general rate case.

On October 20, 2005, the Washington Commission approved a PCORC filing that increased electric rates 3.7% or $55.6 million annually. Included in the increase is the recovery of capital and operating costs of the Hopkins Ridge wind generating facility. The Hopkins Ridge wind generating facility was completed on November 27, 2005. As a wind generating facility, Hopkins Ridge is eligible for Federal Production Tax Credits (PTCs) that will ultimately offset some of the costs associated with generating power from Hopkins Ridge. The PTC is a tax credit provided by the Federal government for generating electricity from certain renewable resources. The current amount of the tax credit is $0.019 per kilowatt hour (kWh) for wind generation and may be subject to inflation adjustments over time. The tax credit can be claimed for 10 years for a new wind project put into service prior to January 1, 2008. The use of the credit is restricted to offset only 25% of current taxes payable. Unused credits can be carried forward for up to 20 years.

In the Washington Commission's October 2005 order, a new tariff schedule was approved which provides for the pass through to ratepayers of all benefits of the PTCs for the Hopkins Ridge project. This mechanism (a PTC Tracker) will pass through to the customer the actual production tax credits of the Hopkins Ridge project as they are generated. The PTC Tracker would not be subject to the sharing bands in the PCA. The credits passed through to the customer will be adjusted by the carrying costs of unused PTCs. Since the customer is receiving the benefit of the tax credits as they are generated and the Company does not receive a credit from the IRS until the tax credits are utilized, the Company is reimbursed its carrying costs for funds through this calculation.

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 and the addition of Wild Horse to the wind portfolio.

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 established in an electric rate case. The cumulative maximum pre-tax earnings exposure due to power cost variations over the four-year period ending June 30, 2006 was limited to $40.0 million plus 1.0% of the excess. In October 2005, the Washington Commission approved a shift to an annual PCA measurement period from January through December starting in 2007. On January 5, 2007, the Washington Commission approved the PCA mechanism for continuation under the same annual graduated scale without a cumulative cap for excess power costs. All significant variable power supply cost variables (hydroelectric and wind generation, market price for purchased power and surplus power, natural gas and coal fuel price, generation unit forced outage risk and transmission cost) are included in the PCA mechanism.

The PCA mechanism apportions increases or decreases in power costs, on a calendar year basis, between PSE and its customers on a graduated scale:

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 allowed for a reduction to 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 $40.0 million plus 1.0% of the excess. Power cost variation after December 31, 2006 will be apportioned on a calendar year basis, without a cumulative cap.*

Accounting Orders

On April 26, 2006, the Washington Commission approved an accounting petition on a temporary basis to defer an $89.0 million one-time capacity reservation charge along with accrual of interest at the authorized after-tax rate of return. As part of the general rate case order of January 5, 2007, the Washington Commission approved the regulatory accounting treatment that had been approved in the accounting petition. The payment was made in relation to an agreement for the purchase of power from Chelan County PUD (Chelan). PSE and Chelan have entered into an agreement which provides for the purchase of 25.0% of the output of Chelan's Rock Island (622 megawatts (MW)) and Rocky Reach (1,237 MW) dams on the Columbia River. The agreement called for PSE to make a one-time payment of $89.0 million on April 27, 2006. Then, upon the expiration of the existing contracts in 2011, PSE will begin purchasing 25.0% of the output at the projects' costs for the next 20 years.

On January 25, 2006, the Washington Commission approved an accounting order to defer, as a regulatory liability, two payments in the amount of $42.0 million and $13.0 million received from Duke Energy Trading and Marketing (Duke) in December 2005 in return for assuming the gas transportation capacity on Northwest Pipeline and Westcoast Pipeline from Duke Energy Trading and Marketing. The regulatory liability will be amortized to gas costs from January 2006 through October 2017 based upon the approved schedule. These credits are an offset to gas transportation costs that are in excess of PSE's gas transportation capacity needs. The $42.0 million payment was received to compensate the Company for the Northwest capacity payments that must be made until February 2011 when the capacity will be needed to serve load. The $13.0 million payment was received to compensate the Company for the difference between the assumed tariff rates and market value of the Westcoast Pipeline capacity through October 2017.

On April 7, 2004, the Washington Commission approved PSE's recovery on the unamortized White River plant investment. At December 31, 2006, the White River project net book value totaled $69.1 million, which included $43.4 million of net utility plant, $17.1 million of capitalized FERC licensing costs, $4.3 million of costs related to construction work in progress and $1.8 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. Any proceeds from the sale of the White River assets and water rights will reduce the balance of the deferred regulatory asset. Neither the outcome of this matter nor any potential associated financial impacts can be predicted at this time.

GAS REGULATION AND RATES

GAS GENERAL RATE CASE

On January 5, 2007, the Washington Commission issued its order in PSE's gas general rate case, granting an increase for gas customers of $29.5 million or 2.8% annually, effective beginning January 13, 2007. In its order the Washington Commission approved the same weighted cost of capital of 8.4% or 7.06% after-tax and capital structure that included 44.0% common equity with a return on equity of 10.4%, consistent with the Company's electric operations.

PURCHASED GAS ADJUSTMENT

PSE has a PGA mechanism in retail gas rates to recover variations in gas supply and transportation costs. Variations in gas rates are passed through to customers, therefore PSE's gas margin and net income are not affected by such variations. On September 27, 2006, the Washington Commission approved a revision of PSE's 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 following rate adjustments were approved by the Washington Commission in relation to the PGA mechanism during 2006, 2005 and 2004:

EFFECTIVE DATE	PERCENTAGE INCREASE IN RATES	ANNUAL INCREASE IN REVENUES (DOLLARS IN MILLIONS)
October 1, 2006	10.2%	$ 95.1
October 1, 2005	14.7%	121.6
October 1, 2004	17.6%	121.7

NOTE 21. *Other*

The Washington Commission issued an order on May 13, 2004 determining that PSE did not prudently manage gas costs for the Tenaska electric generating plant and ordered PSE to adjust its PCA deferral account to reflect a disallowance of accumulated costs under the PCA mechanism for these excess costs. The increase in purchased electricity expense resulting from the disallowance totaled $9.0 million, $4.1 million and $43.4 million in 2006, 2005 and 2004, respectively. The order also established guidelines and a benchmark to determine PSE's recovery on the Tenaska regulatory asset starting with the PCA 3 period (July 1, 2004) through the expiration of the Tenaska contract in the year 2011. The benchmark is defined as the original cost of the Tenaska contract adjusted to reflect the 1.2% disallowance from a 1994 Prudence Order.

In December 2003, PSE notified FERC that it rejected the 1997 license for the White River project because the 1997 license contained terms and conditions that rendered ongoing operations of the project uneconomical relative to alternative resources. As a result, generation of electricity ceased at the White River project on January 15, 2004. At December 31, 2006, the White River project net book value totaled $69.1 million, which included $43.4 million of net utility plant, $17.1 million of capitalized FERC licensing costs, $4.3 million of costs related to construction work in progress and $1.8 million related to dam operation and safety. PSE sought recovery of the relicensing, other construction work in progress and dam operations and safety costs in its general rate filing of April 2004, over a 10-year amortization period. In the third quarter 2004, the Washington Commission staff recommended that PSE be allowed recovery of the White River net utility plant costs noted above, but defer any amortization of the FERC licensing and other costs until all costs and any sales proceeds are known. On February 18, 2005, the Washington Commission agreed to allow PSE to recover the White River net utility plant costs noted above. However, amortization of the FERC licensing and other costs will not begin until all costs and any sales proceeds are known.

In November 2005, Puget Energy sold 15 million shares of common stock to Lehman Brothers Inc. for $312.0 million before underwriting discount. The net proceeds of approximately $309.8 million were invested in PSE and used to repay short-term debt incurred primarily to fund PSE's construction program.

In January 2003, FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46), as further revised in December 2003 with FIN 46R, which clarifies the application of Accounting Research Bulletin No. 51, "Consolidated Financial Statements," to certain entities in which equity investors do not have a controlling interest or sufficient equity at risk for the entity to finance its activities without additional financial support. FIN 46R requires that if a business entity has a controlling financial interest in a variable interest entity, the financial statements must be included in the consolidated financial statements of the business entity. The adoption of FIN 46R for all interests in variable interest entities created after January 31, 2003 was effective immediately. For variable interest entities created before February 1, 2003, it was effective July 1, 2003. The adoption of FIN 46R was effective March 31, 2004 for the Company. FIN 46R also impacted the treatment of the Company's mandatorily redeemable preferred securities of a wholly owned subsidiary trust holding solely junior subordinated debentures of the corporation (trust preferred securities). Previously, these trust preferred securities were consolidated into the Company's operations. As a result of FIN 46R, these securities have been deconsolidated and were classified as junior subordinated debentures of the corporation payable to a subsidiary trust holding mandatorily redeemable preferred securities (junior subordinated debt). This change had no impact on the Company's results of operations. The Company also evaluated its power purchase agreements and determined that three counterparties may be considered variable interest entities. As a result, 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 determined that it does not have a contractual right to such information. PSE will continue to submit requests for information to the counterparties on a quarterly basis to determine if FIN 46R is applicable.

For the three power purchase 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 power purchase 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 2006, 2005 and 2004 for these three entities was $259.8 million, $267.0 million and $251.2 million, respectively.

NOTE 22. *Commitments and Contingencies*

For the year ended December 31, 2006, approximately 23.1% of the Company's energy output was obtained at an average cost of approximately $0.014 per kWh through long-term contracts with several of the Washington Public Utility Districts (PUDs) owning hydroelectric projects on the Columbia River.

The purchase of power from the Columbia River projects is on a pro rata share basis under which the Company pays a proportionate share of the annual debt service, operating and maintenance costs and other expenses associated with each project in proportion to the contractual shares that PSE obtains from that project. In these instances, PSE's payments are not contingent upon the projects being operable, which means PSE is required to make the payments even if power is not being delivered. These projects are financed through substantially level debt service payments and their annual costs should not vary significantly over the term of the contracts unless additional financing is required to meet the costs of major maintenance, repairs or replacements, or license requirements. The Company's share of the costs and the output of the projects is subject to reduction due to various withdrawal rights of the PUDs and others over the lives of the contracts.

As of December 31, 2006, the Company was entitled to purchase portions of the power output of the PUDs' projects as set forth in the following tabulation:

				Company's Annual Amount Purchasable (Approximate)		
Project	Contract Exp. Date	License[1] Exp. Date	Total Bonds Outstanding 12/31/06[2] (Millions)	% of Output	Megawatt Capacity	Cost[3] (Millions)
Rock Island						
Original units	2012	2029	$ 109.3	50.0	} 330	$ 34.4
Additional units	2012	2029	322.4	50.0		
Rocky Reach [8]	2011	2006	380.2	38.9	501	27.2
Wells	2018	2012	208.4	29.9	251	11.0
Priest Rapids [4,5,6]	TBD[7]	TBD[7]	265.5	4.3	39	9.2
Wanapum [4,5,6]	2009	TBD[7]	441.8	10.8	106	4.3
Total			$ 1,727.6		1,227	$ 86.1

1 *The Company is unable to predict whether the licenses under the Federal Power Act will be renewed to the current licensees. FERC has issued orders for the Rocky Reach, Wells and Priest Rapids/Wanapum projects under Section 22 of the Federal Power Act, which affirm the Company's contractual rights to receive power under existing terms and conditions even if a new licensee is granted a license prior to expiration of the contract term.*

2 *The contracts for purchases initially were generally coextensive with the term of the PUD bonds associated with the project. Under the terms of some financings and re-financings, however, long-term bonds were sold to finance certain assets whose estimated useful lives extend beyond the expiration date of the power sales contracts. Of the total outstanding bonds sold for each project, the percentage of principal amount of bonds which mature beyond the contract expiration date are: 77.1% at Rock Island; 64.6% at Rocky Reach; and 29.0% at Wells. There are no maturities beyond the contract expiration date for Priest Rapids and Wanapum which assumes a 40-year FERC license extension.*

3 *The components of 2006 costs associated with the interest portion of debt service are: Rock Island, $13.3 million for all units; Rocky Reach, $8.2 million; Wells, $3.2 million; Priest Rapids, $0.4 million; and Wanapum, $1.5 million.*

4 *On December 28, 2001, PSE signed a contract offer for three new contracts related to the Priest Rapids and Wanapum Developments. On April 12, 2002, PSE signed amendments to those agreements which are technical clarifications of certain sections of the agreements. On May 27, 2005, PSE signed additional amendments to those agreements which provided technical clarifications of certain sections of the agreements and consolidated the terms into two contracts. Under the terms of these contracts, PSE will continue to obtain capacity and energy for the term of any new FERC license to be obtained by Grant County PUD. The new contracts' terms begin in November of 2005 for the Priest Rapids Development and in November of 2009 for the Wanapum Development. On March 8, 2002, the Yakama Nation filed a complaint with FERC which alleged that Grant County PUD's new contracts unreasonably restrain trade and violate various sections of the FPA and Public Law 83-544. On November 21, 2002, FERC dismissed the complaint while agreeing that certain aspects of the complaint had merit. As a result, FERC has ordered Grant County PUD to remove specific sections of the contract which constrain the parties to the Grant County PUD contracts from competing with Grant County PUD for a new license. A rehearing was requested but was denied by FERC on April 16, 2003. Both the Yakama Nation and Grant County PUD have appealed the FERC decision and the appeals have been consolidated in the Ninth Circuit Court of Appeals. The complaint is still pending and is in a mediation process.*

5 *Grant County PUD filed an "Application for New License for the Priest Rapids Project" on October 29, 2003 and the original FERC license expired at the end of October 2005. Grant County PUD continues to operate the Priest Rapids Project under annual license extensions pending issuance of a new FERC license and the new contracts will be concurrent with the new license which will be at least 30 years.*

6 *Unlike PSE's expiring contracts with Grant County PUD, in the new contracts PSE's share of power from the Priest Rapids Development and Wanapum Development declines over time as Grant County PUD's load increases. PSE's share of the Wanapum Development will remain at 10.8% until November 2009 and will be adjusted annually thereafter for the remaining term of the new contracts. PSE's share of the Priest Rapids Development declines to approximately 4.3% in 2006 and will be adjusted annually for the remaining term of the new contract.*

7 *To be determined. (See notes 4-6.)*

8 *On February 3, 2006, PSE and Chelan entered into a new Power Sales Agreement and a related Transmission Agreement for 25.0% of the output of Chelan's Rocky Reach and Rock Island hydroelectric generating facilities located on the mid-Columbia River in exchange for PSE paying 25.0% 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). The agreements have been approved by both FERC and the WUTC.*

The following table summarizes the Company's estimated payment obligations for power purchases from the Columbia River, contracts with other utilities and contracts under non-utility generators under the Public Utility Regulatory Policies Act (PURPA). These contracts have varying terms and may include escalation and termination provisions.

(Dollars in millions)	2007	2008	2009	2010	2011	2012 & There-after	Total
Columbia River projects	$ 97.7	$ 100.0	$ 105.0	$ 107.2	$ 111.6	$ 1,762.0	$ 2,283.5
Other utilities	83.0	83.8	85.9	83.3	37.1	235.1	608.2
Non-utility generators	200.0	195.4	201.2	199.7	200.1	105.1	1,101.5
Total	$ 380.7	$ 379.2	$ 392.1	$ 390.2	$ 348.8	$ 2,102.2	$ 3,993.2

Total purchased power contracts provided the Company with approximately 9.6 million, 9.6 million and 9.4 million megawatt hours (MWh) of firm energy at a cost of approximately $421.7 million, $419.7 million and $404.7 million for the years 2006, 2005 and 2004, respectively.

As part of its electric operations and in connection with the 1997 restructuring of the Tenaska Power Purchase Agreement, PSE is obligated to deliver to Tenaska up to 48,000 MMBtu (one million British thermal units, equal to one Dth) per day of natural gas for operation of Tenaska's natural gas-fired cogeneration facility. This obligation continues for the remaining term of the agreement, provided that no deliveries are required during the month of May. The price paid by Tenaska for this gas is reflective of the daily price of gas at the United States/Canada border near Sumas, Washington. PSE has entered into a financial arrangement to hedge a portion, 5,000 MMBtu to 10,000 MMBtu per day, of future gas supply costs associated with this obligation. The Company has a maximum financial obligation under this hedge agreement of $1.1 million in 2007. The Company has obligations for gas supply amounting to $8.9 million in 2007 for the Tenaska plant.

As part of its electric operations and in connection with the 1999 buyout of the Cabot gas supply contract, PSE is obligated to deliver to Encogen up to 21,800 MMBtu per day of natural gas for operation of the Encogen natural gas-fired cogeneration facility. This obligation continues for the remaining term of the original Cabot agreement. The Company entered into a financial arrangement to hedge a portion of future gas supply costs associated with this obligation, 10,000 MMBtu per day, for the remaining term of the agreement. The Company has a maximum financial obligation under this hedge agreement of $9.2 million in 2007 and $9.6 million in 2008. Depending on actual market prices, these costs will be partially, or perhaps entirely, offset by floating price payments received under the hedge arrangement. Encogen has two gas supply agreements that comprise 40% of the plant's requirements with remaining terms ranging from less than 1 year to 2.5 years. The obligations under these contracts are $21.9 million in 2007 and $11.1 million in 2008. The Company has obligations for gas supply amounting to $2.0 million in 2007.

PSE enters into short-term energy supply contracts to meet its core customer needs. These contracts are generally classified as normal purchases and normal sales or in some cases recorded at fair value in accordance with SFAS No. 133 and SFAS No. 149. Commitments under these contracts are $181.2 million in 2007 and $19.8 million in 2008.

GAS SUPPLY

The Company has also entered into various firm supply, transportation and storage service contracts in order to ensure adequate availability of gas supply for its firm customers. Many of these contracts, which have remaining terms from less than 1 year to 17 years, provide that the Company must pay a fixed demand charge each month, regardless of actual usage. The Company contracts for all of its long-term gas supply on a firm basis, which means the Company has a 100% daily take obligation and the supplier has a 100% daily delivery obligation. The Company incurred demand charges in 2006 for firm gas supply, firm transportation service and firm storage and peaking service of $1.8 million, $93.5 million and $8.4 million, respectively. WNG CAP I, a PSE subsidiary, incurred demand charges in 2006 for firm transportation service of $3.2 million, which is included in the total Company demand charges. The Company incurred demand charges in 2006 for firm transportation service for the gas supply for its combustion turbines in the amount of $11.6 million, which is included in the total Company demand charges.

The following table summarizes the Company's obligations for future demand charges through the primary terms of its existing contracts. The quantified obligations are based on current contract prices and FERC authorized rates, which are subject to change.

DEMAND CHARGE OBLIGATIONS (DOLLARS IN MILLIONS)	2007	2008	2009	2010	2011	2012 & THERE-AFTER	TOTAL
Firm gas supply	$ 1.8	$ 1.0	$ 0.5	$ 0.5	$ 0.5	$ --	$ 4.3
Firm transportation service	109.1	94.8	75.5	35.7	35.7	219.1	569.9
Firm storage service	9.4	9.0	7.7	7.7	7.7	21.5	63.0
Total	$ 120.3	$ 104.8	$ 83.7	$ 43.9	$ 43.9	$ 240.6	$ 637.2

SERVICE CONTRACTS

On August 30, 2001, PSE and Alliance Data Systems Corp. (Alliance Data) announced a contract under which Alliance Data will provide data processing and billing services for PSE. In providing services to PSE under the 10-year agreement, Alliance Data will use ConsumerLinX software, PSE's customer-information software developed by a former subsidiary, ConneXt. Alliance Data acquired the assets of ConneXt, including the exclusive use of the ConsumerLinX software for five years with an option for renewal. Alliance Data will offer ConsumerLinX as part of its integrated, single-source customer relationship management solution for large-scale, regulated utility clients. The obligations under the contract are $23.3 million in 2007, $23.9 million in 2008, $24.5 million in 2009, $25.1 million in 2010 and $17.1 million thereafter.

In April 2004, PSE acquired a 49.85% interest in the Frederickson 1 generating facility. As part of that acquisition, PSE became subject to an existing long-term parts and service maintenance contract for the upkeep of the natural gas combined cycle unit. The contract was initiated in December 2000, and runs for the earlier of 96,000 factored fired hours or 18 years. The contract requires payments based on both a fixed and variable cost component, depending on how much the facility is used. PSE's share of the estimated obligation under the contract based on projected future use of the facility is $1.2 million in 2007, $6.3 million in 2008, $1.1 million in 2009, $2.6 million in 2010, $1.9 million in 2011 and $14.4 million in the aggregate thereafter.

In March 2005, in connection with its purchase of the Hopkins Ridge wind power project, PSE entered into an Operations, Maintenance and Warranty Agreement (OM&W Agreement) with Vestas-American Wind Technology, Inc. (Vestas), pursuant to which Vestas will operate, maintain, service and remedy any defects or deficiencies in the constructed wind turbine generators (WTGs) at Hopkins Ridge and their associated equipment on PSE's behalf. Vestas also provides certain warranties in relation to the availability, production and noise of the Hopkins Ridge project. The OM&W Agreement provides for a five-year term continuing until November 2010. The annual fee is approximately $2.6 million and will escalate on each January 1 during the term by the Consumer Price Index.

In September 2005, in connection with its purchase of the Wild Horse wind power project, PSE entered into a Service & Maintenance Agreement and a Warranty Agreement (the Agreements) with Vestas-American Wind Technology, Inc. (Vestas American), pursuant to which Vestas American will operate, maintain, service and remedy any defects or deficiencies in the constructed WTGs at Wild Horse and their associated equipment on PSE's behalf. Vestas American also provides certain warranties in relation to the availability performance of the Wild Horse project. The Agreements provide for a five-year term continuing until November 2011. The first-year annual fee is approximately $5.1 million and will escalate each January 1 thereafter during the term by the Gross Domestic Product Implicit Price Deflator (GDPIPD).

FREDONIA 3 AND 4 OPERATING LEASE

PSE leases two combustion turbines for its Fredonia 3 and 4 electric generating facility pursuant to a master operating lease that was amended for this purpose in April 2001. The lease has a term expiring in 2011, but can be canceled by PSE at any time. Payments under the lease vary with changes in the LIBOR. At December 31, 2006, PSE's outstanding balance under the lease was $51.1 million. The expected residual value under the lease is the lesser of $37.4 million or 60.0% 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 87.0% of the unamortized value of the equipment.

SURETY BOND

The Company has a self-insurance surety bond in the amount of $10.1 million guaranteeing compliance with the Industrial Insurance Act (workers' compensation) and nine self-insurer's pension bonds totaling $1.5 million.

ENVIRONMENTAL REMEDIATION

The Company is subject to environmental laws and regulations by federal, state and local authorities and has been required to undertake certain environmental investigative and remedial efforts as a result of these laws and regulations. The Company has also been named by the Environmental Protection Agency, the Washington State Department of Ecology, and/or other third parties as potentially responsible at several contaminated sites and manufactured gas plant sites. PSE has implemented an ongoing program to test, replace and remediate certain underground storage tanks (UST) as required by federal and state laws. The UST replacement component of this effort is finished, but PSE continues its work remediating and/or monitoring relevant sites. During 1992, the Washington Commission issued orders regarding the treatment of costs incurred by the Company for certain sites under its environmental remediation program. The orders authorize the Company to accumulate and defer prudently incurred cleanup costs paid to third parties for recovery in rates established in future rate proceedings, subject to Washington Commission review. The Company believes a significant portion of its past and future environmental remediation costs is recoverable from insurance companies, from third parties or from customers under a Washington Commission order. At December 31, 2006, the Company had $1.7 million and $34.6 million in deferred electric and gas environmental costs, respectively.

In November, 2006, PSE's Crystal Mountain Generation Station had an accidental release of approximately 18,000 gallons of diesel oil. PSE crews and consultants responded and worked with applicable state and federal agencies to control and remove the spilled product. Through February 2007, over 9,500 gallons have been removed. Due to weather and snow in particular (the site is located very near the Crystal Mountain Ski Resort), additional recovery of diesel is not feasible until later in 2007. However, the remaining recoverable diesel is presumed to be contained within a limited area and largely embedded in soils under the generator station. Total removal costs as of February 14, 2007 are approximately $8.8 million. PSE is currently projecting the total remediation cost to be between $10.3 million and $13.3 million. At December 31, 2006, PSE had an insurance receivable in the amount of $7.9 million accrued associated with the Crystal Mountain electric generating facility oil spill. PSE management will be filing proof of loss claims with insurers once damage repair costs are known within an acceptable level of precision.

LITIGATION

There are several actions in the U.S. Ninth Circuit Court of Appeals (Ninth Circuit) 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 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 Ninth Circuit actions may have on PSE.

NOTE 23. *Segment Information*

Puget Energy operates in one business segment referred to as the regulated utility segment. The regulated utility segment includes the account receivables securitization program. Puget Energy's regulated utility operation generates, purchases and sells electricity and purchases, transports and sells natural gas. The service territory of PSE covers approximately 6,000 square miles in the state of Washington.

One minor non-utility business segment which includes two PSE subsidiaries, and Puget Energy, is described as other. The PSE subsidiaries are a real estate investment, a development company and a holding company for a small non-utility wholesale generator. Reconciling items between segments are not significant.

Prior to 2005, InfrastruX was a reportable segment of Puget Energy. InfrastruX was sold on May 7, 2006 and is not considered a reportable segment. See Note 3 for InfrastruX summarized financial information and discussion of discontinued operations.

2006 (DOLLARS IN THOUSANDS)	REGULATED UTILITY	OTHER	RECONCILING ITEM	PUGET ENERGY TOTAL
Revenues	$ 2,897,864	$ 7,829	$ --	$ 2,905,693
Depreciation and amortization	262,129	212	--	262,341
Income tax	95,271	1,000	--	96,271
Operating income	323,497	3,119	--	326,616
Interest charges, net of AFUDC	183,922	--	--	183,922
Net income from continuing operations	172,735	(5,511)	--	167,224
Total assets	6,993,131	72,908	--	7,066,039
Construction expenditures - excluding equity AFUDC	749,516	--	--	749,516

2005 (DOLLARS IN THOUSANDS)	REGULATED UTILITY	OTHER	RECONCILING ITEM	PUGET ENERGY TOTAL
Revenues	$ 2,565,384	$ 7,826	$ --	$ 2,573,210
Depreciation and amortization	241,385	249	--	241,634
Income tax	87,749	860	--	88,609
Operating income	299,541	3,622	--	303,163
Interest charges, net of AFUDC	164,965	224	--	165,189
Net income from continuing operations	142,861	3,422	--	146,283
Total assets[1]	6,267,012	68,392	274,547	6,609,951
Construction expenditures - excluding equity AFUDC	568,381	--	--	568,381

2004 (DOLLARS IN THOUSANDS)	REGULATED UTILITY	OTHER	RECONCILING ITEM	PUGET ENERGY TOTAL
Revenues	$ 2,192,340	$ 6,537	$ --	$ 2,198,877
Depreciation and amortization	228,310	256	--	228,566
Income tax	75,754	1,002	--	76,756
Operating income	285,258	2,420	--	287,678
Interest charges, net of AFUDC	166,411	219	--	166,630
Net income from continuing operations	123,401	2,009	--	125,410
Total assets[1]	5,509,358	70,641	271,220	5,851,219
Construction expenditures - excluding equity AFUDC	393,891	--	--	393,891

1 *Reconciling item consists of assets of InfrastruX which is presented as discontinued operations.*

SUPPLEMENTAL QUARTERLY FINANCIAL DATA

The following unaudited amounts, in the opinion of the Company, include all adjustments (consisting of normal recurring adjustments) necessary for a fair statement of the results of operations for the interim periods. Quarterly amounts vary during the year due to the seasonal nature of the utility business.

PUGET ENERGY

(Unaudited; dollars in thousands except per share amounts) 2006 QUARTER	FIRST	SECOND	THIRD	FOURTH
Operating revenues	$ 877,735	$ 574,222	$ 519,463	$ 934,273
Operating income	112,825	66,540	52,254	94,998
Net income before cumulative effect of accounting change	92,520	53,529	15,922	57,156
Net income	92,609	53,529	15,922	57,156
Basic earnings per common share	$ 0.80	$ 0.46	$ 0.14	$ 0.49
Diluted earnings per common share	$ 0.79	$ 0.46	$ 0.14	$ 0.49

(Unaudited; dollars in thousands except per share amounts) 2005 QUARTER	FIRST	SECOND	THIRD	FOURTH
Operating revenues	$ 741,653	$ 510,114	$ 490,383	$ 831,061
Operating income	110,534	51,919	47,528	93,180
Net income before cumulative effect of accounting change	71,075	13,895	5,911	64,915
Net income	71,075	13,895	5,911	64,844
Basic earnings per common share	$ 0.71	$ 0.14	$ 0.06	$ 0.60
Diluted earnings per common share	$ 0.71	$ 0.13	$ 0.06	$ 0.60

PUGET SOUND ENERGY

(Unaudited; dollars in thousands) 2006 QUARTER	FIRST	SECOND	THIRD	FOURTH
Operating revenues	$ 877,735	$ 574,224	$ 519,463	$ 934,273
Operating income	113,002	66,829	52,305	95,353
Net income before cumulative effect of accounting change	73,750	30,100	15,632	57,168
Net income	73,839	30,100	15,632	57,168

(Unaudited; dollars in thousands) 2005 QUARTER	FIRST	SECOND	THIRD	FOURTH
Operating revenues	$ 741,653	$ 510,114	$ 490,383	$ 831,062
Operating income	110,555	52,044	47,705	93,195
Net income before cumulative effect of accounting change	72,182	12,166	6,170	56,323
Net income	72,182	12,166	6,170	56,252

SCHEDULE I

Condensed Financial Information of Puget Energy

Puget Energy Condensed Statements of

INCOME

(DOLLARS IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)

FOR YEARS ENDED DECEMBER 31	2006	2005	2004
Equity in earnings of subsidiary	$ 177,585	$ 146,769	$ 126,192
Other operations and maintenance	(1,830)	(1,354)	(983)
Income taxes	957	1,021	420
Other income (deductions):			
Charitable foundation contributions	(15,000)	--	--
Interest Income	356	--	--
Interest expense	--	(224)	(219)
Income taxes	5,245	--	--
Net income from continuing operations	167,313	146,212	125,410
Equity in earnings of discontinued subsidiary	51,903	9,514	(70,388)
Net income	$ 219,216	$ 155,726	$ 55,022
Basic earnings per share from continuing operations	1.44	1.43	1.26
Discontinued operations	0.45	0.09	(0.71)
Basic earnings per share	$ 1.89	$ 1.52	$ 0.55
Diluted earnings per share from continuing operations	$ 1.44	$ 1.42	$ 1.25
Discontinued operations	0.44	0.09	(0.70)
Diluted earnings per share	$ 1.88	$ 1.51	$ 0.55

See accompanying notes to the consolidated financial statements.

Puget Energy Condensed

BALANCE SHEETS

(DOLLARS IN THOUSANDS)

AT DECEMBER 31	2006	2005
Assets:		
Investment in & advances to Subs	$ 761,686	$ 714,214
Current assets:		
Cash	25	1
Receivables from affiliates	24,659	1,618
Prepayments and other	570	573
Tax receivable	388	--
Total current assets	25,642	2,192
Long-term assets:		
Restricted cash	3,813	--
Deferred income taxes	3,939	353
Other	217	460
Total long-term assets	7,969	813
Total assets	$ 795,297	$ 717,219
Capitalization and liabilities:		
Common equity	$ 785,432	$ 699,148
Total capitalization	785,432	699,148
Minority interest in discontinued operations	--	6,816
Current liabilities:		
Accounts payable	325	--
Payable to affiliates	--	5,427
Taxes	--	960
Salaries and wages	531	--
Other	--	4,763
Total current liabilities	856	11,150
Long-term liabilities:		
Other deferred credits	9,009	105
Total long-term liabilities	9,009	105
Total capitalization and liabilities	$ 795,297	$ 717,219

See accompanying notes to the consolidated financial statements.

Puget Energy Condensed Statements of

CASH FLOWS

(DOLLARS IN THOUSANDS)

FOR YEARS ENDED DECEMBER 31	2006	2005	2004
Operating activities:			
Net income	$ 219,216	$ 155,726	$55,022
Adjustments to reconcile net income to net cash provided by operating activities:			
Deferred income taxes and tax credits – net	(3,586)	(252)	63
Equity in earnings of discontinued subsidiary	(51,903)	(9,514)	70,388
Equity in earnings of subsidiary	(177,586)	(146,769)	(126,192)
Other	(94)	303	(450)
Dividends received from subsidiaries	109,782	89,199	87,700
(Increase) decrease in accounts receivable	(355)	(1,617)	--
(Increase) decrease in tax receivable	(388)	319	(319)
(Increase) decrease in prepayments	--	--	9
Increase (decrease) in accounts payable	325	--	--
Increase (decrease) in affiliated payables	(5,427)	4,297	304
Increase (decrease) in accrued tax payable	(960)	960	--
Increase (decrease) in accrued expenses and other	(4,763)	(208)	--
Net cash provided (used) by operating activities	84,261	92,444	86,525
Investing activities:			
Cash proceeds from sale of InfrastruX	275,000	--	--
Increase in restricted cash	(3,813)	--	--
Investment in subsidiaries	(70,114)	(314,686)	(5,016)
Loans to subsidiaries	(24,303)	--	--
Net cash provided (used) by investing activities	176,770	(314,686)	(5,016)
Financing activities:			
Dividends paid	(104,332)	(88,071)	(86,873)
Common stock issued	5,877	317,607	5,413
Long-term debt and lease payments	(151,849)	(5,000)	--
Payments made to minority interest	(10,451)	--	--
Issue costs of stocks	(252)	(2,293)	(49)
Net cash provided (used) by financing activities	(261,007)	222,243	(81,509)
Increase (decrease) in cash	24	1	--
Cash at beginning of year	1	--	--
Cash at end of year	$ 25	$ 1	$ --

See accompanying notes to the consolidated financial statements.

SCHEDULE II

Valuation and Qualifying Accounts and Reserves

PUGET ENERGY (DOLLARS IN THOUSANDS)	BALANCE AT BEGINNING OF PERIOD	ADDITIONS CHARGED TO COSTS AND EXPENSES	DEDUCTIONS	BALANCE AT END OF PERIOD
YEAR ENDED DECEMBER 31, 2006				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 3,074	$ 7,623	$ 7,935	$ 2,762
Reserve on wholesale sales	41,488	--	--	41,488
Deferred tax asset valuation allowance	16,075	--	16,075	--
YEAR ENDED DECEMBER 31, 2005				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 2,670	$ 8,275	$ 7,871	$ 3,074
Reserve on wholesale sales	41,488	--	--	41,488
Deferred tax asset valuation allowance	17,988	--	1,913	16,075
YEAR ENDED DECEMBER 31, 2004				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 2,484	$ 7,343	$ 7,157	$ 2,670
Reserve on wholesale sales	41,488	--	--	41,488
Deferred tax asset valuation allowance	--	17,988	--	17,988

PUGET SOUND ENERGY (DOLLARS IN THOUSANDS)	BALANCE AT BEGINNING OF PERIOD	ADDITIONS CHARGED TO COSTS AND EXPENSES	DEDUCTIONS	BALANCE AT END OF PERIOD
YEAR ENDED DECEMBER 31, 2006				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 3,074	$ 7,623	$ 7,935	$ 2,762
Reserve on wholesale sales	41,488	--	--	41,488
YEAR ENDED DECEMBER 31, 2005				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 2,670	$ 8,275	$ 7,871	$ 3,074
Reserve on wholesale sales	41,488	--	--	41,488
YEAR ENDED DECEMBER 31, 2004				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 2,484	$ 7,343	$ 7,157	$ 2,670
Reserve on wholesale sales	41,488	--	--	41,488

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. 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 President and Chief Executive Officer and 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 December 31, 2006, the end of the period covered by this report. Based upon that evaluation, the President and Chief Executive Officer and 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 December 31, 2006 that have materially affected, or are reasonably likely to materially affect, Puget Energy's internal control over financial reporting.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Puget Energy's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). Under the supervision and with the participation of Puget Energy's President and Chief Executive Officer and Senior Vice President Finance and Chief Financial Officer, Puget Energy's management assessed the effectiveness of internal control over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, Puget Energy's management concluded that its internal control over financial reporting was effective as of December 31, 2006.

Puget Energy's management assessment of the effectiveness of internal control over financial reporting as of December 31, 2006, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

PUGET SOUND ENERGY

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Under the supervision and with the participation of PSE's management, including the President and Chief Executive Officer and 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 December 31, 2006, the end of the period covered by this report. Based upon that evaluation, the President and Chief Executive Officer and 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 December 31, 2006, that have materially affected, or are reasonably likely to materially affect, PSE's internal control over financial reporting.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

PSE's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). Under the supervision and with the participation of PSE's President and Chief Executive Officer and Senior Vice President Finance and Chief Financial Officer, Puget Sound Energy's management assessed the effectiveness of internal control over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, PSE's management concluded that its internal control over financial reporting was effective as of December 31, 2006.

PSE's management assessment of the effectiveness of internal control over financial reporting as of December 31, 2006 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE AND CORPORATE GOVERNANCE

PUGET ENERGY

The information required by this item with respect to Puget Energy is incorporated herein by reference to the material under "Available Information" in Part I of this report and "Proposal 1 - Election of Directors," "Directors Continuing in Office," "Board of Directors and Corporate Governance," "Director Compensation" and "Security Ownership of Directors, Executive Officers and Certain Beneficial Owners" in Puget Energy's proxy statement for its 2007 Annual Meeting of Shareholders (Commission file No. 1-16305). Reference is also made to the information regarding Puget Energy's executive officers set forth in Part I of this report.

PUGET SOUND ENERGY

The information called for by Item 10 with respect to PSE is omitted pursuant to General Instruction I(2)(c) to Form 10-K (omission of information by certain wholly owned subsidiaries).

ITEM 11. EXECUTIVE COMPENSATION

PUGET ENERGY

The information required by this item with respect to Puget Energy is incorporated herein by reference to the material under "Director Compensation," "Compensation Discussion and Analysis" and "Summary Compensation" in Puget Energy's proxy statement for its 2007 Annual Meeting of Shareholders (Commission File No. 1-16305).

PUGET SOUND ENERGY

The information called for by Item 11 with respect to PSE is omitted pursuant to General Instruction I (2)(c) to Form 10-K (omission of information by certain wholly owned subsidiaries).

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED SHAREHOLDER MATTERS

PUGET ENERGY

EQUITY COMPENSATION PLAN INFORMATION

The information required by this item with respect to Puget Energy is incorporated herein by reference to the material under "Equity Compensation Plan Information" in Puget Energy's proxy statement for its 2007 Annual Meeting of Shareholders (Commission File No. 1-16305).

BENEFICIAL OWNERSHIP

The information required by this item with respect to Puget Energy is incorporated herein by reference to the material under "Security Ownership of Directors, Executive Officers and Certain Beneficial Owners" in Puget Energy's proxy statement for its 2007 Annual Meeting of Shareholders (Commission File No. 1-16305).

PUGET SOUND ENERGY

EQUITY COMPENSATION PLAN INFORMATION

The information called for by this item with respect to PSE is omitted pursuant to General Instruction I (2)(e) to Form 10-K (omission of information by wholly owned subsidiaries).

BENEFICIAL OWNERSHIP

As of December 31, 2006, all of the issued and outstanding shares of PSE's common stock were held beneficially and of record by Puget Energy.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

None.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The aggregate fees billed by PricewaterhouseCoopers LLP, the Company's independent registered public accounting firm, for the year ended December 31 were as follows:

	2006		2005	
(DOLLARS IN THOUSANDS)	PUGET ENERGY	PSE	PUGET ENERGY	PSE
Audit fees[1]	$ 1,653	$ 1,530	$ 2,023	$ 1,422
Audit related fees[2]	100	100	103	81
Tax fees[3]	34	34	45	33
Total	$ 1,787	$ 1,664	$ 2,171	$ 1,536

[1] *For professional services rendered for the audit of Puget Energy's and PSE's annual financial statements, reviews of financial statements included in the Companies' Forms 10-Q and consents and reviews of documents filed with the Securities and Exchange Commission. The 2006 fees are estimated and include an aggregate amount of $1.1 million and $1.0 million billed to Puget Energy and PSE, respectively, through December 2006. The 2005 fees include an aggregate amount of $1.1 million and $1.0 million billed to Puget Energy and PSE, respectively, through December 31, 2005.*

[2] *Consists of employee benefit plan audits, due diligence reviews and assistance with Sarbanes-Oxley readiness.*

[3] *Consists of tax consulting and tax return reviews.*

The Audit Committee of the Company has adopted policies for the pre-approval of all audit and non-audit services provided by the Company's independent auditor. The policies are designed to ensure that the provision of these services does not impair the auditor's independence. Under the policies, unless a type of service to be provided by the independent auditor has received general pre-approval, it will require specific pre-approval by an Audit Committee. In addition, any proposed services exceeding pre-approved cost levels will require specific pre-approval by an Audit Committee.

The annual audit services engagement terms and fees, as well as any changes in terms, conditions and fees relating to the engagement, are subject to specific pre-approval by the Audit Committees. In addition, on an annual basis, the Audit Committees grant general pre-approval for specific categories of audit, audit-related, tax and other services, within specified fee levels, that may be provided by the independent registered public accounting firm. With respect to each proposed pre-approved service, the independent registered public accounting firm is required to provide detailed back-up documentation to the Audit Committees regarding the specific services to be provided. Under the policies, the Audit Committees may delegate pre-approval authority to one or more of their members. The member or members to whom such authority is delegated shall report any pre-approval decision to an Audit Committee at its next scheduled meeting. The Audit Committees do not delegate responsibilities to pre-approve services performed by the independent registered public accounting firm to management.

For 2006 and 2005, all audit and non-audit services were pre-approved.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

a) Documents filed as part of this report:

1) *Financial Statements.* See index on page 63.

2) *Financial Statement Schedules*. Financial Statement Schedules of the Company located on page 125, as required for the years ended December 31, 2006, 2005 and 2004, consist of the following:

I. Condensed Financial Information of Puget

II. Valuation of Qualifying Accounts

3) Exhibits - see index on page 137.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, each registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PUGET ENERGY, INC.	**PUGET SOUND ENERGY**
/s/ Stephen P. Reynolds	/s/ Stephen P. Reynolds
Stephen P. Reynolds Chairman, President and Chief Executive Officer	Stephen P. Reynolds Chairman, President and Chief Executive Officer
Date: March 1, 2007	Date: March 1, 2007

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of each registrant and in the capacities and on the dates indicated.

SIGNATURE	TITLE	DATE
	(Puget Energy and PSE unless otherwise noted)	
/s/ Stephen P. Reynolds (Stephen P. Reynolds)	Chairman, President and Chief Executive Officer	March 1, 2007
/s/ Bertrand A. Valdman (Bertrand A. Valdman)	Senior Vice President Finance and Chief Financial Officer	
/s/ James W. Eldredge (James W. Eldredge)	Vice President, Corporate Secretary and Chief Accounting Officer	
/s/ William S. Ayer (William S. Ayer)	Director	
/s/ Phyllis J. Campbell (Phyllis J. Campbell)	Director	
/s/ Craig W. Cole (Craig W. Cole)	Director	
/s/ Stephen E. Frank (Stephen E. Frank)	Director	
/s/ Tomio Moriguchi (Tomio Moriguchi)	Director	
/s/ Dr. Kenneth P. Mortimer (Dr. Kenneth P. Mortimer)	Director	

/s/ Sally G. Narodick (Sally G. Narodick)	Director
/s/ Herbert B. Simon (Herbert B. Simon)	Director
/s/ George W. Watson (George W. Watson)	Director

EXHIBIT INDEX

Certain of the following exhibits are filed herewith. Certain other of the following exhibits have heretofore been filed with the Securities and Exchange Commission and are incorporated herein by reference.

3(i).1	Restated Articles of Incorporation of Puget Energy (Incorporated by reference to Exhibit 99.2, Puget Energy's Current Report on Form 8-K dated January 2, 2001, Commission File No. 333-77491).
3(i).2	Restated Articles of Incorporation of PSE (included as Annex F to the Joint Proxy Statement/Prospectus filed February 1, 1996, Registration No. 333-617).
3(ii).1	Amended and Restated Bylaws of Puget Energy dated March 7, 2003 (Exhibit 3(ii).1 to the Annual Report on Form 10-K for the fiscal year ended December 31, 2002, Commission File No. 1-16305 and 1-4393).
3(ii).2	Amended and Restated Bylaws of PSE dated March 7, 2003 (Exhibit 3(ii).2 to the Annual Report on Form 10-K for the fiscal year ended December 31, 2002, Commission File No. 1-16305 and 1-4393).
4.1	Fortieth through Eighty-fourth Supplemental Indentures defining the rights of the holders of PSE's Electric Utility First Mortgage Bonds (Exhibit 2-d to Registration No. 2-60200; Exhibit 4-c to Registration No. 2-13347; Exhibits 2-e through and including 2-k to Registration No. 2-60200; Exhibit 4-h to Registration No. 2-17465; Exhibits 2-l, 2-m and 2-n to Registration No. 2-60200; Exhibit 2-m to Registration No. 2-37645; Exhibits 2-o through and including 2-s to Registration No. 2-60200; Exhibit 5-b to Registration No. 2-62883; Exhibit 2-h to Registration No. 2-65831; Exhibit (4)-j-1 to Registration No. 2-72061; Exhibit (4)-a to Registration No. 2-91516; Exhibit (4)-b to Annual Report on Form 10-K for the fiscal year ended December 31, 1985, Commission File No. 1-4393; Exhibits (4)-b and (4)-c to Registration No. 33-45916; Exhibit (4)-c to Registration No. 33-50788; Exhibit (4)-a to Registration No. 33-53056; Exhibit 4.3 to Registration No. 33-63278; Exhibit 4.25 to Registration No. 333-41181; Exhibit 4.27 to Current Report on Form 8-K dated March 5, 1999; Exhibit 4.2 to Current Report on Form 8-K dated November 2, 2000; Exhibit 4.2 to Current Report on Form 8-K dated June 3, 2003; Exhibit 4.28 to Annual Report on Form 10-K for fiscal year ended December 31, 2004, Commission File No. 1-16305 and 1-4393; Exhibit 4.1 to Current Report on Form 8-K, dated May 23, 2005, Commission File No. 1-16305 and 1-4393; Exhibit 4.30 to Annual Report on Form 10-K for fiscal year ended December 31, 2005, Commission file No. 1-16305 and 1-4393); and Exhibit 4.1 to Current Report on Form 8-K dated September 14, 2006, Commission File No. 1-4393.
4.2	Indenture defining the rights of the holders of PSE's senior notes (incorporated herein by reference to Exhibit 4-a to PSE's Quarterly Report on Form 10-Q for the quarter ended June 30, 1998, Commission File No. 1-4393).
4.3	First Supplemental Indenture defining the rights of the holders of PSE's senior notes, Series A (incorporated herein by reference to Exhibit 4-b to PSE's Quarterly Report on Form 10-Q for the quarter ended June 30, 1998, Commission File No. 1-4393).
4.4	Second Supplemental Indenture defining the rights of the holders of PSE's senior notes, Series B (incorporated herein by reference to Exhibit 4.6 to PSE's Current Report on Form 8-K, dated March 5, 1999, Commission File No. 1-4393).
4.5	Third Supplemental Indenture defining the rights of the holders of PSE's senior notes, Series C (incorporated herein by reference to Exhibit 4.1 to PSE's Current Report on Form 8-K, dated November 2, 2000, Commission File No. 1-4393).
4.6	Fourth Supplemental Indenture defining the rights of the holders of PSE's senior notes (incorporated herein by reference to Exhibit 4.1 to PSE's Current Report on Form 8-K, dated June 3, 2003, Commission File No. 1-4393).
4.7	Rights Agreement dated as of December 21, 2000 between Puget Energy and Wells Fargo Bank, N.A., as Rights Agent (incorporated herein by reference to Exhibit 4.1 to Puget Energy's Registration Statement on Form S-3, dated January 11, 2007, Commission File No. 1-16305).
4.8	Indenture between PSE and the First National Bank of Chicago dated June 6, 1997 (incorporated herein by reference to Exhibit 4.1 of PSE's Quarterly Report on Form 10-Q for the quarter ended June 30, 1997, Commission File No. 1-4393).
4.9	Amended and Restated Declaration of Trust between Puget Sound Energy Capital Trust and the First National Bank of Chicago dated June 6, 1997 (incorporated herein by reference to Exhibit 4.2 of PSE's Quarterly Report on Form 10-Q for the quarter ended June 30, 1997, Commission File No. 1-4393).
4.10	Series A Capital Securities Guarantee Agreement between PSE and the First National Bank of Chicago dated June 6, 1997 (incorporated herein by reference to Exhibit 4.3 of PSE's Quarterly Report on Form 10-Q for the quarter ended June 30, 1997, Commission File No. 1-4393).

4.11 First Supplemental Indenture dated as of October 1, 1959 (Exhibit 4-D to Registration No. 2-17876).

4.12 Sixth Supplemental Indenture dated as of August 1, 1966 (Exhibit to Form 8-K for month of August 1966, File No. 0-951).

4.13 Seventh Supplemental Indenture dated as of February 1, 1967 (Exhibit 4-M, Registration No. 2-27038).

4.14 Sixteenth Supplemental Indenture dated as of June 1, 1977 (Exhibit 6-05 to Registration No. 2-60352).

4.15 Seventeenth Supplemental Indenture dated as of August 9, 1978 (Exhibit 5-K.18 to Registration No. 2-64428).

4.16 Twenty-second Supplemental Indenture dated as of July 15, 1986 (Exhibit 4-B.20 to Form 10-K for the year ended September 30, 1986, File No. 0-951).

4.17 Twenty-seventh Supplemental Indenture dated as of September 1, 1990 (Exhibit 4-B.20, Form 10-K for the year ended September 30, 1998, File No. 10-951).

4.18 Twenty-eighth Supplemental Indenture dated as of July 31, 1991 (Exhibit 4-A, Form 10-Q for the quarter ended March 31, 1993, File No. 0-951).

4.19 Twenty-ninth Supplemental Indenture dated as of June 1, 1993 (Exhibit 4-A to Registration No. 33-49599).

4.20 Thirtieth Supplemental Indenture dated as of August 15, 1995 (incorporated herein by reference to Exhibit 4-A of Washington Natural Gas Company's S-3 Registration Statement, Registration No. 33-61859).

4.21 Thirty-first Supplemental Indenture dated February 10, 1997 (Exhibit 4.30 to the Annual Report on Form 10-K for the fiscal year ended December 31, 2002, Commission File No. 1-6305 and 1-4393).

4.22 Thirty-second Supplemental Indenture dated April 1, 2005, defining the rights of the holders of PSE's gas utility First Mortgage Bond.

4.23 Thirty-third Supplemental Indenture dated April 27, 2005, defining the rights of the holders of PSE's gas utility First Mortgage Bond.

4.24 Pledge Agreement dated March 11, 2003 between Puget Sound Energy and Wells Fargo Bank Northwest, National Association, as Trustee (incorporated herein by reference to Exhibit 4.24 to the Company's Post-Effective Amendment No. 1 to Registration Statement on Form S-3 dated July 11, 2003, Commission File No. 333-82940-02).

4.25 Loan Agreement dated as of March 1, 2003, between the City of Forsyth, Rosebud County, Montana and Puget Sound Energy (incorporated herein by reference to Exhibit 4.25 to the Company's Post-Effective Amendment No. 1 to Registration Statement on Form S-3, dated July 11, 2003, Commission File No. 333-82490-02).

10.1 First Amendment dated as of October 4, 1961 to Power Sales Contract between Public Utility District No. 1 of Chelan County, Washington and PSE, relating to the Rocky Reach Project (Exhibit 13-d to Registration No. 2-24252).

10.2 First Amendment dated February 9, 1965 to Power Sales Contract between Public Utility District No. 1 of Douglas County, Washington and PSE, relating to the Wells Development (Exhibit 13-p to Registration No. 2-24252).

10.3 Contract dated November 14, 1957 between Public Utility District No. 1 of Chelan County, Washington and PSE, relating to the Rocky Reach Project (Exhibit 4-1-a to Registration No. 2-13979).

10.4 Power Sales Contract dated as of November 14, 1957 between Public Utility District No. 1 of Chelan County, Washington and PSE, relating to the Rocky Reach Project (Exhibit 4-c-1 to Registration No. 2-13979).

10.5 Power Sales Contract dated May 21, 1956 between Public Utility District No. 2 of Grant County, Washington and PSE, relating to the Priest Rapids Project (Exhibit 4-d to Registration No. 2-13347).

10.6 First Amendment to Power Sales Contract dated as of August 5, 1958 between PSE and Public Utility District No. 2 of Grant County, Washington, relating to the Priest Rapids Development (Exhibit 13-h to Registration No. 2-15618).

10.7 Power Sales Contract dated June 22, 1959 between Public Utility District No. 2 of Grant County, Washington and PSE, relating to the Wanapum Development (Exhibit 13-j to Registration No. 2-15618).

10.8 Agreement to Amend Power Sales Contracts dated July 30, 1963 between Public Utility District No. 2 of Grant County, Washington and PSE, relating to the Wanapum Development (Exhibit 13-1 to Registration No. 2-21824).

10.9 Power Sales Contract executed as of September 18, 1963 between Public Utility District No. 1 of Douglas County, Washington and PSE, relating to the Wells Development (Exhibit 13-r to Registration No. 2-21824).

10.10 Construction and Ownership Agreement dated as of July 30, 1971 between The Montana Power Company and PSE (Exhibit 5-b to Registration No. 2-45702).

10.11 Operation and Maintenance Agreement dated as of July 30, 1971 between The Montana Power Company and PSE (Exhibit 5-c to Registration No. 2-45702).

10.12 Contract dated June 19, 1974 between PSE and P.U.D. No. 1 of Chelan County (Exhibit D to Form 8-K dated July 5, 1974).

10.13 Transmission Agreement dated April 17, 1981 between the Bonneville Power Administration and PSE (Colstrip Project) (Exhibit (10)-55 to Annual Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393).

10.14 Transmission Agreement dated April 17, 1981 between the Bonneville Power Administration and Montana Intertie Users (Colstrip Project) (Exhibit (10)-56 to Annual Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393).

10.15 Ownership and Operation Agreement dated as of May 6, 1981 between PSE and other Owners of the Colstrip Project (Colstrip 3 and 4) (Exhibit (10)-57 to Annual Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393).

10.16 Colstrip Project Transmission Agreement dated as of May 6, 1981 between PSE and Owners of the Colstrip Project (Exhibit (10)-58 to Annual Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393).

10.17 Common Facilities Agreement dated as of May 6, 1981 between PSE and Owners of Colstrip 1 and 2, and 3 and 4 (Exhibit (10)-59 to Annual Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393).

10.18 Amendment dated as of June 1, 1968, to Power Sales Contract between Public Utility District No. 1 of Chelan County, Washington and PSE (Rocky Reach Project) (Exhibit (10)-66 to Annual Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393).

10.19 Transmission Agreement dated as of December 30, 1987 between the Bonneville Power Administration and PSE (Rock Island Project) (Exhibit (10)-74 to Annual Report on Form 10-K for the fiscal year ended December 31, 1988, Commission File No. 1-4393).

10.20 Power Sales Agreement between Northwestern Resources (formerly The Montana Power Company) and PSE dated as of October 1, 1989 (Exhibit (10)-4 to Quarterly Report on Form 10-Q for the quarter ended September 30, 1989, Commission File No. 1-4393).

10.21 Amendment No. 1 to the Colstrip Project Transmission Agreement dated as of February 14, 1990 among The Montana Power Company, The Washington Water Power Company (Avista), Portland General Electric Company , PacifiCorp and PSE (Exhibit (10)-91 to Annual Report on Form 10-K for the fiscal year ended December 31, 1990, Commission File No. 1-4393).

10.22 Agreement for Firm Power Purchase (Thermal Project) dated December 27, 1990 among March Point Cogeneration Company, a California general partnership comprising San Juan Energy Company, a California corporation; Texas-Anacortes Cogeneration Company, a Delaware corporation; and PSE (Exhibit (10)-4 to Quarterly Report on Form 10-Q for the quarter ended March 31, 1991, Commission File No. 1-4393).

10.23 Agreement for Firm Power Purchase dated March 20, 1991 between Tenaska Washington, Inc., a Delaware corporation, and PSE (Exhibit (10)-1 to Quarterly Report on Form 10-Q for the quarter ended June 30, 1991, Commission File No. 1-4393).

10.24 Amendment of Seasonal Exchange Agreement, dated December 4, 1991 between Pacific Gas and Electric Company and PSE (Exhibit (10)-107 to Annual Report on Form 10-K for the fiscal year ended December 31, 1991, Commission File No. 1-4393).

10.25 Capacity and Energy Exchange Agreement, dated as of October 4, 1991 between Pacific Gas and Electric Company and PSE (Exhibit (10)-108 to Annual Report on Form 10-K for the fiscal year ended December 31, 1991, Commission File No. 1-4393).

10.26 General Transmission Agreement dated as of December 1, 1994 between the Bonneville Power Administration and PSE (BPA Contract No. DE-MS79-94BP93947) (Exhibit 10.115 to Annual Report on Form 10-K for the fiscal year ended December 31, 1994, Commission File No. 1-4393).

10.27 PNW AC Intertie Capacity Ownership Agreement dated as of October 11, 1994 between the Bonneville Power Administration and PSE (BPA Contract No. DE-MS79-94BP94521) (Exhibit 10.116 to Annual Report on Form 10-K for the fiscal year ended December 31, 1994, Commission File No. 1-4393).

10.28 Amendment to Gas Transportation Service Contract dated July 31, 1991 between Washington Natural Gas Company and Northwest Pipeline Corporation (Exhibit 10-E.2 to Form 10-K for the year ended September 30, 1995, File No. 11271).

10.29 Firm Transportation Service Agreement dated January 12, 1994 between Northwest Pipeline Corporation and Washington Natural Gas Company for firm transportation service from Jackson Prairie (Exhibit 10-P to Form 10-K for the year ended September 30, 1994, File No. 1-11271).

10.30 Power Sales Contract dated April 15, 2002, between Public Utility District No. 2 of Grant County, Washington, and PSE, relating to the Priest Rapids Project. (Exhibit 10-1 to Form 10-Q for the quarter ended June 30, 2002, File No. 1-16305 and 1-4393).

10.31 Reasonable Portion Power Sales Contract dated April 15, 2002, between Public Utility District No. 2 of Grant County, Washington, and PSE, relating to the Priest Rapids Project. (Exhibit 10-2 to Form 10-Q for the quarter ended June 30, 2002, File No. 1-16305 and 1-4393).

10.32 Additional Power Sales Contract dated April 15, 2002, between Public Utility District No. 2 of Grant County, Washington, and PSE, relating to the Priest Rapids Project. (Exhibit 10-3 to Form 10-Q for the quarter ended June 30, 2002, File No. 1-16305 and 1-4393).

10.33 Amended and Restated Credit Agreement dated March 25, 2005 covering PSE and various banks named therein, Wachovia Bank National Association as administrative agent. (Exhibit 99.1 to Current Report on Form 8-K, dated March 29, 2005, Commission File No. 1-4393 and 1-16305).

10.34 First Amendment to the Amended and Restated Credit Agreement dated April 4, 2006 cover PSE and various banks named therein, Wachovia Bank National Association as administrative agent. (Exhibit 10.1 to the Current Report of Form 10-Q, dated March 31, 2006, Commission File Nos. 1-16305 and 1-4393).

10.35 Loan and Serving Agreement dated December 20, 2005, among PSE, PSE Funding, Inc., and J.P. Morgan Chase Bank as program agent (Exhibit 10.2 to the Current Report on Form 8-K dated December 22, 2005, Commission File No. 1-4393 and 1-16305).

10.36 Receivable Sale Agreement dated December 20, 2005, among PSE and PSE Funding, Inc. (Exhibit 10.1 to the Current Report on Form 8-K dated December 22, 2005, Commission File Nos. 1-16305 and 1-4393).

** 10.37 Puget Energy, Inc. Non-employee Director Stock Plan. (Appendix B to definitive Proxy Statement, dated March 7, 2005, Commission File No. 1-16305).

** 10.38 Puget Energy, Inc. Employee Stock Purchase Plan. (Incorporated herein by reference to Exhibit 99.1 to Puget Energy's Post Effective Amendment No. 1 to Form S-8 Registration Statement, dated January 2, 2001, Commission File No. 333-41113-99.)

** 10.39 Puget Energy 2005 Long-Term Incentive Plan. (Appendix A to definitive Proxy Statement, dated March 7, 2005, Commission File No. 1-16305).

** 10.40 Amendment No. 1 to 2005 Long-Term Incentive Plan of Puget Energy, Inc. (Exhibit 10.1 to the Current Report on Form 8-K, dated February 14, 2006, Commission File Nos. 1-16305 and 1-4393).

** 10.41 Employment agreement with S. P. Reynolds, Chief Executive Officer and President dated January 7, 2002 (Exhibit 10.104 to the Annual Report on Form 10-K for the fiscal year ended December 31, 2001, Commission File No. 1-16305 and 1-4393).

** 10.42 First Amendment dated May 10, 2005 to employment agreement with S.P. Reynolds, Chief Executive Officer and President, dated as of January 1, 2002 (Exhibit 10.3 to the Current Report on Form 8-K, dated May 12, 2005, Commission File Nos. 1-16305 and 1-4393).

** 10.43 Second Amendment dated February 9, 2006 to employment agreement with S. P. Reynolds, Chief Executive Officer and President, dated as of January 1, 2002 and amended as of May 10, 2005 (Exhibit 10.2 to the Current Report on Form 8-K, dated February 14, 2006, Commission File Nos. 1-16305 and 1-4393).

** 10.44 Restricted Stock Award Agreement with S. P. Reynolds, Chief Executive Officer and President, dated January 8, 2004 (Exhibit 10.90 to the Annual Report on Form 10-K for the fiscal year ended December 31, 2003, Commission File No. 1-16305 and 1-4393).

** 10.45 Restricted Stock Unit Award Agreement with S. P. Reynolds, Chief Executive Officer and President dated, January 8, 2004 (Exhibit 10.91 to the Annual Report on Form 10-K for the fiscal year ended December 31, 2003, Commission File No. 1-16305 and 1-4393).

** 10.46 Restricted Stock Award Agreement with S. P. Reynolds, Chief Executive Officer and President, dated January 8, 2002 (Exhibit 99.1 to Form S-8 Registration Statement, dated January 8, 2002, Commission File No. 333-76424).

** 10.47	Nonqualified Stock Option Grant Notice/Agreement with S. P. Reynolds, Chief Executive Officer and President dated March 11, 2002 (Exhibit 99.1 and Exhibit 99.2 to Form S-8 Registration Statement dated March 18, 2002, Commission File No. 333-84426).
** 10.48	Puget Sound Energy Amended and Restated Supplemental Executive Retirement Plan for Senior Management dated October 5, 2004. (Exhibit 10.55 to Annual Report on Form 10-K for fiscal year ended December 31, 2005, Commission File No. 1-16305 and 1-4393).
** 10.49	Puget Sound Energy Amended and Restated Deferred Compensation Plan for Key Employees dated January 1, 2003. (Exhibit 10.56 to Annual Report on Form 10-K for fiscal year ended December 31, 2005, Commission File No. 1-16305 and 1-4393).
** 10.50	Puget Sound Energy Amended and Restated Deferred Compensation Plan for Nonemployee Directors dated October 1, 2000. (Exhibit 10.57 to Annual Report on Form 10-K for fiscal year ended December 31, 2005, Commission File No. 1-16305 and 1-4393).
* 10.51	Summary of Director Compensation.
** 10.52	Performance-Based Restricted Stock Award Agreement with S.P. Reynolds, Chief Executive Officer and President, dated May 12, 2005 (Exhibit 10.4 to the Current Report on Form 8-K, dated May 12, 2005, Commission File Nos. 1-16305 and 1-4393).
** 10.53	Form of Amended and Restated Change of Control Agreement between Puget Sound Energy, Inc. and Executive Officers (Exhibit 10.3 to the Current Report on Form 8-K, dated February 14, 2006, Commission File Nos. 1-16305 and 1-4393).
** 10.54	Form of Performance-Based Restricted Stock Award Agreement between Puget Sound Energy and Key Employees (Exhibit 10.1 to the Current Report on Form 8-K, dated February 28, 2006, Commission File No. 1-16305).
* 10.55	Summary of Severance Benefit for B. A. Valdman, Senior Vice President Finance and Chief Financial Officer.
* 10.56	Restricted Stock Award Agreement with B.A Valdman, Senior Vice President Finance and Chief Financial Officer, dated December 4, 2003.
* 12.1	Statement setting forth computation of ratios of earnings to fixed charges of Puget Energy (2002 through 2006).
* 12.2	Statement setting forth computation of ratios of earnings to fixed charges of Puget Sound Energy (2002 through 2006).
* 21.1	Subsidiaries of Puget Energy.
* 21.2	Subsidiaries of PSE.
* 23.1	Consent of PricewaterhouseCoopers LLP.
* 31.1	Certification of Puget Energy - Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 – Stephen P. Reynolds.
* 31.2	Certification of Puget Energy - Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 – Bertrand A. Valdman.
* 31.3	Certification of Puget Sound Energy - Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 – Stephen P. Reynolds.
* 31.4	Certification of Puget Sound Energy – Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 – Bertrand A. Valdman.
* 32.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 – Stephen P. Reynolds.
* 32.2	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 – Bertrand A. Valdman.

* *Filed herewith.*

** *Management contract or compensating plan or arrangement.*