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, 2008**

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.**<br>A Washington Corporation<br>10885 NE 4th Street, Suite 1200<br>Bellevue, Washington 98004-5591<br>(425) 454-6363 | 91-1969407 |
| 1-4393 | **PUGET SOUND ENERGY, INC.**<br>A Washington Corporation<br>10885 NE 4th Street, Suite 1200<br>Bellevue, Washington 98004-5591<br>(425) 454-6363 | 91-0374630 |

*Securities registered pursuant to Section 12(b) of the Act:* *None*

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

| | TITLE OF EACH CLASS |
|---|---|
| **Puget Sound Energy, Inc.** | Preferred Stock (cumulative, $100 par value) |

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 | / / | No | /X/ | 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 | /X/ | No | / / | 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 | / / | No | /X/ | 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. /X/

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 | / / | Accelerated filer | / / | Non-accelerated filer | /X/ | Smaller reporting company | / / |
| Puget Sound Energy, Inc. | Large accelerated filer | / / | Accelerated filer | / / | Non-accelerated filer | /X/ | Smaller reporting company | / / |

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/ |

As of February 6, 2009, all of the outstanding shares of voting stock of Puget Energy, Inc. are held by Puget Equico LLC, an indirect wholly owned subsidiary of Puget Holdings LLC.

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

This Report on Form 10-K is a combined report being filed separately by: 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.

# INDEX

## DEFINITIONS

| | |
|---|---|
| ALJ | Administrative Law Judge |
| AFUDC | Allowance for Funds Used During Construction |
| aMW | Average Megawatt |
| BPA | Bonneville Power Administration |
| CAISO | California Independent System Operator |
| Colstrip | Colstrip, Montana coal-fired steam electric generation facility |
| Consortium | Infrastructure investors led by Macquarie Infrastructure Partners I, the Canada Pension Plan Investment Board and British Columbia Investment Management Corporation, and also includes Alberta Investment Management Corporation, Macquarie-FSS Infrastructure Trust, Macquarie Infrastructure Partners II and Macquarie Capital Group Limited |
| Dth | Dekatherm (one Dth is equal to one MMBtu) |
| EITF | Emerging Issues Task Force |
| EPA | United States Environmental Protection Agency |
| ERO | Electric Reliability Organization |
| FASB | Financial Accounting Standards Board |
| FERC | Federal Energy Regulatory Commission |
| FIN | Financial Accounting Standards Board Interpretation |
| FPA | Federal Power Act |
| GAAP | Generally Accepted Accounting Principles |
| GHG | Greenhouse gases |
| Goldendale | Goldendale electric generating facility |
| InfrastruX | InfrastruX Group, Inc. |
| IRP | Integrated Resource Plan |
| IRS | Internal Revenue Service |
| ISO | Independent System Operator |
| kWh | Kilowatt Hour (one kWh equals one thousand watt hours) |
| LIBOR | London Interbank Offered Rate |
| LNG | Liquefied Natural Gas |
| Mint Farm | Mint Farm Energy Center |
| 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) |
| NERC | North American Electric Reliability Corporation |
| Ninth Circuit | United States Court of Appeals for the Ninth Circuit |
| NPNS | Normal Purchase Normal Sale |
| NWP | Northwest Pipeline GP |

| | |
|---|---|
| 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. |
| PTC | Production Tax Credit |
| PUDs | Washington Public Utility Districts |
| Puget Energy | Puget Energy, Inc. |
| Puget Equico | Puget Equico LLC |
| Puget Holdings | Puget Holdings LLC |
| PURPA | Public Utility Regulatory Policies Act |
| REP | Residential Exchange Program |
| 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 |
| WECC | Western Electricity Coordinating Council |
| WECO | Western Energy Company |
| Wild Horse | Wild Horse wind project |

## FORWARD-LOOKING STATEMENTS

Puget Energy, Inc. (Puget Energy) and Puget Sound Energy, Inc. (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. However, 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, financings, 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, maintenance, construction and operation of natural gas and electric distribution and transmission facilities (natural gas and electric), licensing of hydroelectric operations and natural gas storage facilities, recovery of other capital investments, recovery of power and natural gas costs, recovery of regulatory assets and present or prospective wholesale and retail competition;
- Failure to comply with FERC or Washington Commission standards and/or rules, which could result in penalties based on the discretion of either commission;
- Failure to comply with electric reliability standards developed by the North American Electric Reliability Corporation (NERC) for users, owners and operators of the power system, which could result in penalties of up to $1.0 million per day per violation;
- 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 costs arising from changes in enacted federal, state or local tax laws through revenue in a timely manner;
- Changes in tax law, related regulations, or differing interpretation or enforcement of applicable law by the Internal Revenue Service (IRS) or other taxing jurisdiction;
- Natural disasters, such as hurricanes, windstorms, earthquakes, floods, fires and landslides, which can interrupt service and/or cause temporary supply disruptions and/or price spikes in the cost of fuel and raw materials and impose extraordinary costs;
- Commodity price risks associated with procuring natural gas and power in wholesale markets;
- 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 its suppliers;
- The effect of wholesale market structures (including, but not limited to, regional market designs or transmission organizations) or other related federal initiatives;
- PSE electric or natural 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;
- Weather, which can have a potentially serious impact on PSE’s ability to procure adequate supplies of natural 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 a natural gas or electric plant to operate as intended;
- The ability to renew contracts for electric and natural 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 and generating facilities;
- The ability to restart generation following a regional transmission disruption;
- The failure of the interstate natural gas pipeline delivering to PSE's system, which may impact PSE's ability to adequately deliver natural gas supply or electric power 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 or the condemnation of PSE's facilities, which may result in changes in demand for PSE's services;
- The failure of information systems or the failure to secure information system data which may impact the operations and cost of PSE's customer service, generation, distribution and transmission;
- The impact of acts of God, terrorism, flu pandemic or similar significant events;
- Capital market conditions, including changes in the availability of capital and 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 insurance coverage and the cost of such insurance;
- The ability to maintain effective internal controls over financial reporting and operational processes;
- Changes in PSE's, and its parent Puget Energy's credit ratings, which may have an adverse impact on the availability and cost of capital for PSE or Puget Energy;
- Deteriorating values of the equity, fixed income and other markets which could significantly impact the value of investments of PSE's retirement plan and post-retirement medical trusts and the funding of obligations thereunder; and
- The effects related to the completion of the merger on February 6, 2009 on Puget Energy's and PSE's business relationships, operating results and business generally, including PSE's ability to retain key employees.

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 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 February 6, 2009, Puget Holdings LLC (Puget Holdings) completed its merger with Puget Energy. Puget Holdings is a consortium of long-term infrastructure investors led by Macquarie Infrastructure Partners I, Macquarie Capital Group Limited, the Canada Pension Plan Investment Board and British Columbia Investment Management Corporation, and also includes Alberta Investment Management Corporation, Macquarie-FSS Infrastructure Trust and Macquarie Infrastructure Partners II (collectively, the Consortium). At the time of the merger, each issued and outstanding share of common stock of Puget Energy, other than any shares in respect of which dissenter's rights are perfected and other than any shares owned by the Consortium, were cancelled and converted automatically into the right to receive $30.00 in cash, without interest. As a result of the merger, Puget Energy is the direct wholly owned subsidiary of Puget Equico LLC (Puget Equico), which is an indirect wholly owned subsidiary of Puget Holdings.

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** | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2008 | 2007 | 2006 | 2008 | 2007 | 2006 | 2008 | 2007 | 2006 |
| Puget Sound Energy | 99.8% | 99.6% | 99.7% | 102.9 % | 99.7% | 103.3 % | 99.0% | 98.9% | 99.0% |
| Other[1] | 0.2% | 0.4% | 0.3% | (2.9)% | 0.3% | (3.3)% | 1.0% | 1.1% | 1.0% |

1 *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 direct parent company of PSE, the oldest and 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 distribution. Puget Energy's business strategy is to generate stable earnings and cash flow by offering reliable electric and natural 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 natural 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, 2008, PSE had approximately 1,069,400 electric customers, consisting of 943,800 residential, 118,500 commercial, 3,700 industrial and 3,400 other customers; and approximately 743,800 natural gas customers, consisting of 686,700 residential, 54,400 commercial, 2,600 industrial and 100 transportation customers. At December 31, 2008, approximately 370,100 customers purchased both electricity and natural gas from PSE. In 2008, PSE added approximately 13,000 electric customers and 14,300 natural gas customers, representing annualized customer growth rates of 1.2% and 2.0% respectively. During 2008, PSE's billed retail and transportation revenues from electric utility operations were derived 53.2% from residential customers, 40.3% from commercial customers, 5.3% from industrial customers and 1.2% from other customers. PSE's retail revenues from natural gas utility operations were derived 63.0% from residential customers, 30.7% from commercial customers, 3.6% from industrial customers and 2.7% from transportation customers in 2008. During this period the largest customer accounted for approximately 1.3% 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 natural gas rates to recover variations in natural gas supply and transportation costs. PSE also has a Power Cost Adjustment (PCA) mechanism in retail electric rates to recover variations in electricity costs on a shared basis with customers.

In the five-year period ended December 31, 2008, PSE's gross electric utility plant additions were $2.8 billion and retirements were $350.3 million. In the same five-year period, PSE's gross gas utility plant additions were $842.2 million and retirements were $94.5 million. In the same five-year period, PSE's gross common utility plant additions were $201.2 million and retirements were $44.4 million. Gross electric utility plant at December 31, 2008 was approximately $6.6 billion, which consisted of 48.0% distribution, 35.2% generation, 5.3% transmission and 11.5% general plant and other. Gross gas utility plant at December 31, 2008 was approximately $2.5 billion, which consisted of 90.7% distribution and 9.3% general plant and other. Gross common utility general and intangible plant at December 31, 2008 was approximately $550.4 million.

### EMPLOYEES

At February 20, 2009, Puget Energy had no employees and PSE had approximately 2,800 full-time employees. Approximately 1,285 PSE employees are represented by the International Brotherhood of Electrical Workers Union (IBEW) and the United Association of Plumbers and Pipefitters (UA). The current labor contracts with the IBEW and UA expire March 31, 2010 and September 30, 2010, respectively.

### 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.

## 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 sale 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 continues to work with the Bonneville Power Administration (BPA) and other regional transmission owners to address the transmission related issues in the region via an organization known as ColumbiaGrid.

The Energy Policy Act of 2005 required 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. On March 16, 2007, FERC issued Order 693, "Mandatory Reliability Standards for the Bulk-Power System," which sets such standards and imposes penalties of up to $1.0 million per day per violation for failure to comply. FERC has approved 83 reliability standards developed by NERC. The 83 standards comprise 586 requirements and sub-requirements. On June 18, 2007, the standards became mandatory and enforceable under federal law. PSE must comply with the standards and requirements that apply to the NERC functions for which PSE has registered. Additional standards continue to be developed by NERC and will be adopted in coming months or years. PSE expects that the existing standards will change often as a result of modifications, guidance and clarification following industry implementation and ongoing audits and enforcement.

Electric reliability standards adopted by FERC, NERC and/or the Western Electricity Coordinating Council (WECC) include periodic self-certifications of compliance, self-reports of violations after discovery of the violation, spot checks to review self-certifications and external audits that review compliance with designated standards. In accordance with the Compliance Monitoring Enforcement Program process, PSE self-reports violations when they are discovered. Such self-reports could result in settlement of issues without a penalty or issuances of penalties in the future.

**STATE REGULATION**

PSE's retail electric and natural gas services are regulated by the Washington Commission. PSE provides natural gas transportation as a separate service to industrial and commercial customers who choose to purchase their natural gas supply directly from producers and/or natural gas marketers. PSE is not aware of any proposals or prospects for retail deregulation in the state of Washington.

**ELECTRIC REGULATION AND RATES**

**Power Cost Adjustment Mechanism.** In 2002, the Washington Commission approved a PCA mechanism. The PCA mechanism will trigger if PSE's costs to provide customers' electricity varies from a baseline power cost rate established in a rate proceeding. 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 | CUSTOMERS' SHARE | COMPANY'S SHARE |
|---|---|---|
| +/- $20 million | 0 % | 100 % |
| +/- $20 - $40 million | 50 % | 50 % |
| +/- $40 - $120 million | 90 % | 10 % |
| +/- $120 million | 95 % | 5 % |

**Electric General Rate Case.** On October 8, 2008, the Washington Commission issued its order in PSE's electric general rate case filed in December 2007, approving a general rate increase for electric customers of $130.2 million or 7.1% annually. The rate increase for electric customers was effective November 1, 2008. In its order, the Washington Commission approved a weighted cost of capital of 8.25%, or 7.00% after-tax, and a capital structure that included 46.0% common equity with a return on equity of 10.15%.

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 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%. On June 28, 2006, the Washington Commission approved 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 called a PCORC was approved in 2002 by the Washington Commission to periodically reset power cost rates and provide for timely review of new resource acquisition costs and inclusion of such costs in rates. On January 15, 2009, the Washington Commission issued an order that authorized the continuation of the PCORC with certain modifications to which the Washington Commission staff and the Company agree. The five procedural modifications to the PCORC include extending the expected procedural schedule from five to six months, limiting the power cost updates to one per PCORC unless an additional update is allowed by the Washington Commission as part of the compliance filing, prohibiting the overlap of PCORC and general rate cases (except for requests for interim rate relief), shortening data request time from ten to five business days and requiring the Company to provide its future energy resource model projections at the outset of a case.

On August 2, 2007, the Washington Commission approved the PCORC settlement agreement and authorized an increase in PSE's electric rates of $64.7 million or an average increase of 3.7% annually effective September 1, 2007. PSE's investment in the Goldendale electric generating facility (Goldendale) acquired in February 2007 was found prudent, thus allowing for recovery of certain ownership and operating costs through electric retail rates effective September 1, 2007 along with updating other power costs.

**Accounting Petitions.** On April 11, 2007, the Washington Commission issued an accounting order that authorized PSE to defer certain ownership and operating costs (and associated carrying costs) related to its purchase of Goldendale during the period prior to inclusion in PSE's retail electric rates in the PCORC. The deferral was for the time period from March 15, 2007 through September 1, 2007, at which time PSE began recovering Goldendale ownership and operation costs in electric rates. As of December 31, 2008, PSE had established a regulatory asset of $11.8 million. Recovery of these costs over three years began November 2008 as allowed in the October 2008 general rate case order.

On May 21, 2008, PSE filed an accounting petition for a Washington Commission order authorizing the deferral of a settlement payment of $10.7 million incurred as a result of the recent settlement of a lawsuit in the state of Montana over alleged damages caused by the operation of the Colstrip, Montana coal-fired steam electric generation facility (Colstrip).

On May 28, 2008, the Washington Commission authorized PSE to defer a maximum of $2.3 million of costs associated with FERC-required studies of Baker River Dam. The accounting petition allows PSE to defer costs incurred from January 8, 2007 through December 31, 2010.

On November 5, 2008, PSE filed an accounting petition for a Washington Commission order authorizing the deferral and recovery of interest due the Internal Revenue Service (IRS) for tax years 2001 to 2006 along with carrying costs incurred in connection with the interest due. In October 2005, the Washington Commission issued an order authorizing the deferral and recovery of costs associated with increased borrowings necessary to remit deferred taxes to the IRS.

On November 6, 2008, PSE filed an accounting petition for a Washington Commission order authorizing accounting treatment and amortization related to payments received for taking assignment of Westcoast Pipeline Capacity which is intended to be used in PSE's natural gas business. The accounting petition seeks deferred accounting treatment and amortization of the regulatory liability to power costs beginning in November 2009 and extending over the remaining primary term of the pipeline capacity contract through October 31, 2018.

On November 15, 2008, PSE filed an accounting petition for a Washington Commission order determining that its newly acquired Mint Farm Energy Center (Mint Farm) complies with the Washington State greenhouse gases (GHG) emissions performance standard. Under this standard PSE can defer the costs associated with Mint Farm until the cost of the plant is included in rates. PSE is currently deferring both variable and fixed costs as allowed. The Mint Farm purchase was completed on December 5, 2008. On December 23, 2008, the Washington Commission set this matter for hearing. PSE expects to receive an order by the third quarter 2009.

PSE's wind generating facilities are eligible for Federal Production Tax Credits (PTCs) that will offset some of the costs associated with generating power. 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 $0.021 per kilowatt hour (kWh) for wind generation and may be subject to inflation adjustments over time. The tax credit can be claimed for ten years for a new wind project put into service prior to January 1, 2013. The credit may be used to offset up to 75.0% of current taxes payable but it may not reduce current taxes below the alternative minimum tax. Unused credits may be carried back one year or carried forward up to 20 years. PSE has a tariff schedule which passes the benefits of the PTCs to customers based on estimated generation of the PTC credits. PSE may adjust the PTC tariff annually based on differences between the PTC credits provided to the customers and the PTC credits actually earned, plus estimated PTC credits for the following year, less interest associated with the deferred tax balance for the PTC credits. The tariff is not subject to the sharing bands in the PCA. Since customers receive 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 for its carrying costs for funds through this calculation.

### GAS REGULATION AND RATES

**Gas General Rate Case.** On October 8, 2008, the Washington Commission issued its order in PSE's natural gas general rate case filed in December 2007, approving a natural gas rate increase of $49.2 million or 4.6% annually. The rate increases for natural gas customers were effective November 1, 2008. In its order, the Washington Commission approved a weighted cost of capital of 8.25%, or 7.00% after-tax, and a capital structure that included 46.0% common equity with a return on equity of 10.15%.

On January 5, 2007, the Washington Commission issued its order in PSE's natural gas general rate case, granting an increase in natural gas rates of $29.5 million or 2.8% annually, effective January 13, 2007, which resulted in an increase in natural gas margin of approximately 9.8% annually. 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 PGA mechanism in retail natural gas rates to recover variations in natural gas supply and transportation costs. Variations in natural gas rates are passed through to customers, therefore PSE's natural gas margin and net income are not affected by such variations. On September 25, 2008, the Washington Commission approved PSE's requested revisions to its PGA tariff schedules resulting in an increase of $108.8 million or 11.1% on an annual basis in gas sales revenues effective October 1, 2008. The rate increase was the result of higher costs of natural gas in the forward market and a reduction of the credit for the accumulated PGA payable balance. The PGA rate change will increase PSE's revenue but will not impact the Company's net income as the increased revenue will be offset by increased purchased gas and gas transportation costs.

The following rate adjustments were approved by the Washington Commission in relation to the PGA mechanism during 2008, 2007 and 2006:

| Effective Date | Percentage Increase (Decrease) in Rates | Annual Increase (Decrease) in Revenues (Dollars In Millions) |
|---|---|---|
| October 1, 2008 | 11.1 % | $ 108.8 |
| October 1, 2007 | (13.0)% | (148.1) |
| October 1, 2006 | 10.2 % | 95.1 |

**ELECTRIC UTILITY OPERATING STATISTICS**

| Twelve Months ended December 31 | 2008 | 2007 | 2006 |
|---|---|---|---|
| Generation and purchased power, MWh | | | |
| Company-controlled resources | 9,419,375 | 8,623,094 | 6,845,323 |
| Contracted resources | 8,711,075 | 9,353,824 | 9,625,381 |
| Non-firm energy purchased | 7,106,320 | 7,473,458 | 8,185,198 |
| Total generation and purchased power | 25,236,770 | 25,450,376 | 24,655,902 |
| Less: losses and Company use | (1,549,277) | (1,562,975) | (1,489,008) |
| Total energy sales, MWh | 23,687,493 | 23,887,401 | 23,166,894 |

| Twelve Months ended December 31 | 2008 | 2007 | 2006 |
|---|---|---|---|
| Electric energy sales, MWh | | | |
| Residential | 11,082,670 | 10,869,347 | 10,593,340 |
| Commercial | 9,453,940 | 9,226,215 | 8,939,155 |
| Industrial | 1,304,662 | 1,364,264 | 1,368,672 |
| Other customers | 100,948 | 96,217 | 78,078 |
| Total energy billed to customers | 21,942,220 | 21,556,043 | 20,979,245 |
| Unbilled energy sales – net increase | 80,375 | 78,303 | 119,800 |
| Total energy sales to customers | 22,022,595 | 21,634,346 | 21,099,045 |
| Sales to other utilities and marketers | 1,664,898 | 2,253,055 | 2,067,849 |
| Total energy sales, MWh | 23,687,493 | 23,887,401 | 23,166,894 |
| Transportation, including unbilled | 2,045,161 | 2,131,970 | 2,091,981 |
| Electric energy sales and transportation, MWh | 25,732,654 | 26,019,371 | 25,258,875 |

| Twelve Months ended December 31 | 2008 | 2007 | 2006 |
|---|---|---|---|
| Electric operating revenues by classes (thousands): | | | |
| Residential | $ 1,046,897 | $ 951,101 | $ 788,237 |
| Commercial | 800,879 | 748,824 | 702,754 |
| Industrial | 106,092 | 105,227 | 103,043 |
| Other customers | 72,250 | 57,482 | 66,470 |
| Operating revenues billed to customers | 2,026,118 | 1,862,634 | 1,660,504 |
| Unbilled revenues – net increase | 10,789 | 16,103 | 20,749 |
| Total operating revenues from customers | 2,036,907 | 1,878,737 | 1,681,253 |
| Transportation, including unbilled | 7,840 | 9,356 | 11,488 |
| Sales to other utilities and marketers | 84,716 | 109,736 | 85,004 |
| Total electric operating revenues | $ 2,129,463 | $ 1,997,829 | $ 1,777,745 |

| TWELVE MONTHS ENDED DECEMBER 31 | 2008 | 2007 | 2006 |
|---|---|---|---|
| Number of customers served (average): | | | |
| Residential | 939,440 | 926,080 | 909,876 |
| Commercial | 117,521 | 115,577 | 111,672 |
| Industrial | 3,744 | 3,771 | 3,696 |
| Other | 3,231 | 2,965 | 2,637 |
| Transportation | 18 | 18 | 18 |
| Total customers | 1,063,954 | 1,048,411 | 1,027,899 |

| TWELVE MONTHS ENDED DECEMBER 31 | 2008 | 2007 | 2006 |
|---|---|---|---|
| Average kWh used per customer: | | | |
| Residential | 11,797 | 11,737 | 11,643 |
| Commercial | 80,445 | 79,827 | 80,048 |
| Industrial | 348,468 | 361,778 | 370,312 |
| Other | 31,243 | 32,451 | 29,609 |
| Average revenue billed per customer: | | | |
| Residential | $ 1,114 | $ 1,027 | $ 866 |
| Commercial | 6,815 | 6,479 | 6,293 |
| Industrial | 28,337 | 27,904 | 27,880 |
| Other | 22,362 | 19,366 | 25,207 |
| Average retail revenues per kWh sold: | | | |
| Residential | $ 0.0945 | $ 0.0875 | $ 0.0744 |
| Commercial | 0.0847 | 0.0812 | 0.0786 |
| Industrial | 0.0813 | 0.0771 | 0.0753 |
| Average retail revenue per kWh sold | 0.0895 | 0.0841 | 0.0763 |
| Heating degree days | 5,062 | 4,823 | 4,476 |
| Percent of normal – NOAA 30-year average | 105.1% | 100.5% | 93.3% |
| Load factor[1] | 58.6% | 58.9% | 52.4% |

[1] *Average usage by customers divided by their maximum usage.*

**ELECTRIC SUPPLY**

At December 31, 2008, PSE's electric power resources had a total capacity of approximately 5,077 megawatts (MW). PSE's historical peak load of approximately 4,906 MW occurred on December 15, 2008. 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. 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 and energy production during the year at December 31, 2008 and 2007:

| | Peak Power Resources At December 31 | | | | Energy Production At December 31 | | | |
|---|---|---|---|---|---|---|---|---|
| | 2008 | | 2007 | | 2008 | | 2007 | |
| | MW | % | MW | % | MWh | % | MWh | % |
| Purchased resources: | | | | | | | | |
| Columbia River PUD contracts[1] | 1,135 | 22.4% | 1,073 | 22.7% | 5,438,195 | 21.5% | 5,810,416 | 22.8% |
| Other hydroelectric[2] | 145 | 2.8% | 168 | 3.6% | 592,535 | 2.3% | 570,639 | 2.2% |
| Other producers[2] | 821 | 16.2% | 944 | 20.0% | 2,532,033 | 10.0% | 2,964,199 | 11.6% |
| Wind | 50 | 1.0% | 50 | 1.1% | 148,311 | 0.6% | 8,570 | 0.2% |
| Short-term wholesale energy purchases[3] | N/A | N/A | N/A | N/A | 7,106,322 | 28.2% | 7,473,458 | 29.4% |
| Total purchased | 2,151 | 42.4% | 2,235 | 47.4% | 15,817,396 | 62.6% | 16,827,282 | 66.2% |
| Company-controlled resources: | | | | | | | | |
| Hydroelectric | 236 | 4.6% | 236 | 5.0% | 974,924 | 3.9% | 1,154,234 | 4.5% |
| Coal | 677 | 13.3% | 677 | 14.3% | 5,067,445 | 20.1% | 5,142,912 | 20.2% |
| Natural gas/oil[4] | 1,627 | 32.1% | 1,192 | 25.3% | 2,269,586 | 9.0% | 1,310,625 | 5.1% |
| Wind | 386 | 7.6% | 379 | 8.0% | 1,107,419 | 4.4% | 1,015,323 | 4.0% |
| Total company-controlled | 2,926 | 57.6% | 2,484 | 52.6% | 9,419,374 | 37.4% | 8,623,094 | 33.8% |
| Total | 5,077 | 100.0% | 4,719 | 100.0% | 25,236,770 | 100.0% | 25,450,376 | 100.0% |

1 *Net of 59 MW of capacity delivered to Canada pursuant to the provisions of a treaty between Canada and the United States and Canadian Entitlement Allocation agreements.*

2 *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.*

3 *Short-term wholesale purchases net of resale of 1,664,898 MWh and 2,253,055 MWh account for 23.1% and 22.5% of energy production for 2008 and 2007, respectively.*

4 *Goldendale is included beginning February 2007, Sumas is included beginning August 2008 and Mint Farm is included beginning December 2008.*

### Integrated Resource Plans

PSE is required by the Washington Commission to file electric and natural gas Integrated Resource Plans (IRP) every two years. PSE filed its most recent IRP on May 30, 2007 with the Washington Commission. The IRP demonstrated PSE's continuing need to acquire significant amounts of new generating resources, driven primarily by expiration of existing purchase power contracts. Capacity needs in the plan were identified as:

| | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|
| Projected MW shortfall | 200 | 800 | 1,300 | 1,400 |

To meet these expected shortfalls, the plan supports a strategy of significantly increasing energy efficiency programs, pursuing additional renewable resources (primarily wind) and additional natural gas-fired generation to meet the growing needs of customers. The actual resources acquired and ownership structure of such resources will be determined through the Company's resource acquisition program that examines individual specific acquisition and development opportunities.

In May 2009, PSE will file another IRP. Within 135 days of this filing, PSE plans to file a request for proposal with the Washington Commission that will be used to solicit proposals to continue expansion of its energy-efficiency programs and acquisition of power supplies.

### Electric Resource Acquisitions

On July 28, 2008, PSE completed the purchase of the 125 MW Sumas cogeneration power plant located in PSE's service territory. On December 5, 2008, PSE completed the purchase of the 310 MW Mint Farm natural gas-fired power plant, which is located in Longview, Washington, for approximately $240.0 million. In addition, PSE began expansion of the Company's existing 229 MW Wild Horse wind project (Wild Horse) to include an additional 44 MW of wind generating capacity. The expansion is expected to be completed by December 2009 at an estimated cost of $107.5 million. These acquisitions are part of PSE's long-range plan to meet its customers' steadily growing electricity needs and statutory mandates regarding PSE's energy resource portfolio.

On December 5, 2008, PSE purchased a 50.0% undivided interest in four proposed development-stage wind projects totaling 1,300 MW in Columbia and Garfield counties in Washington State from RES America, Inc. This joint effort to further develop these projects is part of PSE's long-range initiative for meeting its customers' growing electricity needs as well as providing PSE with a portfolio of environmentally acceptable energy options.

**COMPANY – CONTROLLED ELECTRIC GENERATION RESOURCES**

At December 31, 2008, PSE owns or controls the following plants with an aggregate net generating capacity of 2,926 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 |
| Fredonia Units 3 & 4 | Dual-fuel combustion turbines | 107 | 2001 |
| Frederickson Units 1 & 2 | Dual-fuel combustion turbines | 147 | 1981 |
| Whitehorn Units 2 & 3 | Dual-fuel combustion turbines | 147 | 1981 |
| Frederickson Unit 1 (49.85% interest) | Natural gas combined cycle | 137 | Added duct firing in 2005 |
| Goldendale | Natural gas combined cycle | 277 | 2004 |
| Mint Farm | Natural gas combined cycle | 310 | 2007 |
| Sumas | Natural gas cogeneration | 125 | 1993 |
| 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 | 157 | 2005; added 4 turbines in 2008 |
| Total net capacity | | 2,926 | |

**FERC HYDROELECTRIC PROJECTS AND LICENSES**

PSE is required to obtain operating licenses from FERC for all but one of its hydroelectric generating plants. The Baker River and Snoqualmie Falls projects operate pursuant to licenses issued by FERC. A typical license contains mandatory conditions of operation, such as flow rate requirements, adherence to certain ramping protocols, maintenance of reservoir levels, equipment upgrade projects, recreation requirements and fish and wildlife mitigation projects for a 30 to 50 year period. Licenses to operate hydroelectric plants balance conflicting interests of numerous governmental, non-governmental and private parties and address issues that may include environmental compliance, fish protection and mitigation, water quality, Native American rights, title claims, operational and capital improvements and flood control. FERC also regulates dam safety and administers proceedings under the Federal Power Act (FPA) to license jurisdictional hydropower projects.

**Baker River project.** On October 17, 2008, FERC issued a new license for the Baker River hydroelectric project for a 50-year term. The new license incorporates the measures proposed in the comprehensive Settlement Agreement that was filed on November 30, 2004 and signed by PSE and 23 parties (federal, state and local governmental organizations, Native American Indian tribes, environmental and other non-governmental entities). The new license will require net present value funds of between $350.0 million to $370.0 million (capital expenditures and operations and maintenance cost) over 50 years in order to implement the license conditions. The license provides protection and enhancements for fish and wildlife, water quality, recreation and cultural and historic resources.

**Snoqualmie Falls project.** The Snoqualmie Falls project was granted a new 40-year operating license by FERC on June 29, 2004. On December 6, 2007, PSE filed an application for a non-capacity amendment to the 2004 license. The application seeks to amend the license to account for technology improvements and hydrologic and other changes that occurred post-license. The ultimate outcome of the license amendment application remains uncertain.

**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 water rights associated with the project. In April of 2008, PSE entered into a purchase and sale agreement with Cascade Water Alliance for the transfer of certain project assets, including water rights, the diversion dam, the flow line, the reservoir, the powerhouse, the tailrace and associated real property. Contingencies to closing have not yet been satisfied. PSE is also considering the sale of other surplus project lands.

In 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 project and any sales proceeds are known. At December 31, 2008, the net utility plant being recovered in electric rates is $40.3 million. Recovery of the remaining costs of $30.7 million will be determined in a future general rate case after completion of all property sales. 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 2008, approximately 21.5% of PSE's energy output was obtained through long-term contracts with several of the Washington Public Utility Districts (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, 2008, the Company was entitled to purchase portions of the power output of the PUDs' projects as set forth below:

| | | | Company's Annual Amount Purchasable (Approximate) | |
|---|---|---|---|---|
| Project | Contract Exp. Year | License Exp. Year | % of Output | Megawatt Capacity |
| Chelan County PUD:[1] | | | | |
| Rock Island Project | 2031 | 2029 | 50.0 | 312 |
| Rocky Reach Project | 2031 | TBD | 38.9 | 498 |
| Douglas County PUD: | | | | |
| Wells Project | 2018 | 2012 | 29.9 | 231 |
| Grant County PUD:[2,3] | | | | |
| Priest Rapids Development | 2052 | 2052 | 4.3 | 41 |
| Wanapum Development | 2052 | 2052 | 10.8 | 112 |
| Total | | | | 1,194 |

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 hydroelectric generating facilities located on the mid-Columbia River in exchange for PSE paying 25.0% of the operating costs of the facilities. 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 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 generally is not obligated to make payments under these contracts unless power is delivered.

Under a 1985 settlement agreement with BPA, PSE is entitled to receive exchange energy from BPA during the months of November through April, which amounts to 42 average megawatts (aMW) of energy and 82 MW of capacity for contract year 2007-2008. BPA has an option to request that PSE deliver up to 42 aMW of exchange energy to BPA in all months except May, July and August for contract year 2007-2008. 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, now NorthWestern Energy, for 71 aMW 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.

**ELECTRIC ENERGY SUPPLY CONTRACTS AND AGREEMENTS WITH NON-UTILITY GENERATORS**

As required by the federal Public Utility Regulatory Policies Act (PURPA), PSE entered into long-term firm purchased power contracts with non-utility generators. PSE purchases the net electrical output of these 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, 2008, the Company purchased the power output from the following entities:

| CONTRACT | PLANT TYPE | CONTRACT EXP. YEAR | MEGAWATT CAPACITY | AVERAGE MEGAWATTS OF ENERGY |
|---|---|---|---|---|
| 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 | | | 385 | 339 |

**ELECTRIC TRANSMISSION CONTRACTS WITH OTHER UTILITIES**

PSE has entered into multiple 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. These transmission costs are recovered through the PCA mechanism.

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

The transmission agreements with BPA have various terms and collectively have an aggregate demand limit in excess of 3,930 MW.

**NATURAL GAS UTILITY OPERATING STATISTICS**

| TWELVE MONTHS ENDED DECEMBER 31 | 2008 | 2007 | 2006 |
|---|---|---|---|
| Gas operating revenues by classes (thousands): | | | |
| Residential | $ 766,799 | $ 756,188 | $ 697,631 |
| Commercial firm | 321,829 | 306,357 | 279,977 |
| Industrial firm | 42,530 | 46,805 | 43,994 |
| Interruptible | 53,317 | 67,560 | 68,753 |
| Total retail gas sales | 1,184,475 | 1,176,910 | 1,090,355 |
| Transportation services | 14,700 | 13,706 | 13,269 |
| Other | 17,694 | 17,413 | 16,494 |
| Total gas operating revenues | $ 1,216,869 | $ 1,208,029 | $ 1,120,118 |

| TWELVE MONTHS ENDED DECEMBER 31 | 2008 | 2007 | 2006 |
|---|---|---|---|
| Number of customers served (average): | | | |
| Residential | 681,267 | 666,756 | 649,373 |
| Commercial firm | 53,441 | 52,067 | 51,007 |
| Industrial firm | 2,596 | 2,611 | 2,618 |
| Interruptible | 419 | 445 | 470 |
| Transportation | 128 | 124 | 122 |
| Total customers | 737,851 | 722,003 | 703,590 |

| TWELVE MONTHS ENDED DECEMBER 31 | 2008 | 2007 | 2006 |
|---|---|---|---|
| Gas volumes, therms (thousands): | | | |
| Residential | 589,405 | 556,837 | 533,370 |
| Commercial firm | 275,631 | 248,497 | 236,753 |
| Industrial firm | 38,956 | 40,472 | 41,185 |
| Interruptible | 56,329 | 64,944 | 65,016 |
| Total retail gas volumes, therms | 960,321 | 910,750 | 876,324 |
| Transportation volumes | 217,774 | 213,542 | 206,367 |
| Total volumes | 1,178,095 | 1,124,292 | 1,082,691 |

| TWELVE MONTHS ENDED DECEMBER 31 | 2008 | 2007 | 2006 |
|---|---|---|---|
| Working gas volumes in storage at year end, therms (thousands): | | | |
| Jackson Prairie | 60,301 | 64,982 | 68,141 |
| AECO hub - Canada | -- | 15,093 | 14,810 |
| Clay Basin | 92,203 | 87,454 | 91,090 |
| Average therms used per customer: | | | |
| Residential | 865 | 835 | 821 |
| Commercial firm | 5,158 | 4,773 | 4,642 |
| Industrial firm | 15,006 | 15,501 | 15,731 |
| Interruptible | 134,436 | 145,942 | 138,332 |
| Transportation | 1,701,359 | 1,722,113 | 1,691,533 |
| Average revenue per customer: | | | |
| Residential | $ 1,126 | $ 1,134 | $ 1,074 |
| Commercial firm | 6,022 | 5,884 | 5,489 |
| Industrial firm | 16,383 | 17,926 | 16,804 |
| Interruptible | 127,247 | 151,819 | 146,283 |
| Transportation | 114,846 | 110,533 | 108,762 |
| Average revenue per therm sold: | | | |
| Residential | $ 1.301 | $ 1.358 | $ 1.308 |
| Commercial firm | 1.168 | 1.233 | 1.183 |
| Industrial firm | 1.092 | 1.156 | 1.068 |
| Interruptible | 0.947 | 1.040 | 1.057 |
| Average retail revenue per therm sold | 1.233 | 1.292 | 1.244 |
| Transportation | 0.068 | 0.064 | 0.064 |
| Heating degree days | 5,062 | 4,823 | 4,476 |
| Percent of normal – NOAA 30-year average | 105.1 % | 100.5 % | 93.3 % |

## NATURAL GAS SUPPLY FOR NATURAL GAS CUSTOMERS

PSE currently purchases a portfolio of natural 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 natural gas to serve its customers. All of PSE's natural gas supply is ultimately transported through the facilities of Northwest Pipeline GP (NWP), the sole interstate pipeline delivering directly into PSE's service territory. Delivery of gas supply to PSE's natural gas system is therefore dependent upon the operations of NWP.

| | 2008 | | 2007 | |
|---|---|---|---|---|
| PEAK FIRM NATURAL GAS SUPPLY AT DECEMBER 31 | Dth per Day | % | Dth per Day | % |
| Purchased gas supply: | | | | |
| British Columbia | 180,000 | 19.7% | 204,500 | 23.0% |
| Alberta | 75,000 | 8.2% | 60,000 | 6.7% |
| United States | 153,100 | 16.8% | 110,800 | 12.4% |
| Total purchased natural gas supply | 408,100 | 44.7% | 375,300 | 42.1% |
| Purchased storage capacity: | | | | |
| Clay Basin | 24,000 | 2.6% | 66,200 | 7.4% |
| Jackson Prairie | 48,400 | 5.3% | 55,100 | 6.2% |
| AECO hub - Canada | -- | 0.0% | 16,700 | 1.9% |
| Liquefied natural gas | 70,500 | 7.8% | 70,500 | 7.9% |
| Total purchased storage capacity | 142,900 | 15.7% | 208,500 | 23.4% |
| Owned storage capacity: | | | | |
| Jackson Prairie | 348,700 | 38.2% | 294,700 | 33.1% |
| Propane-air and other | 12,500 | 1.4% | 12,500 | 1.4% |
| Total owned storage capacity | 361,200 | 39.6% | 307,200 | 34.5% |
| Total peak firm natural gas supply | 912,200 | 100.0% | 891,000 | 100.0% |
| Other and commitments with third parties | (16,900) | | (40,400) | |
| Total net peak firm natural gas supply | 895,300 | | 850,600 | |

*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 natural gas held in NWP's liquefied natural gas (LNG) facility at Plymouth, Washington; by using PSE-owned natural gas held in PSE's LNG facility located within its distribution system in Gig Harbor, 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 natural gas purchase contracts, firm transportation capacity, firm storage capacity and other firm peaking resources. PSE believes it will be able to acquire incremental firm natural gas supply to meet anticipated growth in the requirements of its firm customers for the foreseeable future.

### NATURAL GAS SUPPLY FOR ELECTRIC CUSTOMERS

PSE purchases natural gas supplies for its power portfolio to meet demand for its combustion turbine generators. Supplies range from long-term to daily agreements as the demand for the turbines varies depending on market heat rates. Purchases are made 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 natural gas. PSE utilizes natural gas storage capacity to facilitate increased natural gas supply reliability and intra-day dispatch of PSE's gas-fired generation resources. During 2008, approximately 69.0% of natural gas for power purchased by PSE for power customers originated in British Columbia and 31.0% originated in the United States. Natural gas is either marketed outside PSE's service territory (off-system sales) or injected into the power portfolio's natural gas storage when the natural gas is not needed for the combustion turbines.

### NATURAL GAS STORAGE CAPACITY

PSE holds storage capacity in the Jackson Prairie and Clay Basin underground natural gas storage facilities adjacent to NWP's pipeline to serve PSE's natural gas customers. These facilities represent 46.1% 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 natural gas over a relatively short time period. Combined with capacity contracted from NWP's one-third stake in Jackson Prairie, PSE has peak firm withdrawal capacity of over 397,000 Dekatherms (one Dekatherm, or Dth, is equal to one million British thermal units or MMBtu) per day and total firm storage capacity of over 8,700,000 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 expanding the storage capacity at Jackson Prairie since March 2003, and plans to continue through 2012. At the end of this project, PSE will have added approximately 2,000,000 Dth of additional working storage capacity. In addition, in order to meet the growing peaking requirements in the region, PSE and the other two 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. The expansion was placed in-service November 1, 2008. PSE's share of this expansion is 104,000 Dth per day. The Clay Basin storage facility is a supply area storage facility that is used primarily to reduce portfolio costs through supply management efforts that take advantage of market price volatility, and is also used for system reliability. PSE holds over 13,400,000 Dth of Clay Basin storage capacity under two long-term contracts with remaining terms of four years and 11 years. Net of releases, PSE's maximum firm withdrawal capacity and total storage capacity at Clay Basin is over 95,000 Dth per day and exceeds 10,400,000 Dth, respectively.

Due to the recent expansion of Jackson Prairie storage capacity and deliverability, PSE's natural gas storage resources are expected to exceed customer requirements for the next two or three years. Therefore, effective December 1, 2008, 50,000 Dth of natural gas storage deliverability and 500,000 Dth of natural gas storage capacity have been temporarily assigned to support PSE's power portfolio, increasing natural gas supply reliability and facilitating intra-day dispatch of PSE's natural gas-fired generation resources.

### LNG AND PROPANE-AIR RESOURCES

LNG and propane-air resources provide firm natural 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 during the coldest hours or days. PSE contracts for LNG storage services of 241,700 Dth of PSE-owned gas at NWP's Plymouth facility, which is approximately three and one-half day's supply at a maximum daily deliverability of 70,500 Dth. At the Swarr vaporized-air station located in Renton, Washington, PSE owns storage capacity for approximately 1.5 million gallons of propane. This propane-air injection facility is capable of delivering the equivalent of 10,000 Dth of natural gas per day for up to 12 days directly into PSE's distribution system. PSE owns and operates an LNG peaking facility in Gig Harbor with total capacity of 10,600 Dth.

### NATURAL GAS TRANSPORTATION CAPACITY

PSE currently holds firm transportation capacity on pipelines owned by NWP, Gas Transmission Northwest (GTN), Nova Gas Transmission (NOVA), Foothills Pipe Lines (Foothills) and Westcoast Energy (Westcoast). GTN, NOVA, and Foothills are all TransCanada companies. Accordingly, PSE pays fixed monthly demand charges for the right, but not the obligation, to transport specified quantities of natural gas from receipt points to delivery points on such pipelines each day for the term or terms of the applicable agreements.

PSE holds firm year-round capacity on NWP through various contracts. PSE participates in the secondary pipeline capacity market to achieve savings for PSE's customers. PSE holds approximately 520,000 Dth per day of capacity for its natural gas customers on NWP that provides firm delivery to PSE's service territory. In addition, PSE holds approximately 524,000 Dth per day of seasonal firm capacity on NWP to provide for delivery of natural gas stored in Jackson Prairie and the Plymouth LNG facility during the heating season. PSE has firm transportation capacity on NWP through various contracts that supplies electric generating facilities with over 87,000 Dth per day. 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 less than one year to 36 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 15 years.

PSE's firm transportation capacity for its gas customers on Westcoast's pipeline is approximately 96,000 Dth under various contracts, with remaining terms of four to ten years. PSE has other firm transportation capacity on Westcoast's pipeline, which supplies the electric generating facilities, totaling approximately 22,000 Dth per day, with a remaining term of six years. During 2008, PSE committed to additional firm transportation capacity on Westcoast's pipeline for its electric generating facilities of approximately 25,000 Dth per day commencing on November 1, 2009 for a nine-year term. PSE has firm transportation capacity on NOVA and Foothills pipelines, totaling approximately 80,000 Dth per day, a portion of which has a remaining term of 15 years. PSE has annual renewal rights on the remainder of this capacity.

#### CAPACITY RELEASE

FERC regulates the release of firm pipeline and storage capacity for facilities which fall under its jurisdiction. Capacity releases allow shippers to temporarily or permanently relinquish unutilized capacity to recover all or a portion of the cost of such capacity. FERC allows capacity to be released through several methods including open bidding and pre-arrangement. PSE has acquired firm pipeline and storage service through capacity release provisions to serve its growing service territory and electric generation portfolio. PSE also mitigates a portion of the demand charges related to unutilized storage and pipeline capacity through capacity release. Capacity release benefits derived from the gas customer portfolio are passed on to PSE's natural gas 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 revenue impact of load reductions is accounted for in the ratemaking process of a general rate case.

Since 1995, PSE has been authorized by the Washington Commission to defer natural gas energy efficiency (or conservation) expenditures and recover them through a tariff tracker mechanism. The tracker mechanism allows PSE to defer efficiency expenditures and recover them in rates over the subsequent year. The tracker mechanism 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, natural gas energy efficiency expenditures have no impact on earnings.

Since May 1997, PSE has recovered electric energy efficiency (or conservation) expenditures through a tariff rider mechanism. The rider 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 mechanism, electric energy efficiency expenditures have no effect on earnings.

As part of PSE's 2006 general rate case, the Washington Commission authorized PSE to collect an incentive on electric conservation savings through the conservation rate rider if PSE exceeds annual baseline savings. These targets are reached through a collaborative process between PSE and the Conservation Resource Advisory Group (CRAG). PSE and CRAG meet regularly to share and discuss plans for energy efficiency programs, set targets and budgets and agree on a course of action.

### 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 now determine the impact, if any, that changes in such laws may have on its existing and future facilities and operations.

### Greenhouse Gas Policy

PSE recognizes the growing concern that increased atmospheric concentrations of GHG contribute to climate change. PSE believes that climate change is a very important issue that requires careful analysis and considered responses. PSE's policy is to encourage the use of cost-effective market mechanisms to mitigate and/or offset GHG emissions from its energy activities. PSE advocates for a mechanism that will ensure price certainty and facilitate planning in a way that will help maintain a dependable, cost-effective and diverse energy portfolio mix that will sustain our customers' needs now and into the future. However, PSE believes market mechanisms are not enough and governments must formulate active strategies to invent and demonstrate new large-scale, low-emissions technologies and energy systems. Market mechanisms can be useful in leveraging ways that will accelerate the adoption of new technologies through research, development and deployment, preferential treatment and appropriate price signaling, but they cannot be the only mechanisms. PSE also believes the United States cannot do this alone. All industrialized nations must find ways to engage emerging countries in carbon reduction. In the meantime, PSE continues to take appropriate steps to meet the goal of providing cost-effective and reliable energy while decreasing the impact on climate change. The full PSE Greenhouse Gas Policy is available at www.pse.com.

### Regulation Of Emissions

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

In June 2008, the Washington Department of Ecology adopted regulations implementing an Emissions Performance Standard of 1,100 lbs/MWh. All new generation facilities built in Washington and all long-term financial commitments entered into by Washington electric companies must comply with this standard. Facilities owned by PSE on or before July 1, 2008 are not subject to this standard. A PSE evaluation of facilities that were acquired after July 1, 2008, including Mint Farm, showed that it was compliant with the standard in its current operating configurations and no additional modifications are required. Future resource planning and resource acquisition decisions will take into account this regulation.

Climate policy continues to evolve at the state and federal levels. PSE remains involved in state, regional and federal policymaking activities that involve emissions and climate change. PSE anticipates that additional proposals will come from state and federal legislators in 2009 and beyond. In 2008, PSE made multiple submittals to the Western Climate Initiative (WCI) to provide its recommendations on the WCI design proposals, and it has participated in stakeholder committee groups and will continue this effort.

### Emissions Inventory

During 2008, PSE's total electric retail load of 22.0 million MWh was served from a supply portfolio of owned and purchased resources. Since 2002, PSE has voluntarily undertaken an inventory of its GHG emissions associated with this portfolio. Such inventory follows the protocol established by the World Resource Institute GHG Protocol. The most recent data indicate that PSE's total GHG emissions (direct and indirect) from its electric supply portfolio in 2007 were 13.1 million tons carbon dioxide equivalent. Approximately 48.3% of these emissions (approximately 6.3 million tons) are associated with PSE's ownership and contractual interests in Colstrip.

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 its 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.

### Colstrip Emission Controls

The federal Clean Air Mercury Rule, enacted by the Environmental Protection Agency (EPA) in May 2005, was vacated by the D.C. Circuit Court in February, 2008 and the final resolution of this matter is still pending. However, the Montana Board of Environmental Review approved a Montana mercury control rule to limit mercury emissions from coal-fired plants on October 16, 2006 (with limits of 0.9 lbs/TBtu for plants burning coal like that used at Colstrip) which remains in effect. In 2008, the Colstrip owners, based on testing performed in 2006, 2007 and 2008, ordered mercury control equipment intended to achieve the new limit. Installation of this equipment is planned for 2009, after which an evaluation will be conducted of whether additional controls, if any, are necessary.

In February 2007, Colstrip was notified by EPA that Colstrip Units 1 & 2 were determined to be subject to EPA's Best Available Retrofit Technology (BART) requirements. PSE submitted a BART engineering analysis for Colstrip Units 1 & 2 in August 2007 and responded to an EPA request for additional analyses with an addendum in June 2008. PSE cannot yet determine the need for or costs of additional controls to comply with this rule.

**FEDERAL ENDANGERED SPECIES ACT**

Since 1991, a total of 17 species of Northwest and Columbia River Basin 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 Endangered Species Act impacts may affect PSE operations, potentially representing cost exposure and operational constraints. PSE is actively engaged with 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 March 2, 2009 are listed below along with their experience during the past five years. Officers of Puget Energy are elected for one-year terms.

| NAME | AGE | OFFICES |
|---|---|---|
| S. P. Reynolds | 61 | President and Chief Executive Officer since February 2009; Chairman, President and Chief Executive Officer 2005 – 2009; President and Chief Executive Officer, 2002 – 2005. Director since January 2002. |
| J. W. Eldredge | 58 | Vice President, Controller and Chief Accounting Officer since May 2007; Vice President, Corporate Secretary and Chief Accounting Officer 2005 – 2007; Corporate Secretary and Chief Accounting Officer 1999 – 2005. |
| D. E. Gaines | 52 | Vice President Finance and Treasurer since March 2002. |
| E. M. Markell | 57 | Executive Vice President and Chief Financial Officer since May 2007; Senior Vice President Energy Resources 2003 – 2007. |
| J. L. O'Connor | 52 | Senior Vice President, General Counsel, Corporate Secretary and Chief Ethics and Compliance Officer since May 2007; Senior Vice President, General Counsel, Chief Ethics and Compliance Officer 2005 - 2007; Vice President and General Counsel, 2003 - 2005. |

The executive officers of PSE as of March 2, 2009 are listed below along with their business experience during the past five years. Officers of PSE are elected for one-year terms.

| NAME | AGE | OFFICES |
|---|---|---|
| S. P. Reynolds | 61 | President and Chief Executive Officer since February 2009; Chairman, President and Chief Executive Officer 2005 – 2009; Director since January 2002; President and Chief Executive Officer 2002 – 2005. |
| J. W. Eldredge | 58 | Vice President, Controller and Chief Accounting Officer since May 2007; Vice President, Corporate Secretary, Controller and Chief Accounting Officer 2001 – 2007. |
| D. E. Gaines | 52 | Vice President Finance and Treasurer since March 2002. |
| K. J. Harris | 44 | Executive Vice President and Chief Resource Officer since May 2007; Senior Vice President Regulatory Policy and Energy Efficiency 2005 – 2007; Vice President Regulatory and Government Affairs, 2003 – 2005; Vice President Regulatory Affairs, 2002 – 2003. |
| E. M. Markell | 57 | Executive Vice President and Chief Financial Officer since May 2007; Senior Vice President Energy Resources 2003 – 2007. |
| J. L. O'Connor | 52 | Senior Vice President, General Counsel, Corporate Secretary and Chief Ethics and Compliance Officer since May 2007; Senior Vice President, General Counsel, Chief Ethics and Compliance Officer 2005 – 2007; Vice President and General Counsel, 2003 – 2005. |
| B. A. Valdman | 46 | Executive Vice President and Chief Operating Officer since May 2007; Senior Vice President Finance and Chief Financial Officer 2003 – 2007. |

# 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 wholesale and retail customers are determined by both the Washington Commission and FERC.

PSE is also subject to the regulatory authority of the Washington Commission with respect to accounting, operations, the issuance of securities and certain other matters, and the regulatory authority of FERC with respect to the transmission of electric energy, the sale 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.

The Washington Commission determines the rates PSE may charge to its electric retail customers based in part on historic test year costs plus weather normalized assumptions about rate year hydro conditions and power costs. Non-energy costs for natural gas retail customers are based on historic test year costs. If in a specific year PSE's costs are higher than what is allowed to be recovered in rates, revenues may not be sufficient to permit PSE to earn its allowed return or to cover its costs. In addition, the Washington Commission decides what level of expense and investment is reasonable and prudent in providing electric and natural gas 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 PSE AND ITS CUSTOMERS PURSUANT TO A GRADUATED SCALE, COULD RESULT IN SIGNIFICANT INCREASES IN PSE'S EXPENSES IF POWER COSTS ARE SIGNIFICANTLY HIGHER THAN THE BASELINE RATE.

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. As a result, if power costs are significantly higher than the baseline rate, PSE's expenses could significantly increase.

### 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.

**PSE'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, its cash flow and earnings would be negatively affected. Factors which could cause purchased power and natural 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 or precipitation;
- 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, natural 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 takes into account the expected probability of default by counterparties, the actual exposure to a default by a particular counterparty could be greater than predicted.

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 implementing the federal licensing requirements for the Snoqualmie Falls hydroelectric project and the Baker River hydroelectric project. The implementation of federal licensing requirements is an ongoing political and public regulatory process that involves sensitive resource issues. PSE cannot predict with certainty the conditions that may be imposed during the implementation process, or the economic impact of those requirements, or whether PSE will be able to meet all of these requirements or will need to seek modifications or amendments of the license.

**COSTS OF COMPLIANCE WITH ENVIRONMENTAL, CLIMATE CHANGE AND ENDANGERED SPECIES LAWS ARE SIGNIFICANT AND THE COST OF COMPLIANCE WITH NEW AND EMERGING LAWS AND REGULATIONS AND THE INCURRENCE OF ASSOCIATED LIABILITIES COULD ADVERSELY AFFECT PSE'S RESULTS OF OPERATIONS.**

PSE's operations are subject to extensive federal, state and local laws and regulations relating to environmental, climate change and endangered species protection. To comply with these legal requirements, PSE must spend significant sums on measures including resource planning, remediation, monitoring, pollution control equipment and emissions related abatement and fees. New environmental, climate change 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, climate change and endangered species expenditures made by PSE 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 such 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. 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.

Specific to climate change, Washington State has adopted both a renewable portfolio standard and greenhouse gas legislation, including an emission performance standard provision. Recent U.S. Supreme Court decisions related to climate change have also drawn greater attention to this issue at the federal, state and local level. PSE cannot yet determine the costs of compliance with the recently enacted legislation.

**PSE'S BUSINESS IS DEPENDENT ON ITS ABILITY TO SUCCESSFULLY ACCESS CAPITAL.**

PSE relies on access to bank borrowings and short-term money markets as sources of liquidity and longer-term debt markets to fund its utility construction program and other capital expenditure requirements not satisfied by cash flow from its operations or equity investment from its parent, Puget Energy. If PSE is unable to access capital on reasonable terms, 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. Capital and credit market disruptions or a downgrade of PSE's credit rating may increase PSE'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 & Poor's and Moody's Investor Services rate PSE's senior secured debt at "A-" 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

Puget Energy's and PSE's facilities, the borrowing spreads over LIBOR and commitment fees increase if their respective corporate credit ratings decline. A downgrade in commercial paper ratings could increase the cost of commercial paper and limit or preclude PSE's ability to issue commercial paper under its current programs.

Any downgrade below investment grade of PSE's senior secured debt could cause counterparties in the wholesale electric, wholesale natural 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 revenues, expenses and operating results. 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 as well as conservation efforts 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 the Company'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 natural 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 in examination, upon appeal or through litigation. The Company's tax obligations include income, real estate, public utility, municipal, 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 may be subject to challenge by the taxing authorities.

**POOR PERFORMANCE OF PENSION AND POSTRETIREMENT BENEFIT PLAN INVESTMENTS AND OTHER FACTORS IMPACTING PLAN COSTS COULD UNFAVORABLY IMPACT THE COMPANY'S CASH FLOWS AND LIQUIDITY.**

PSE provides a defined benefit pension plan to PSE employees and postretirement benefits to certain PSE employees and former employees. Costs of providing these benefits are based in part on the value of the plan's assets and therefore, continued adverse market performance could result in lower rates of return for the investments that fund the Company's pension and postretirement benefits plans and could increase the Company's funding requirements related to the pension plans. Any contributions to PSE's plans in 2009 and beyond and the timing of the recovery of such contributions in general rate cases could impact the Company's cash flow and liquidity.

**THE COMPANY DEPENDS ON AN AGING WORK FORCE AND THIRD PARTY VENDORS TO PERFORM CERTAIN IMPORTANT SERVICES.**

The Company continues to be concerned about the availability and aging of skilled workers for special complex utility functions. The Company also hires third parties to perform a variety of normal business functions, such as data warehousing and management, electric transmission, electric and gas distribution construction and maintenance, and certain billing and metering processes. The unavailability of skilled workers or unavailability of such vendors could adversely affect the quality and cost of the Company's gas and electric service, and accordingly, the Company's results of operations.

### RISKS RELATING TO PUGET ENERGY'S CORPORATE STRUCTURE

**AS A HOLDING COMPANY, PUGET ENERGY DEPENDS ON PSE'S ABILITY TO PAY DIVIDENDS.**

As a holding company with no significant operations of its own, the primary source of funds for the repayment of debt and other expenses, as well as payment of dividends to its shareholder, is cash 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 or repay debt or other expenses, 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 meet its obligations or pay dividends.

The payment of dividends by PSE to Puget Energy is restricted by provisions of certain covenants applicable to long-term debt contained in the Mortgage Indentures. In addition, beginning February 6, 2009, as approved in the Washington Commission merger order, PSE dividends may not be declared or paid if its common equity ratio is 44.0% or below except to the extent a lower equity ratio is ordered by the Washington Commission. In addition, pursuant to the merger order, PSE cannot declare or make any distribution on the date of distribution if either: (a) the ratio of PSE's Earnings Before Interest, Tax, Depreciation and Amortization (EBITDA) to PSE interest for the most recently ended four fiscal quarter periods prior to such date is equal or greater than three to one; or (b) PSE's corporate credit/issuer rating is at least BBB- with Standard & Poor's and Baa3 with Moody's. Puget Energy's ability to pay dividends to its shareholder is also limited by the merger order, beginning February 6, 2009. Pursuant to the merger order, Puget Energy may not declare or make a distribution unless on such date Puget Energy's ration of consolidated EBITDA to consolidated interest expense for the most recently ended four fiscal quarter periods prior to such date is equal or greater than two to one.

## ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

# ITEM 2. PROPERTIES

The principal electric generating plants and underground natural 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 and Proceeding Relating to the merger.

# 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

Upon the completion of the merger on February 6, 2009, each share of Puget Energy common stock, its only class of common equity, was cancelled and converted into the right to receive $30.00, without interest. Consequently, Puget Energy's common stock was delisted from trading on the New York Stock Exchange (NYSE). As a result of the merger, all of the outstanding shares of Puget Energy's common stock, the only class of common equity of Puget Energy, are held by its direct parent Puget Equico, which is an indirect wholly owned subsidiary of Puget Holdings. The outstanding shares of PSE's common stock, the only class of common equity of PSE, are held by Puget Energy and are not publicly traded.

In the two most recent fiscal years, Puget Energy has declared quarterly dividends in the amount of $0.25 per share on each share of common stock outstanding. On January 22, 2009, Puget Energy also declared a special pro rata dividend of $0.04448 per share. The payment of dividends on Puget Energy common stock is restricted by provisions of certain covenants applicable to long-term debt contained in the Mortgage Indentures. In addition, beginning February 6, 2009, as approved in the Washington Commission merger order, Puget Energy may not declare or make a distribution unless on such date Puget Energy's ratio of consolidated EBITDA to consolidated interest expense for the most recently ended four fiscal quarter periods prior to such date is equal or greater than two to one. Also beginning on February 6, 2009, as approved in the Washington Commission merger order, PSE dividends may not be declared or paid if its common equity ratio is 44.0% or below except to the extent a lower equity ratio is ordered by the Washington Commission. In addition, PSE cannot declare or make any distribution on the date of distribution if either: (a) the ratio of PSE's EBITDA to PSE interest for the most recently ended four fiscal quarter periods prior to such date is equal or greater than three to one; or (b) PSE's corporate credit/issuer rating is at least BBB- with Standard & Poor's and Baa3 with Moody's.

# 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 | 2008 | 2007 | 2006 | 2005 | 2004 |
|---|---|---|---|---|---|
| Operating revenue | $ 3,357,773 | $ 3,220,147 | $ 2,907,063 | $ 2,578,008 | $ 2,202,333 |
| Operating income | 382,748 | 441,034 | 420,851 | 390,297 | 362,766 |
| Income from continuing operations | 154,929 | 184,676 | 167,224 | 146,283 | 125,410 |
| Net income | 154,929 | 184,464 | 219,216 | 155,726 | 55,022 |
| Basic earnings per common share from continuing operations | 1.20 | 1.57 | 1.44 | 1.43 | 1.26 |
| Basic earnings per common share | 1.20 | 1.57 | 1.89 | 1.52 | 0.55 |
| Diluted earnings per common share from continuing operations | 1.19 | 1.56 | 1.44 | 1.42 | 1.26 |
| Diluted earnings per common share | 1.19 | 1.56 | 1.88 | 1.51 | 0.55 |
| Dividends per common share | $ 1.00 | $ 1.00 | $ 1.00 | $ 1.00 | $ 1.00 |
| Book value per common share | 17.53 | 19.45 | 18.15 | 17.52 | 16.24 |
| Total assets at year end | $ 8,368,406 | $ 7,598,736 | $ 7,066,039 | $ 6,609,951 | $ 5,851,219 |
| Long-term debt | 2,270,860 | 2,428,860 | 2,608,360 | 2,183,360 | 2,069,360 |
| Preferred stock subject to mandatory redemption | 1,889 | 1,889 | 1,889 | 1,889 | 1,889 |
| Junior subordinated notes | 250,000 | 250,000 | -- | -- | -- |
| Junior subordinated debentures of the corporation payable to a subsidiary trust holding mandatorily redeemable preferred securities | -- | -- | 37,750 | 237,750 | 280,250 |

PUGET SOUND ENERGY
SUMMARY OF OPERATIONS
(DOLLARS IN THOUSANDS)

| YEARS ENDED DECEMBER 31 | 2008 | 2007 | 2006 | 2005 | 2004 |
|---|---|---|---|---|---|
| Operating revenue | $ 3,357,773 | $ 3,220,147 | $ 2,907,063 | $ 2,578,008 | $ 2,202,333 |
| Operating income | 392,386 | 450,384 | 422,682 | 391,650 | 363,748 |
| Net income for common stock | 162,736 | 191,127 | 176,740 | 146,769 | 126,192 |
| Total assets at year end | $ 8,370,159 | $ 7,592,210 | $ 7,061,413 | $ 6,339,800 | $ 5,564,087 |
| Long-term debt | 2,270,860 | 2,428,860 | 2,608,360 | 2,183,360 | 2,064,360 |
| Preferred stock subject to mandatory redemption | 1,889 | 1,889 | 1,889 | 1,889 | 1,889 |
| Junior subordinated notes | 250,000 | 250,000 | -- | -- | -- |
| Junior subordinated debentures of the corporation payable to a subsidiary trust holding mandatorily redeemable preferred securities | -- | -- | 37,750 | 237,750 | 280,250 |

# 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 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 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" and "Risk Factors" 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, Inc. (PSE), a regulated electric and natural gas utility company. Until May 7, 2006, Puget Energy owned a 90.9% interest in InfrastruX Group, Inc. (InfrastruX), a utility construction and services company that was sold to an affiliate of Tenaska Power Fund, L.P. (Tenaska).

PSE is the largest electric and natural gas utility in the state of Washington, primarily engaged in the business of electric transmission, distribution, generation and natural gas distribution. Puget Energy's business strategy is to generate stable earnings and cash flow by offering reliable electric and natural gas service in a cost effective manner through PSE. An overview of significant recent developments affecting Puget Energy is provided below.

On February 6, 2009, Puget Holdings LLC (Puget Holdings) completed its merger with Puget Energy. Puget Holdings is a consortium of long-term infrastructure investors led by Macquarie Infrastructure Partners I, Macquarie Capital Group Limited, the Canada Pension Plan Investment Board and British Columbia Investment Management Corporation, and also includes Alberta Investment Management Corporation, Macquarie-FSS Infrastructure Trust and Macquarie Infrastructure Partners II (collectively, the Consortium). At the time of the merger, each issued and outstanding share of common stock of Puget Energy, other than any shares in respect of which dissenter's rights are perfected and other than any shares owned by the Consortium, were cancelled and converted automatically into the right to receive $30.00 in cash, without interest. As a result of the merger, Puget Energy is a direct wholly owned subsidiary of Puget Equico LLC (Puget Equico), which is an indirect wholly owned subsidiary of Puget Holdings.

**Puget Sound Energy.** PSE generates revenues primarily from the sale of electric and natural gas services to retail residential and commercial customers within Washington State. PSE's operating revenues and associated expenses are not generated evenly throughout 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 temperatures. PSE normally experiences its highest retail energy sales and 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 electric prices in the wholesale markets in which PSE purchases electricity and the amount of low-cost hydroelectric energy supplies available to PSE also make quarter-to-quarter comparisons difficult.

PSE faces uncertainties in the future regarding both electric and natural gas customer growth and sales growth. The number of electric customers is expected to continue to grow at a rate of growth based on a forecasted slowing of regional population growth. Aside from the impact of fluctuations in temperature, residential electric use per customer is expected to continue a long-term trend of slow decline based on continued energy efficiency improvements combined with the impact of higher retail rates. Electric residential usage per customer in 2008 was higher than 2007 due to colder temperatures.

The number of natural gas customers is expected to grow at rates slightly above electric customers due to the continued trend of the conversion of existing electric customers to natural gas. Aside from weather impacts, residential natural gas use per customer is also expected to continue a long-term trend of decline based on continued energy efficiency improvements. Natural gas residential usage per customer in 2008 was higher than 2007 due to colder temperatures.

As a regulated utility company, PSE is subject to the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC) standards and Washington Utilities and Transportation Commission (Washington Commission) regulation which affects a wide array of business activities, including regulating 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 attainment of PSE's business objectives. 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 natural gas and electric distribution and transmission lines; increasing regulatory standards for system reliability and wholesale market stability over time and significant evolving environmental legislation.

On October 8, 2008, the Washington Commission issued its order in PSE's consolidated electric and natural gas general rate case filed in December 2007, approving a general rate increase for electric customers of $130.2 million or 7.1% annually, and an increase in natural gas rates of $49.2 million or 4.6% annually. The rate increases for electric and natural gas customers were effective November 1, 2008. In its order, the Washington Commission approved a weighted cost of capital of 8.25%, or 7.00% after-tax and a capital structure that included 46.0% common equity with a return on equity of 10.15%.

PSE's main business objective is to provide reliable, safe and cost-effective energy to its customers. To help accomplish this objective, PSE seeks to become more energy efficient and environmentally responsible in its energy supply portfolio. PSE filed its most recent Integrated Resource Plan (IRP) on May 31, 2007 with the Washington Commission. The 2007 IRP demonstrated PSE's need to acquire significant amounts of new generating resources, driven primarily by expiration of existing purchase power contracts. The plan supports a strategy of significantly increasing energy efficiency programs, pursuing additional renewable resources (primarily wind) and additional base load natural gas-fired generation to meet the growing needs of its customers. The next IRP will be filed in May 2009. On July 28, 2008, PSE completed the purchase of the 125 megawatts (MW) Sumas cogeneration power plant. On December 5, 2008, PSE purchased a 50.0% undivided interest in four proposed development-stage wind projects totaling 1,300 MW in Columbia and Garfield counties in Washington State from RES America, Inc. On December 5, 2008, PSE completed the purchase of the 310 MW Mint Farm natural gas-fired power plant (Mint Farm), which is located in Longview, Washington, for approximately $240.0 million. In addition, PSE began expansion of the Company's existing 229 MW Wild Horse wind project (Wild Horse) to include an additional 44 MW of wind generating capacity. The expansion is expected to be completed by December 2009. These acquisitions are part of PSE's long-range plan to meet its customers' steadily growing electricity needs and changes to its supply portfolio.

**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 readers' 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 and until May 7, 2006, InfrastruX. Net income in 2008 was $154.9 million on operating revenues from continuing operations of $3.4 billion as compared to $184.5

million on operating revenues from continuing operations of $3.2 billion in 2007 and $219.2 million on operating revenues from continuing operations of $2.9 billion in 2006. Income from continuing operations in 2008 was $154.9 million as compared to $184.7 million in 2007 and $167.2 million in 2006. Net income for 2007 and 2006 includes the results of discontinued operations for InfrastruX.

Basic earnings per share in 2008 was $1.20 on 129.4 million weighted-average common shares outstanding as compared to $1.57 on 117.7 million weighted-average common shares outstanding in 2007 and $1.89 on 116.0 million weighted-average common shares outstanding in 2006. Diluted earnings per share in 2008 was $1.19 on 130.1 million weighted-average common shares outstanding as compared to $1.56 on 118.3 million weighted-average common shares outstanding in 2007 and $1.88 on 116.5 million weighted-average common shares outstanding in 2006. Included in basic and diluted earnings per share for 2006 is discontinued operations of $0.45 and $0.44, respectively.

Net income for 2008 was positively impacted by higher electric and gas margins compared to the same period in 2007. Net income was negatively impacted by an increase in utility operations and maintenance and an increase in depreciation and amortization. The increase in expenses was partially offset by an increase in other income and a decrease in interest expense due to lower average debt outstanding as a result of the equity issuance in December 2007 and lower average interest rates on outstanding debt. For the year ended December 31, 2008, Puget Energy's expenses related to the merger increased $1.2 million pre-tax.

Net income for 2007 was positively impacted by higher energy margins driven by increased sales volumes and favorable hydroelectric conditions. Net income was negatively impacted by higher operation and maintenance expenses, taxes other than income taxes net of revenue sensitive taxes and an increase in depreciation and interest expenses, including costs related to the addition of new generating resources and energy delivery infrastructure investments. During the fourth quarter 2007, Puget Energy incurred $8.1 million in costs related to the merger.

## 2008 COMPARED TO 2007

### PUGET SOUND ENERGY

**Energy Margins.** The following table displays the details of electric margin changes from 2007 to 2008. 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)<br>TWELVE MONTHS ENDED DECEMBER 31 | ELECTRIC MARGIN<br>2008 | <br>2007 | <br>CHANGE | <br>PERCENT CHANGE |
|---|---|---|---|---|
| Electric operating revenue[1] | $ 2,129.5 | $ 1,997.8 | $ 131.7 | 6.6 % |
| Less: Other electric operating revenue | (55.4) | (41.9) | (13.5) | (32.2) |
| Add: Other electric operating revenue – gas supply resale | 15.8 | 1.5 | 14.3 | * |
| Total electric revenue for margin | 2,089.9 | 1,957.4 | 132.5 | 6.8 |
| Adjustments for amounts included in revenue: | | | | |
| Pass-through tariff items | (63.9) | (43.0) | (20.9) | (48.6) |
| Pass-through revenue-sensitive taxes | (146.3) | (133.6) | (12.7) | (9.5) |
| Net electric revenue for margin | 1,879.7 | 1,780.8 | 98.9 | 5.6 |
| Minus power costs: | | | | |
| Purchased electricity[1] | (903.3) | (895.6) | (7.7) | (0.9) |
| Electric generation fuel[1] | (212.3) | (143.4) | (68.9) | (48.0) |
| Residential exchange[1] | 40.7 | 52.4 | (11.7) | (22.3) |
| Total electric power costs | (1,074.9) | (986.6) | (88.3) | (8.9) |
| Electric margin[2] | $ 804.8 | $ 794.2 | $ 10.6 | 1.3 % |

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.*

* *Percent change not applicable or meaningful*

Electric margin increased $10.6 million in 2008 as compared to 2007. The increase was primarily due to recovery of ownership and operating costs of Goldendale electric generating facility (Goldendale) included in the power cost only rate case (PCORC) rate increase of 3.7% effective September 1, 2007 and in the general rate increase of 7.1% effective November 1, 2008 which increased electric margin by $18.9 million. The increase in electric margin benefited from an increase in retail sales volumes of 1.8% which increased electric margin by $13.8 million. The increase in electric margin was partially offset by higher power supply costs of approximately $24.5 million driven by a reduction in hydroelectric generation and an increase in natural gas fuel prices.

The following table displays the details of gas margin changes from 2007 to 2008. Gas margin is natural gas sales to retail and transportation customers less pass-through tariff items and revenue-sensitive taxes, and the cost of natural gas purchased, including natural gas transportation costs to bring natural gas to PSE's service territory.

| (DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31 | GAS MARGIN 2008 | 2007 | CHANGE | PERCENT CHANGE |
|---|---|---|---|---|
| Gas operating revenue[1] | $ 1,216.9 | $ 1,208.0 | $ 8.9 | 0.7% |
| Less: Other gas operating revenue | (17.7) | (17.4) | (0.3) | (1.7) |
| Total gas revenue for margin | 1,199.2 | 1,190.6 | 8.6 | 0.7 |
| Adjustments for amounts included in revenue: | | | | |
| Pass-through tariff items | (11.6) | (9.6) | (2.0) | (20.8) |
| Pass-through revenue-sensitive taxes | (94.4) | (95.2) | 0.8 | 0.8 |
| Net gas revenue for margin | 1,093.2 | 1,085.8 | 7.4 | 0.7 |
| Minus purchased gas costs[1] | (737.9) | (762.1) | 24.2 | 3.2 |
| Gas margin[2] | $ 355.3 | $ 323.7 | $ 31.6 | 9.8% |

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 $31.6 million in 2008 as compared to 2007. This increase is primarily due to an increase in gas margin of $15.5 million related to a 4.8% increase in gas therm volume sales and a 2.8% general rate increase effective January 13, 2007 and a 4.6% general rate increase effective November 1, 2008 which contributed $19.7 million. Partially offsetting the margin increase was a change in customer mix and other pricing variances, which resulted in a decrease of $3.5 million.

**Electric Operating Revenues.** The table below sets forth changes in electric operating revenues for PSE from 2007 to 2008.

| (DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31 | 2008 | 2007 | CHANGE | PERCENT CHANGE |
|---|---|---|---|---|
| Electric operating revenues: | | | | |
| Residential sales | $ 1,046.9 | $ 951.1 | $ 95.8 | 10.1% |
| Commercial sales | 800.9 | 748.8 | 52.1 | 7.0 |
| Industrial sales | 106.1 | 105.2 | 0.9 | 0.9 |
| Other retail sales, including unbilled revenue | 27.5 | 31.7 | (4.2) | (13.2) |
| Total retail sales | 1,981.4 | 1,836.8 | 144.6 | 7.9 |
| Transportation sales | 7.9 | 9.4 | (1.5) | (16.0) |
| Sales to other utilities and marketers | 84.7 | 109.7 | (25.0) | (22.8) |
| Other | 55.5 | 41.9 | 13.6 | 32.5 |
| Total electric operating revenues | $ 2,129.5 | $ 1,997.8 | $ 131.7 | 6.6% |

Electric retail sales increased $144.6 million for 2008 as compared to 2007 due primarily to colder average temperatures in the Pacific Northwest during the first half of 2008 and during the month of December 2008 which saw record energy peak loads and an increase in customer growth. Retail electricity usage increased 388,249 megawatt hours (MWh) or 1.8% for 2008 as compared to the same period in 2007, which resulted in an increase of approximately $34.9 million in electric operating revenue. The increase in electricity usage was related in part to 1.5% higher average number of customers served in 2008 as compared to 2007. The electric general rate decrease of January 13, 2007, the PCORC rate increase of September 1, 2007 coupled with the electric general rate increase of November 1, 2008 increased electric retail sales by $104.6 million for 2008 as compared to 2007. The benefits of the Residential and Farm Energy Exchange Benefit credited to customers reduced electric operating revenues by $42.5 million in 2008 compared to $54.9 million for the same period in 2007. This credit also reduced power costs by a corresponding amount with no impact on earnings.

Sales to other utilities and marketers decreased $25.0 million for 2008 as compared to 2007 due to a decrease in sales volume of 588,157 MWh or 26.1%, which resulted in a decrease of $28.6 million. This decrease was partially offset by an increase in PSE's average wholesale sales price to other utilities and marketers as compared to 2007 which resulted in an increase of approximately $3.6 million.

Other electric revenues increased $13.6 million for 2008 as compared to 2007 primarily due to an increase of $14.3 million in noncore gas sales.

The following electric rate changes were approved by the Washington Commission in 2008 and 2007:

| Type of Rate Adjustment | Effective Date | Average Percentage Increase (Decrease) in Rates | Annual Increase (Decrease) in Revenues (Dollars in Millions) |
|---|---|---|---|
| Electric General Rate Case | January 13, 2007 | (1.3)% | $ (22.8) |
| Power Cost Only Rate Case | September 1, 2007 | 3.7 % | 64.7 |
| Electric General Rate Case | November 1, 2008 | 7.1 % | 130.2 |

**Gas Operating Revenues.** The table below sets forth changes in gas operating revenues for PSE from 2007 to 2008.

| (Dollars in Millions) Twelve Months Ended December 31 | 2008 | 2007 | Change | Percent Change |
|---|---|---|---|---|
| Gas operating revenues: | | | | |
| Residential sales | $ 766.8 | $ 756.2 | $ 10.6 | 1.4% |
| Commercial sales | 373.7 | 363.0 | 10.7 | 2.9 |
| Industrial sales | 44.0 | 57.7 | (13.7) | (23.7) |
| Total retail sales | 1,184.5 | 1,176.9 | 7.6 | 0.6 |
| Transportation sales | 14.7 | 13.7 | 1.0 | 7.3 |
| Other | 17.7 | 17.4 | 0.3 | 1.7 |
| Total gas operating revenues | $ 1,216.9 | $ 1,208.0 | $ 8.9 | 0.7% |

Gas retail sales increased $7.6 million for 2008 as compared to the same period in 2007 due to an increase in gas therm sales of 53.8 million, or 4.8%, reflecting customer growth and colder average temperatures in the Pacific Northwest during the first half 2008 and during December 2008, which contributed $61.2 million. The increase was primarily offset by lower Purchased Gas Adjustment (PGA) mechanism rates that were effective October 1, 2007. PSE's gas margin and net income are not affected by changes under the PGA mechanism. The effects of the PGA mechanism rate decrease of 13.0% were offset by a 2.8% natural gas general rate increase effective January 13, 2007, a 11.1% PGA rate increase effective October 1, 2008 and a 4.6% natural gas general rate increase effective November 1, 2008 resulting in a decrease of $53.5 million in natural gas operating revenues. The PGA mechanism passes through to customers increases or decreases in the natural 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 natural gas pipeline transportation costs.

Gas transportation sales increased $1.0 million for 2008 as compared to the same period in 2007 due primarily to an increase in natural gas general rates effective January 13, 2007 and November 1, 2008 which contributed $0.8 million and an increase in gas transportation volume of 4.2 million or 2.0% which contributed $0.2 million.

The following natural gas rate changes were approved by the Washington Commission in 2008 and 2007:

| Type of Rate Adjustment | Effective Date | Average Percentage Increase (Decrease) in Rates | Annual Increase (Decrease) in Revenues (Dollars in Millions) |
|---|---|---|---|
| Gas General Rate Case | January 13, 2007 | 2.8 % | $ 29.5 |
| Purchased Gas Adjustment | October 1, 2007 | (13.0)% | (148.1) |
| Purchased Gas Adjustment | October 1, 2008 | 11.1 % | 108.8 |
| Gas General Rate Case | November 1, 2008 | 4.6 % | 49.2 |

**NON-UTILITY OPERATING REVENUES**

The table below sets forth changes in non-utility operating revenues for PSE from 2007 to 2008.

| (DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31, | 2008 | 2007 | CHANGE | PERCENT CHANGE |
|---|---|---|---|---|
| Non-utility operating revenue | $ 11.4 | $ 14.3 | $ (2.9) | (20.3) % |

Non-utility operating revenues decreased $2.9 million in 2008 as compared to the same period in 2007 due to a decrease in property sales in 2008 as compared to 2007.

**Operating Expenses.** The table below sets forth significant changes in operating expenses for PSE from 2007 to 2008.

| (DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31 | 2008 | 2007 | CHANGE | PERCENT CHANGE |
|---|---|---|---|---|
| Purchased electricity | $ 903.3 | $ 895.6 | $ 7.7 | 0.9 % |
| Electric generation fuel | 212.3 | 143.4 | 68.9 | 48.0 |
| Residential exchange | (40.7) | (52.4) | 11.7 | 22.3 |
| Purchased gas | 737.9 | 762.1 | (24.2) | (3.2) |
| Unrealized (gain)/loss on derivative instruments | 7.5 | (2.7) | 10.2 | * |
| Utility operations and maintenance | 461.6 | 403.7 | 57.9 | 14.3 |
| Depreciation and amortization | 312.1 | 279.2 | 32.9 | 11.8 |
| Conservation amortization | 61.7 | 40.0 | 21.7 | 54.3 |
| Taxes other than income taxes | 297.2 | 288.5 | 8.7 | 3.0 |

* *Percent change not applicable or meaningful*

**Purchased electricity** expenses increased $7.7 million in 2008 as compared to 2007 primarily as a result of higher wholesale market prices during the first half of 2008 which contributed $57.4 million offset by a decrease in purchased power of 1,009.9 MWh or 6.0%, resulting in a decrease of $48.9 million. The decrease in purchased power is related to increased production from company-owned combustion turbines, wind facilities and thermal generating facilities. Also offsetting the increase were decreased transmission costs and other expenses, which contributed $0.9 million.

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 $68.9 million in 2008 as compared to 2007 primarily due to an increase in generation from company-owned combustion turbine plants which contributed $66.6 million to the cost of fuel and an increase of $2.3 million due to higher volumes of electricity generated at the Colstrip, Montana coal-fired steam electric generation facility (Colstrip) which increased coal costs in 2008 as compared to 2007. The increase in combustion turbine generation was due to lower hydroelectric generation and higher wholesale market price of electricity.

**Residential exchange credits** associated with the Bonneville Power Administration (BPA) Residential Exchange Program (REP) decreased $11.7 million in 2008 as compared to the same period in 2007 as a result of the suspension of the residential and small farm customer electric credit in rates effective June 7, 2007. The suspension was due to an adverse ruling from the U.S. Court of Appeals for the Ninth Circuit (Ninth Circuit) which states that BPA actions in entering into residential exchange settlement agreements with investor owned utilities were not in accordance with the law. In April 2008, PSE signed an agreement pursuant to which BPA would pay PSE $53.7 million for fiscal year 2008 REP benefits. Of this amount PSE received approval to pass-through to customers approximately $20.0 million over a one-month period. The remaining $33.7 million was used to offset PSE's regulatory asset. The REP 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. Based upon a new REP agreement, PSE resumed passing through REP credits to customers on November 1, 2008.

**Purchased gas** expenses decreased $24.2 million in 2008 as compared to 2007 primarily due to a decrease in PGA rates as approved by the Washington Commission effective October 1, 2007 and partially offset by higher customer therm sales. The PGA mechanism allows PSE to recover expected natural gas costs, and defer, as a receivable or liability, any natural gas costs that exceed or fall short of this expected natural gas cost amount in PGA mechanism rates, including accrued interest. The PGA mechanism payable balance at December 31, 2008 was $8.9 million as compared to a payable balance at December 31, 2007 of $77.9 million. PSE is authorized by the Washington Commission to accrue carrying costs on PGA receivable and payable balances. A receivable balance in the PGA mechanism reflects an underrecovery of market natural gas cost through rates. A payable balance reflects overrecovery of market natural gas cost through rates.

**Unrealized loss on derivative instruments** increased $10.2 million in 2008 as compared to 2007 primarily as a result of decreasing market prices in both electric and gas sectors in the third and fourth quarters 2008 which had a negative impact on derivative market prices, including Mid-Columbia and gas derivative contracts. In addition, $6.1 million of this unrealized loss is associated with the ineffective portion of cash flow hedges for certain power purchase agreements.

**Utility operations and maintenance** expense increased $57.9 million in 2008 as compared to the same period in 2007. The increase for 2008 was primarily due to a $23.1 million increase in planned maintenance costs of PSE's generating facilities and a settlement related to Colstrip, a $10.0 million increase in administrative and general expenses which included increases in maintenance of electric general plant, company facility leases, insurance and liability claims, a $10.0 million increase in electric transmission and distribution expenses, a $9.9 million increase in gas operations and distribution expenses and a $5.5 million increase in customer service expenses including bad debt expense.

**Depreciation and amortization** expense increased $32.9 million in 2008 as compared to 2007. Costs in 2007 included the benefit of the deferral of Goldendale ownership and operating costs of $10.8 million which, had it not been included, would have resulted in an increase to depreciation and amortization expense of $22.1 million for 2008 as compared to 2007. The Goldendale deferral of ownership and operating costs ceased to be effective September 1, 2007, when PSE was authorized to begin recovering the costs in rates.

**Conservation amortization** increased $21.7 million in 2008 as compared to 2007 due to higher authorized recovery of electric and natural gas conservation expenditures. Conservation amortization is a pass-through tariff item with no impact on earnings.

**Taxes other than income taxes** decreased $3.5 million in 2008 net of revenue sensitive taxes as compared to 2007 primarily due to a true-up of 2007 property taxes recorded in 2008.

**Other Income, Other Expenses, Interest Expense and Income Tax Expense.** The table below sets forth significant changes for PSE from 2007 to 2008.

| (DOLLARS IN MILLIONS)<br>TWELVE MONTHS ENDED DECEMBER 31 | 2008 | 2007 | CHANGE | PERCENT CHANGE |
|---|---|---|---|---|
| Other income | $ 33.2 | $ 28.9 | $ 4.3 | 14.9 % |
| Interest expense | 194.8 | 206.5 | (11.7 ) | (5.7 ) |
| Income tax expense | 60.9 | 74.2 | (13.3 ) | (17.9 ) |

**Other income** increased $4.3 million for 2008 as compared to 2007 due primarily to an increase in Allowance for Funds Used During Construction (AFUDC) of $3.7 million and an increase of $1.9 million in electric conservation incentive, which was partially offset by a decrease in life insurance gains.

**Interest expense** decreased $11.7 million for 2008 as compared to 2007. The decrease is due primarily to the decrease in average debt outstanding as a result of an equity issuance in December 2007 and lower average interest rates on outstanding debt.

**Income tax expense** decreased $13.3 million in 2008 as compared to 2007. The effective tax rate was lower primarily due to higher production tax credits associated with the production of wind-powered energy (PTCs). The PTCs for 2008 were $23.0 million as compared to $20.2 million in 2007.

**2007 COMPARED TO 2006**

**PUGET SOUND ENERGY**

**Energy Margins.** The following table displays the details of electric margin changes from 2006 to 2007. 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 2007 | 2006 | CHANGE | PERCENT CHANGE |
|---|---|---|---|---|
| Electric operating revenue[1] | $ 1,997.8 | $ 1,777.7 | $ 220.1 | 12.4 % |
| Less: Other electric operating revenue | (41.9) | (51.8) | 9.9 | 19.1 |
| Add: Other electric operating revenue – gas supply resale | 1.5 | 16.4 | (14.9) | (90.9) |
| Total electric revenue for margin | 1,957.4 | 1,742.3 | 215.1 | 12.3 |
| Adjustments for amounts included in revenue: | | | | |
| Pass-through tariff items | (43.0) | (35.9) | (7.1) | (19.8) |
| Pass-through revenue-sensitive taxes | (133.6) | (117.4) | (16.2) | (13.8) |
| Net electric revenue for margin | 1,780.8 | 1,589.0 | 191.8 | 12.1 |
| Minus power costs: | | | | |
| Purchased electricity[1] | (895.6) | (917.8) | 22.2 | 2.4 |
| Electric generation fuel[1] | (143.4) | (97.3) | (46.1) | (47.4) |
| Residential exchange[1] | 52.4 | 163.6 | (111.2) | (68.0) |
| Total electric power costs | (986.6) | (851.5) | (135.1) | (15.9) |
| Electric margin[2] | $ 794.2 | $ 737.5 | $ 56.7 | 7.7 % |

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 $56.7 million in 2007 as compared to 2006. The increase was primarily due to recovery of ownership and operating costs of new generation facilities included in the PCORC rate increase of 3.7% effective September 1, 2007 and in the general rate decrease of 1.3% effective January 13, 2007, which increased electric margin by $46.2 million. The increase in electric margin also benefited from higher production of low cost hydroelectric power and company-owned generating facilities which resulted in a $10.3 million increase in electric margin due to overrecovery of power costs in 2007 as compared to 2006 and a $16.4 million increase in margin due to an increase in retail sales volume of 2.5%. These increases were slightly offset by a $16.9 million decrease in margin due to an increase of PTCs provided to customers. PTCs provided to customers through lower rates are recovered through a lower effective tax rate.

The following table displays the details of gas margin changes from 2006 to 2007. Gas margin is natural gas sales to retail and transportation customers less pass-through tariff items and revenue-sensitive taxes, and the cost of natural gas purchased, including natural gas transportation costs to bring natural gas to PSE's service territory.

| (DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31 | GAS MARGIN 2007 | 2006 | CHANGE | PERCENT CHANGE |
|---|---|---|---|---|
| Gas operating revenue[1] | $ 1,208.0 | $ 1,120.1 | $ 87.9 | 7.8% |
| Less: Other gas operating revenue | (17.4) | (16.5) | (0.9) | (5.5) |
| Total gas revenue for margin | 1,190.6 | 1,103.6 | 87.0 | 7.9 |
| Adjustments for amounts included in revenue: | | | | |
| Pass-through tariff items | (9.6) | (7.1) | (2.5) | (35.2) |
| Pass-through revenue-sensitive taxes | (95.2) | (86.3) | (8.9) | (10.3) |
| Net gas revenue for margin | 1,085.8 | 1,010.2 | 75.6 | 7.5 |
| Minus purchased gas costs[1] | (762.1) | (723.2) | (38.9) | (5.4) |
| Gas margin[2] | $ 323.7 | $ 287.0 | $ 36.7 | 12.8% |

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 $36.7 million in 2007 as compared to 2006. Gas margin increased $26.7 million due to a 2.8% general rate increase effective January 13, 2007 which increased gas margin by approximately 9.8% as a result of recovering ownership and operating costs of natural gas plant. In addition, an increase of 3.8% in natural gas therm volume sales increased gas margin $11.0 million. These increases were slightly offset by a change in customer usage and pricing which resulted in a $1.0 million decrease to margin.

**Electric Operating Revenues.** The table below sets forth changes in electric operating revenues for PSE from 2006 to 2007.

| (Dollars in Millions) Twelve Months Ended December 31 | 2007 | 2006 | Change | Percent Change |
|---|---|---|---|---|
| Electric operating revenues: | | | | |
| Residential sales | $ 951.1 | $ 788.2 | $ 162.9 | 20.7% |
| Commercial sales | 748.8 | 702.8 | 46.0 | 6.5 |
| Industrial sales | 105.2 | 103.0 | 2.2 | 2.1 |
| Other retail sales, including unbilled revenue | 31.7 | 35.4 | (3.7) | (10.5) |
| Total retail sales | 1,836.8 | 1,629.4 | 207.4 | 12.7 |
| Transportation sales | 9.4 | 11.5 | (2.1) | (18.3) |
| Sales to other utilities and marketers | 109.7 | 85.0 | 24.7 | 29.1 |
| Other | 41.9 | 51.8 | (9.9) | (19.1) |
| Total electric operating revenues | $ 1,997.8 | $ 1,777.7 | $ 220.1 | 12.4% |

Electric retail sales increased $207.4 million for 2007 as compared to 2006 due primarily to a decrease in the benefits of the REP credited to residential and small farm customers, which reduced electric operating revenue by $54.9 million in 2007 as compared to $171.3 million in 2006 (an increase in revenue of $116.4 million). The credit also reduced power costs by a corresponding amount with no impact on earnings. The PCORC rate increases of July 1, 2006 and September 1, 2007 offset by the electric general rate decrease of January 13, 2007 increased electric retail sales along with an increase in retail sales volumes. The electric tariff changes increased electric operating revenues by $59.3 million for 2007 as compared to 2006. Retail electricity usage increased 535,301 MWh or 2.5% for 2007 as compared to the same period in 2006, which resulted in an increase of approximately $41.2 million in electric operating revenue. The increase in electricity usage was related in part to 2.0% higher average number of customers served in 2007 as compared to 2006. These increases were offset by a decrease in revenue related to production tax credits of $30.8 million given to customers in 2007 as compared to a credit of $13.9 million in 2006.

Transportation sales decreased $2.1 million in 2007 as compared to 2006 as a result of transportation customers balancing their scheduled load. During 2006, transportation customers purchased power in excess of their scheduled load whereas for the same period in 2007, the scheduled load was less than actual usage. This decrease was offset by an increase in sales volume of 39,988 MWh or 1.9%.

Sales to other utilities and marketers increased $24.7 million for 2007 as compared to 2006 due to an increase in sales volume of 185,206 MWh or 9.0%, which resulted in a $9.0 million increase. In 2007, PSE's average wholesale sales price to other utilities and marketers increased $0.0076 as compared to 2006 which resulted in an increase of approximately $15.7 million.

Other electric revenues decreased $9.9 million for 2007 as compared to 2006 primarily due to gains from natural gas financial hedges on natural gas sold to third parties in 2006 that did not recur in 2007.

The following electric rate changes were approved by the Washington Commission in 2007 and 2006:

| Type of Rate Adjustment | Effective Date | Average Percentage Increase (Decrease) in Rates | Annual Increase (Decrease) in Revenues (Dollars in Millions) |
|---|---|---|---|
| Power Cost Only Rate Case | July 1, 2006 | 5.9 % | $ 45.3 [1] |
| Electric General Rate Case | January 13, 2007 | (1.3)% | (22.8) |
| Power Cost Only Rate Case | September 1, 2007 | 3.7 % | 64.7 |

[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 2006 to 2007.

| (DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31 | 2007 | 2006 | CHANGE | PERCENT CHANGE |
|---|---|---|---|---|
| Gas operating revenues: | | | | |
| Residential sales | $ 756.2 | $ 697.6 | $ 58.6 | 8.4% |
| Commercial sales | 363.0 | 335.7 | 27.3 | 8.1 |
| Industrial sales | 57.7 | 57.1 | 0.6 | 1.1 |
| Total retail sales | 1,176.9 | 1,090.4 | 86.5 | 7.9 |
| Transportation sales | 13.7 | 13.3 | 0.4 | 3.0 |
| Other | 17.4 | 16.4 | 1.0 | 6.1 |
| Total gas operating revenues | $ 1,208.0 | $ 1,120.1 | $ 87.9 | 7.8% |

Gas retail sales increased $86.5 million for 2007 as compared to 2006 due to the approval of a 2.8% general natural gas rate increase effective January 13, 2007, higher PGA mechanism rates and increased customer natural gas usage. The natural gas general rate increase provided an additional $26.9 million in gas revenues for 2007 as compared to 2006. The approval by the Washington Commission of the PGA mechanism rate increase effective October 1, 2006 increased rates by 10.2% annually and then the approval of a rate decrease effective October 1, 2007 decreased rates 13.0% annually. The PGA mechanism passes through to customers increases or decreases in the natural 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 natural gas pipeline transportation costs. PSE's gas margin and net income are not affected by changes under the PGA mechanism. For 2007, the effects of the PGA mechanism rate changes provided a net increase of $9.7 million in gas operating revenues. The remaining increase in gas retail revenues was primarily due to higher gas sales of 41.6 million therms or $43.3 million for 2007 as compared to 2006, which was related in part to a 2.6% increase in customers.

The following natural gas rate changes were approved by the Washington Commission in 2007 and 2006:

| TYPE OF RATE ADJUSTMENT | EFFECTIVE DATE | AVERAGE PERCENTAGE INCREASE (DECREASE) IN RATES | ANNUAL INCREASE (DECREASE) IN REVENUES (DOLLARS IN MILLIONS) |
|---|---|---|---|
| Purchased Gas Adjustment | October 1, 2006 | 10.2 % | $ 95.1 |
| Gas General Rate Case | January 13, 2007 | 2.8 % | 29.5 |
| Purchased Gas Adjustment | October 1, 2007 | (13.0 )% | (148.1) |

**Operating Expenses.** The table below sets forth significant changes in operating expenses for PSE from 2006 to 2007.

| (DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31 | 2007 | 2006 | CHANGE | PERCENT CHANGE |
|---|---|---|---|---|
| Purchased electricity | $ 895.6 | $ 917.8 | $ (22.2) | (2.4)% |
| Electric generation fuel | 143.4 | 97.3 | 46.1 | 47.4 |
| Residential exchange | (52.4) | (163.6) | 111.2 | 68.0 |
| Purchased gas | 762.1 | 723.2 | 38.9 | 5.4 |
| Unrealized (gain)/loss on derivative instruments | (2.7) | 0.1 | (2.8) | * |
| Utility operations and maintenance | 403.7 | 354.6 | 49.1 | 13.8 |
| Non-utility expense and other | 12.4 | 4.5 | 7.9 | 175.6 |
| Depreciation and amortization | 279.2 | 262.3 | 16.9 | 6.4 |
| Conservation amortization | 40.0 | 32.3 | 7.7 | 23.8 |
| Taxes other than income taxes | 288.5 | 255.8 | 32.7 | 12.8 |

* *Percent change not applicable or meaningful*

**Purchased electricity** expenses decreased $22.2 million in 2007 as compared to 2006 due primarily to a decrease in purchased power of 983,297 MWh, or 5.5%, resulting in a decrease of $46.6 million, offset by an increase in wholesale market prices which caused an increase of $16.7 million. Contributing to the decrease in purchased power was the increase in electric generation at Company-owned facilities. The power cost adjustment (PCA) mechanism reflected a $9.4 million decrease in the deferral of power costs for 2007 as compared to 2006 due to an increase in the overrecovery of allowable power costs shared with customers due to lower power costs in 2007 as compared to 2006. Transmission and other power supply expenses increased by $17.1 million in 2007 as compared to 2006 due in part to increased kilowatt hour (kWh) sales to customers which increased transmission costs.

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 $46.1 million in 2007 as compared to 2006 primarily due to the addition of Goldendale in 2007 which contributed $32.7 million to the cost of fuel and an increase of $8.7 million due to higher volumes of electricity generated at Colstrip which increased coal costs in 2007 as compared to 2006. In addition, higher cost of natural gas fuel at PSE's other combustion turbines contributed $4.7 million in 2007 as compared to 2006.

**Residential exchange credits** associated with the Residential Purchase and Sale Agreement with the BPA decreased $111.2 million in 2007 as compared to 2006 as a result of lower residential and small farm customer electric credit in rates effective October 1, 2006. The residential exchange credit provided to residential and small farm customers was suspended effective June 7, 2007 due to an adverse ruling from the Ninth Circuit which states that BPA actions in entering into residential exchange settlement agreements with investor owned utilities were not in accordance with the law. 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 $38.9 million in 2007 as compared to 2006 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 natural gas costs, and defer, as a receivable or liability, any natural gas costs that exceed or fall short of this expected natural gas cost amount in PGA mechanism rates, including accrued interest. The PGA mechanism payable balance at December 31, 2007 was $77.9 million as compared to a receivable balance at December 31, 2006 of $39.8 million. PSE is authorized by the Washington Commission to accrue carrying costs on PGA receivable and payable balances. A receivable balance in the PGA mechanism reflects an underrecovery of market natural gas cost through rates. A payable balance reflects overrecovery of market natural gas cost through rates.

**Unrealized gain on derivative instruments** increased $2.8 million in 2007 as compared to 2006 primarily as a result of the unrealized gain related to a physical natural gas supply contract for PSE's electric generating facilities offset by the settlement of a portion of the gain. The mark-to-market gain or loss on the physical natural gas supply contracts is the difference between the forward market price of natural gas and the contract price for natural gas based on volumes purchased. As the contracts near termination, the gain or loss will continue to reverse due to settlement of the contract on a monthly basis and the mark-to-market value will decrease as long as the price for natural gas is at or near the current forward market price.

**Utility operations and maintenance** expense increased $49.1 million in 2007 as compared to 2006 primarily due to higher operating and maintenance costs of $16.0 million at PSE's generating facilities. The increase in costs at PSE's generating facilities is primarily due to the addition of Wild Horse, which began operations on December 22, 2006, and Goldendale, which was acquired during February 2007. Wild Horse operations and maintenance expense is fully recovered in rates and beginning September 1, 2007, Goldendale is fully recovered in rates. Customer service and support services costs increased $19.7 million due to higher costs associated with salaries, benefits, consultants and bad debt reserve. The balance of the increases was the result of infrastructure reliability work performed on the utility's transmission and distribution systems.

**Non-utility expense and other** increased $7.9 million in 2007 as compared to 2006 primarily due to an increase in PSE's long-term share-based incentive plan costs based on an increase in performance modifiers.

**Depreciation and amortization** expense increased $16.9 million in 2007 as compared to 2006, which included the benefit of the deferral of Goldendale ownership and operating costs of $10.8 million which, had it not been included, would have resulted in an increase to depreciation and amortization expense of $27.7 million for 2007 as compared to 2006. Also contributing to the increase in depreciation and amortization was $13.5 million from placing Wild Horse into service on

December 16, 2006, $2.7 million from placing Goldendale into service on February 22, 2007 and $11.5 million from other depreciable property placed into service in 2007 and 2006. On August 2, 2007, the Washington Commission approved a PCORC settlement agreement filed July 5, 2007 finding the acquisition of Goldendale to be prudent. The Goldendale deferral of ownership and operating costs ceased to be effective September 1, 2007, when PSE was authorized to begin recovering the costs in rates.

**Conservation amortization** increased $7.7 million in 2007 as compared to 2006 due to higher authorized recovery of electric and natural gas conservation expenditures. Conservation amortization is a pass-through tariff item with no impact on earnings.

**Taxes other than income taxes** increased $32.7 million in 2007 as compared to 2006 primarily due to a property tax settlement in 2006 with the Washington State Department of Revenue which resulted in lower property valuations in 2006. The increases also reflect an additional plant placed in service as well as revenue sensitive taxes due to increased revenue.

**Other Income, Other Expenses, Interest Expense and Income Tax Expense.** The table below sets forth significant changes for PSE from 2006 to 2007.

| (DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31 | 2007 | 2006 | CHANGE | PERCENT CHANGE |
|---|---|---|---|---|
| Interest expense | $ 206.5 | $ 168.9 | $ 37.6 | 22.3 % |
| Income tax expense | 74.2 | 98.7 | (24.5) | (24.8) |

**Interest expense** increased $37.6 million for 2007 as compared to 2006. The increase was driven primarily by additional debt financing in 2007 during which average balances were higher than 2006 levels as a result of financing the Company's construction and plant acquisition projects and higher interest rates. The increase was also driven by more favorable pricing on natural gas purchases in 2007 which resulted in the interest-bearing PGA transferring from a receivable balance in 2006 to a payable balance in 2007.

**Income tax expense** decreased $24.5 million in 2007 as compared to 2006. The effective tax rate was lower due to higher production tax credits associated with the production of wind-powered energy (PTCs). The PTCs for 2007 were $20.2 million as compared to $7.0 million in 2006. These additional credits were made available due to the addition of Wild Horse, which was placed in service in December 2006. In addition, income tax expense benefited from a true-up of the prior year federal income tax provision which resulted in a benefit in 2007 versus an expense in 2006.

## 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 | 2009 | 2010-2011 | 2012-2013 | 2014 & THEREAFTER |
| Long-term debt including interest [1] | $ 6,074.0 | $ 328.3 | $ 775.8 | $ 272.0 | $ 4,697.9 |
| Short-term debt including interest [2] | 964.7 | 964.7 | -- | -- | -- |
| Mandatorily redeemable preferred stock [3] | 2.0 | 2.0 | -- | -- | -- |
| Service contract obligations | 383.9 | 67.1 | 126.7 | 79.4 | 110.7 |
| Non-cancelable operating leases | 211.6 | 86.2 | 26.6 | 24.4 | 74.4 |
| Fredonia combustion turbines lease [4] | 47.3 | 47.3 | -- | -- | -- |
| Energy purchase obligations | 5,896.0 | 1,105.8 | 1,677.2 | 785.5 | 2,327.5 |
| Contract initiation payment/collateral requirement | 18.5 | -- | 18.5 | -- | -- |
| Financial hedge obligations | 111.5 | 63.9 | 47.6 | -- | -- |
| Purchase obligations | 174.1 | 74.6 | 7.1 | 18.7 | 73.7 |
| Non-qualified pension and other benefits funding and payments | 52.1 | 5.8 | 8.8 | 9.9 | 27.6 |
| Total contractual cash obligations | $ 13,935.7 | $ 2,745.7 | $ 2,688.3 | $ 1,189.9 | $ 7,311.8 |

| **Puget Energy** | | AMOUNT OF COMMITMENT EXPIRATION PER PERIOD | | | |
|---|---|---|---|---|---|
| COMMERCIAL COMMITMENTS (DOLLARS IN MILLIONS) | TOTAL | 2009 | 2010-2011 | 2012-2013 | 2014 & THEREAFTER |
| Credit agreement - available [5] | $ 346.7 | $ 346.7 | $ -- | $ -- | $ -- |
| Receivables securitization facility [6] | 42.0 | 42.0 | -- | -- | -- |
| Energy operations letter of credit | 6.6 | 6.6 | -- | -- | -- |
| Letter of credit | 20.0 | 20.0 | -- | -- | -- |
| Total commercial commitments | $ 415.3 | $ 415.3 | $ -- | $ -- | $ -- |

The following are Puget Energy's aggregate consolidated (including PSE) commercial commitments as of immediately after the effective time of the merger on February 6, 2009:

| **Puget Energy**<br>COMMERCIAL COMMITMENTS<br>(DOLLARS IN MILLIONS) | TOTAL | AMOUNT OF COMMITMENT EXPIRATION PER PERIOD<br>2009 | 2010-2011 | 2012-2013 | 2014 & THEREAFTER |
|---|---|---|---|---|---|
| Puget Energy capital expenditure facility [7] | $ 742.0 | $ -- | $ -- | $ -- | $ 742.0 |
| PSE working capital facility [7] | 330.0 | -- | -- | -- | 330.0 |
| PSE capital expenditure facility [7] | 400.0 | -- | -- | -- | 400.0 |
| PSE energy hedging facility [7] | 320.0 | -- | -- | -- | 320.0 |
| PSE energy operations letter of credit | 6.6 | 6.6 | -- | -- | -- |
| PSE energy hedging letter of credit | 30.0 | 30.0 | -- | -- | -- |
| Total commercial commitments | $ 1,828.6 | $ 36.6 | $ -- | $ -- | $ 1,792.0 |

1 *At the close of the merger on February 6, 2009, Puget Energy executed a five-year term loan of $1.2 billion and a $258 million draw under the Puget Energy capital expenditure facility.*

2 *At the close of the merger on February 6, 2009, all of the credit facilities of PSE were repaid and terminated and were replaced by new facilities as described in the liquidity facilities section. The $964.7 million of short-term debt outstanding under PSE's credit facilities was replaced with a $70.0 million draw under a new PSE short-term working capital credit facility.*

3 *The mandatorily redeemable preferred stock was defeased on February 5, 2009 and will be redeemed on March 13, 2009.*

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

5 *As of December 31, 2008, PSE had a total $1.2 billion in credit facilities available. At December 31, 2008, PSE had available unsecured credit agreements in the amount of $500.0 million and $350.0 million, each expiring in April 2012. On February 6, 2009 in connection with the merger, these credit agreements were terminated and repaid in full.*

6 *At December 31, 2008, PSE had available a $200.0 million receivables securitization facility, expiring in December 2010. On February 6, 2009 in connection with the merger, the receivable securitization facility was terminated.*

7 *See the discussion below on Puget Energy and Puget Sound Energy credit facilities.*

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

| **Puget Sound Energy**<br>CONTRACTUAL OBLIGATIONS<br>(DOLLARS IN MILLIONS) | TOTAL | PAYMENTS DUE PER PERIOD<br>2009 | 2010-2011 | 2012-2013 | 2014 & THEREAFTER |
|---|---|---|---|---|---|
| Long-term debt including interest | $ 6,074.0 | $ 328.3 | $ 775.8 | $ 272.0 | $ 4,697.9 |
| Short-term debt including interest [1] | 990.8 | 990.8 | -- | -- | -- |
| Mandatorily redeemable preferred stock [2] | 2.0 | 2.0 | -- | -- | -- |
| Service contract obligations | 383.9 | 67.1 | 126.7 | 79.4 | 110.7 |
| Non-cancelable operating leases | 211.6 | 86.2 | 26.6 | 24.4 | 74.4 |
| Fredonia combustion turbines lease [3] | 47.3 | 47.3 | -- | -- | -- |
| Energy purchase obligations | 5,896.0 | 1,105.8 | 1,677.2 | 785.5 | 2,327.5 |
| Contract initiation payment/collateral requirement | 18.5 | -- | 18.5 | -- | -- |
| Financial hedge obligations | 111.5 | 63.9 | 47.6 | -- | -- |
| Purchase obligations | 174.1 | 74.6 | 7.1 | 18.7 | 73.7 |
| Non-qualified pension and other benefits funding and payments | 52.1 | 5.8 | 8.8 | 9.9 | 27.6 |
| Total contractual cash obligations | $ 13,961.8 | $ 2,771.8 | $ 2,688.3 | $ 1,189.9 | $ 7,311.8 |

**Puget Sound Energy**. The following are PSE's aggregate commercial commitments as of December 31, 2008:

| **Puget Sound Energy**<br>COMMERCIAL COMMITMENTS<br>(DOLLARS IN MILLIONS) | TOTAL | AMOUNT OF COMMITMENT EXPIRATION PER PERIOD<br>2009 | 2010-2011 | 2012-2013 | 2014 & THEREAFTER |
|---|---|---|---|---|---|
| Credit agreement - available [4] | $ 346.7 | $ 346.7 | $ -- | $ -- | $ -- |
| Receivables securitization facility [5] | 42.0 | 42.0 | -- | -- | -- |
| Energy operations letter of credit | 6.6 | 6.6 | -- | -- | -- |
| Letter of credit | 20.0 | 20.0 | -- | -- | -- |
| Total commercial commitments | $ 415.3 | $ 415.3 | $ -- | $ -- | $ -- |

The following are PSE's aggregate consolidated commercial commitments as of immediately after the effective time of the merger on February 6, 2009:

| **Puget Sound Energy**<br>COMMERCIAL COMMITMENTS<br>(DOLLARS IN MILLIONS) | TOTAL | AMOUNT OF COMMITMENT EXPIRATION PER PERIOD<br>2009 | 2010-2011 | 2012-2013 | 2014 & THEREAFTER |
|---|---|---|---|---|---|
| Working capital facility [6] | $ 330.0 | $ -- | $ -- | $ -- | $ 330.0 |
| Capital expenditure facility [6] | 400.0 | -- | -- | -- | 400.0 |
| Energy hedging facility [6] | 320.0 | -- | -- | -- | 320.0 |
| Energy operations letter of credit | 6.6 | 6.6 | -- | -- | -- |
| Energy hedging letter of credit | 30.0 | 30.0 | -- | -- | -- |
| Total commercial commitments | $ 1,086.6 | $ 36.6 | $ -- | $ -- | $ 1,050.0 |

1 *See note 2 above.*
2 *See note 3 above.*
3 *See note 4 above.*
4 *See note 5 above.*
5 *See note 6 above.*
6 *See note 7 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. On November 14, 2008, GE Capital Commercial notified PSE of its intention to cancel the lease effective January 14, 2009. PSE is currently evaluating whether to sell or purchase the combustion turbines, with a purchase being the most likely outcome in 2009. Payments under the lease vary with changes in the London Interbank Offered Rate (LIBOR). At December 31, 2008, PSE's outstanding balance under the lease was $45.5 million. The expected residual value under the lease is $42.6 million. In the event the equipment is sold to a third party upon termination of the lease and the aggregate sales proceeds are less than the unamortized value of the equipment, PSE would be required to pay the lessor contingent rent in an amount equal to the deficiency up to a maximum of 87% of the unamortized value of the equipment.

## UTILITY CONSTRUCTION PROGRAM

PSE's construction programs for generating facilities, the electric transmission system and the natural gas and electric distribution system are designed to meet continuing customer growth and to support reliable energy delivery. The cash flow construction expenditures, excluding equity AFUDC and customer refundable contributions was $841.6 million in 2008. The anticipated utility construction expenditures, excluding AFUDC, for 2009, 2010 and 2011 are:

| CAPITAL EXPENDITURE PROJECTIONS<br>(DOLLARS IN MILLIONS) | 2009 | 2010 | 2011 |
|---|---|---|---|
| Energy delivery, technology and facilities | $ 687 | $ 840 | $ 786 |
| New resources | 234 | 621 | 346 |
| Total expenditures | $ 921 | $ 1,461 | $ 1,132 |

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.

**CAPITAL RESOURCES**

**CASH FROM OPERATIONS**

Cash generated from operations for 2008 was $536.6 million, which is 58.8% of the $912.1 million used for utility construction expenditures and other capital expenditures. For 2007, cash generated from operations was $564.0 million which is 72.2% of the $780.7 million used for utility construction expenditures and other capital expenditures.

The overall cash generated from operating activities for 2008 decreased $27.6 million as compared to 2007. The decrease was primarily the result of timing differences as a result of the recent volatility in natural gas prices which resulted in actual natural gas costs incurred exceeding the amount received from customers in 2008 resulting in a $186.7 million decrease in cash from operations. At the end of 2006, PSE had under-recovered natural gas costs as costs were higher than customer rates. In 2007, rates increased to recover the higher natural gas costs in 2006 while natural gas costs fell below the rate of recovery resulting in over recovery of natural gas costs of $117.7 million. Overrecovery of natural gas costs continued through most of 2008 until new natural gas rates came into effect in November 2008, resulting in a net PGA cash outflow of $69.0 million. Also due to higher natural gas costs in 2008, fuel and gas inventory costs increased $36.4 million as compared to the same period in 2007. The PSE pension plan required funding of $24.9 million in 2008 as a result of declining financial market performance.

The decrease in cash generated from operating activities for 2008 as compared to 2007 was partially offset by less cash paid to accounts payable of $74.1 million and a decrease in deferred storm costs of $32.6 million which were primarily due to 2006 storm costs paid in 2007. In April 2008, BPA and PSE signed an agreement regarding the suspended REP to which BPA settled PSE's outstanding REP balance, which resulted in a $66.0 million increase in cash from operating activities. The Company received a net $42.3 million in income tax refunds further offsetting the overall cash decrease in operating activities.

**FINANCING PROGRAM**

Financing utility construction requirements and operational needs are largely 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 climate 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 credit facilities, its electric and natural gas mortgage indentures and certain loan agreements. Under the most restrictive tests, as of the time of the merger on February 6, 2009, PSE could issue:

- approximately $1.1 billion of additional first mortgage bonds under PSE's electric mortgage indenture based on approximately $1.9 billion 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, 2008; and
- approximately $564.0 million of additional first mortgage bonds under PSE's natural gas mortgage indenture based on approximately $940.0 million of natural 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, 2008.

At December 31, 2008, PSE had approximately $4.9 billion in electric and natural gas ratebase to support the interest coverage ratio limitation test for net earnings available for interest.

## CREDIT RATINGS

Neither Puget Energy nor PSE has any debt outstanding that would accelerate debt maturity upon a credit rating downgrade. 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 Puget Energy's and PSE's credit facilities, the borrowing costs and commitment fees increase as their respective credit 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-2/P-3 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 natural 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.

On January 16, 2009, Standard & Poor's Rating Services raised its corporate credit rating on PSE while it lowered its corporate credit rating for Puget Energy. At the same time it removed both companies from its watch list for negative implications citing a stable outlook. The rating actions reflected the anticipated completion of the acquisition of Puget Energy and PSE by Puget Holdings, which occurred on February 6, 2009.

On February 2, 2009, Moody's Investors Service downgraded the Issuer Rating of Puget Energy to Ba2 from Ba1 and affirmed the long-term ratings of PSE. The ratings outlook for both companies is stable.

The ratings of Puget Energy and PSE, as of February 20, 2009, were:

| | Ratings | |
|---|---|---|
| | Standard & Poor's [1] | Moody's [2] |
| **Puget Sound Energy, Inc.** | | |
| Corporate credit/issuer rating | BBB | Baa3 |
| Senior secured debt | A- | Baa2 |
| Junior subordinated notes | BB+ | Ba1 |
| Preferred stock | BB+ | Ba2 |
| Commercial paper | A-2 | P-3 |
| Bank facilities | BBB | Baa3 |
| Ratings outlook | Stable | Stable |
| **Puget Energy, Inc.** | | |
| Corporate credit/issuer rating | BB+ | Ba2 |
| Bank facilities | BB+ | Ba2 |
| Ratings Outlook | Stable | Stable |

1 *On January 16, 2009, Standard & Poor's Ratings Service upgraded PSE's corporate and other credit ratings, while downgrading Puget Energy's corporate credit rating. It also removed all the ratings from negative watch, citing a stable outlook.*

2 *On February 2, 2009, Moody's Investors Service affirmed the long-term ratings of PSE, while downgrading PSE short-term rating for commercial paper to P-3 and the Issuer Rating of Puget Energy to Ba2.*

## SHELF REGISTRATIONS, LONG-TERM DEBT AND COMMON STOCK ACTIVITY

In connection with the closing of the merger, all shelf registration statements of Puget Energy were terminated and the shelf registration of PSE, which was originally filed on March 16, 2006, was amended and now provides for the offering of senior notes of PSE, secured by first mortgage bonds and unsecured debentures of PSE.

The PSE registration statement is valid for three years from the date of the original filing, or until March 16, 2009, and does not specify the amount of securities that PSE may offer. The Company is subject to restrictions under PSE's indentures on the amount of first mortgage bonds that PSE may issue.

On June 1, 2007, PSE redeemed the remaining 8.231% Capital Trust Preferred Securities (classified on the balance sheet as Junior Subordinated Debentures of the Corporation Payable to a Subsidiary Trust Holding Mandatorily Redeemable Preferred Securities and referred to herein as "Securities"). The purpose of the redemption was to help reduce interest costs by retiring higher cost debt. The remaining $37.8 million of the Securities outstanding were redeemed on June 1, 2007 at a 4.12% premium, or $39.3 million, plus accrued interest on the redemption date.

On June 4, 2007, PSE issued $250.0 million of Junior Subordinated Notes (Notes) due June 2067. The Notes bear a fixed rate of interest of 6.974% for the first ten and a half years with interest payable semiannually in May and November of each year, after which the notes will bear a variable rate of interest (3-month LIBOR plus 2.35%). Proceeds were used to fund the redemption of the remaining $37.8 million 8.2% Securities and to repay short-term debt. The Notes are structured to be treated as debt by the Internal Revenue Service (IRS), yet they are considered to contain equity-like characteristics by the credit rating agencies. In addition, the Notes contain a call option feature and are callable in whole or in part by PSE on or after June 1, 2017. They are presented on the balance sheet as a separate line item in the redeemable securities and long-term debt.

Puget Energy completed the sale of 12.5 million shares of common stock pursuant to the stock purchase agreement the Company announced on October 25, 2007, among Puget Energy and the Consortium. The Consortium paid an aggregate offering price of $295.9 million. The securities were sold in a private placement, without registration under the Securities Act of 1933. Puget Energy used the net proceeds from the issuance to invest in PSE for capital expenditures, debt redemption and working capital.

On January 23, 2009, PSE completed a $250.0 million issuance of senior secured notes. The notes have a term of seven years and an interest rate of 6.75%. Net proceeds from the issue were used to repay short-term debt incurred to partially fund the utility's capital expenditures.

#### 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 has not been significantly impacted by the recent disruption in the credit environment.

#### PUGET ENERGY CREDIT FACILITIES

As of December 31, 2008, Puget Energy had no short-term credit facilities. Effective with the close of the merger on February 6, 2009, Puget Energy has a $1.225 billion five-year term loan and a $1.0 billion credit facility for funding capital expenditures. These facilities mature in 2014, contain similar terms and conditions, and are syndicated among numerous committed banks. The agreements provide Puget Energy with the ability to borrow at different interest rate options and include variable fee levels. Borrowings may be at the bank's prime rate or at floating rates based on LIBOR plus a spread that is based upon the Puget Energy's credit rating. As of February 6, 2009, the term loan was fully drawn at $1.225 billion and $258.0 million was outstanding under the $1.0 billion facility.

#### PSE CREDIT FACILITIES

**Credit Agreements.** Effective immediately after the merger on February 6, 2009, PSE has three committed unsecured revolving credit facilities that provide, in aggregate, $1.15 billion in short-term borrowing capability. These new facilities include a $400.0 million credit agreement for working capital needs, a $400.0 million credit facility for funding capital expenditures and a $350.0 million facility to support other working capital and energy hedging activities.

These facilities mature in 2014 and each contain similar terms and conditions and are syndicated among numerous committed banks. The agreements provide PSE with the ability to borrow at different interest rate options and include variable fee levels. The bank credit agreements allow PSE to borrow at the bank's prime rate or to make floating rate advances at LIBOR plus a spread that is based upon PSE's credit rating. The $400.0 million working capital facility and $350.0 million credit agreement to support energy hedging allow for issuing standby letters of credit up to the entire amount of the credit agreements. The $400.0 million working capital facility also serves as a backstop for PSE's commercial paper program.

At the close of the merger on February 6, 2009, PSE had borrowed $70.0 million on the $400.0 million working capital facility and had a $30.0 million letter of credit outstanding under the $350.0 million facility. In addition to the credit agreements, PSE had a $6.6 million letter of credit through a bank in support of a long-term transmission contract.

**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 receivables securitization facility of PSE Funding, a PSE subsidiary. If there are no borrowings under these facilities, interest on the note is LIBOR plus a spread.

Absent such borrowings, interest is charged at a base rate. At December 31, 2008, the outstanding balance of the Note was $26.1 million. The outstanding balance and the related interest under the Note are eliminated by Puget Energy upon consolidation of PSE's financial statements. This Note is unaffected by the February 6, 2009 merger.

### OTHER

**IRS Audit.** The Company's tax returns are routinely audited by federal, state and city tax authorities. In May 2006, the IRS completed its examination of the company's 2001, 2002 and 2003 federal income tax returns. In June 2008, the IRS completed its examination of the company's 2004 and 2005 federal income tax returns. The Company formally appealed the IRS audit adjustment relating 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.

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.

During 2007, the IRS national office established settlement guidelines which the appeals office uses in reaching settlements with taxpayers. The effect of the settlement guidelines shifts some of the benefits claimed in 2001 through 2004 into 2005 and 2006. As a result, through 2008, the Company accrued interest in the amount of $7.0 million.

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. On November 5, 2008, PSE filed an accounting petition for a Washington Commission order authorizing the deferral and recovery of interest due the IRS for tax years 2001 to 2006 along with carrying costs incurred in connection with the interest due. In its 2003 tax return, the Company claimed a deduction for a portion of the California Independent System Operator (CAISO) receivable. Upon examination, the IRS claimed that the deduction was not valid for the 2003 tax year. The Company formally appealed. In appeals, the Company and the IRS agreed to move the deduction from 2003 to 2005. This resulted in a net interest charge of $1.4 million.

**Tenaska Disallowance.** The Washington Commission issued an order on May 13, 2004 determining that PSE did not prudently manage natural 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 $6.4 million, $7.8 million and $9.0 million in 2008, 2007 and 2006, 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.

The Washington Commission confirmed that if the Tenaska natural gas costs are deemed prudent, PSE will recover the full amount of actual natural gas costs and the recovery of the Tenaska regulatory asset even if the benchmark is exceeded. Due to fluctuations in forward market prices of natural 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, 2008 based on current forward market natural gas prices are as follows:

| (DOLLARS IN MILLIONS) | 2009 | 2010 | 2011 |
|---|---|---|---|
| Projected Tenaska costs * | $ 208.3 | $ 238.9 | $ 236.6 |
| Projected Tenaska benchmark costs | 189.9 | 197.4 | 205.6 |
| Over benchmark costs | $ 18.4 | $ 41.5 | $ 31.0 |
| | | | |
| Projected 50% disallowance based on Washington Commission methodology | $ 4.8 | $ 3.0 | $ 1.1 |

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

**Regulatory Matters.** On December 15, 2006, FERC began an audit of PSE's Open Access Transmission Tariff and Standards of Conduct for the period January 1, 2004 through December 31, 2006. The focus of the audit is PSE's operation of its electric transmission system and tariff and its energy trading function. On July 16, 2008, FERC issued its final audit report which discussed five areas of non-compliance with certain FERC requirements. PSE was ordered to take several remedial actions and develop a compliance plan, but incurred no penalties as a result of the audit. PSE is also required to make quarterly filings to FERC reporting on the status of its remedial activities until all corrective actions required in the audit report have been implemented.

On December 18, 2007, PSE received a data request from the Investigations Division of the Office of Enforcement at FERC seeking information about certain natural gas pipeline capacity release transactions PSE entered into in 2006 and 2005. PSE responded to the data requests on January 23, 2008 and met with FERC staff on January 31, 2008. At this meeting, PSE discussed with FERC staff additional transactions discovered in the course of responding to the data requests that potentially may be in violation of FERC regulations. PSE received additional data requests from FERC on February 20, 2008. In October 2008, PSE received preliminary notification from FERC staff that PSE had violated several FERC regulations and was subject to potential civil penalties and other remedies. FERC has not yet issued a formal investigation report and thus, PSE is not able to predict the ultimate outcome of this investigation, including the amount of any penalties, at this time.

On December 30, 2008, the Washington Commission approved an order authorizing the sale of Puget Energy and PSE to Puget Holdings subject to a Settlement Stipulation which included 78 conditions. Items included in the conditions that may affect the financial statements are dividend restrictions for Puget Energy and PSE. These items are discussed in Note 6. In addition, the conditions provided for rate credits of $10.0 million per year due to merger savings and a lower return by the investor consortium over a ten-year period beginning at the closing of the transaction.

Electric reliability standards adopted by FERC, NERC and/or the Western Electricity Coordinating Council (WECC) include periodic self-certifications of compliance, self-reports of violations after discovery of the violation, spot checks to review self-certifications and external audits that review compliance with designated standards. In accordance with the Compliance Monitoring Enforcement Program process, PSE self-reports violations when they are discovered. Such self-reports could result in settlement of issues without a penalty or issuances of penalties in the future.

### COLSTRIP MATTERS

In May 2003, approximately 50 plaintiffs initiated an action against the owners of Colstrip alleging that (1) seepage from two different wastewater pond areas caused groundwater contamination and threatened to contaminate domestic water wells and the Colstrip water supply pond, and (2) seepage from the Colstrip water supply pond caused structural damage to buildings and toxic mold. The defendants reached agreement on a global settlement with all plaintiffs on April 29, 2008 and PSE paid its share of the settlement in the amount of $10.7 million in July 2008. PSE had previously expensed the settlement in the first quarter 2008. PSE has also filed an accounting petition with the Washington Commission to recover such costs in the future.

On March 29, 2007, a second complaint related to pond seepage was filed on behalf of two ranch owners alleging damage due to the Colstrip Units 3 & 4 effluent holding pond. Discovery is on-going and no trial date has been set.

The federal Clean Air Mercury Rule, enacted by the Environmental Protection Agency (EPA) in May 2005, was vacated by the D.C. Circuit Court in February 2008. Final resolution of this matter is still pending. However the Montana Board of Environmental Review approved a Montana mercury control rule to limit mercury emissions from coal-fired plants on October 16, 2006 (with a limit of 0.9 lbs/TBtu for plants burning coal like that used at Colstrip) which remains in effect. In 2008 the Colstrip owners, based on testing performed in 2006, 2007 and 2008, ordered mercury control equipment intended to achieve the new limit. Installation of this equipment is planned for 2009, following which evaluation will be conducted of whether additional controls, if any, are necessary.

In February 2007, Colstrip was notified by EPA that Colstrip Units 1 & 2 were determined to be subject to EPA's Best Available Retrofit Technology (BART) requirements. PSE submitted a BART engineering analysis for Colstrip Units 1 & 2 in August 2007 and responded to an EPA request for additional analyses with an addendum in June 2008. PSE cannot yet determine the outcome.

The Minerals Management Service of the United States Department of Interior (MMS) issued a series of orders to Western Energy Company (WECO) to pay additional taxes and royalties concerning coal WECO sold to the owners of Colstrip 3 & 4 and similar orders have been issued in the administrative appellate process. The orders asserted that additional royalties are owed in connection with payments received by WECO from Colstrip 3 & 4 owners (including PSE) for the construction and operation of a conveyor system that runs several miles from the mine to Colstrip 3 & 4. The state of Montana also issued a demand to WECO consistent with the MMS position. In November and December 2008, WECO and the Colstrip 3 & 4 owners reached settlements of these issues with the state of Montana and with the MMS. The settlements will result in payments of agreed amounts with respect to the allegedly past due payments, and establish an ongoing payment process for keeping all future obligations current. PSE's outstanding payment for the past due amounts in total is $2.8 million, which has been fully reserved.

The MMS also issued an order to WECO concerning allegedly unpaid past due royalties for a "gross inequity" settlement that WECO, Montana Power Company and PSE entered into in 1997. In December 2008, WECO and the MMS reached a settlement in principle of this MMS claim. Under the 1997 settlement, PSE will reimburse WECO for such payments. The payment will likely be made in the first quarter of 2009, after documentation is complete, in the approximate amount of $1.9 million. This amount has been fully reserved.

A lawsuit was filed in February 2009 against the Colstrip operator related to a fatality that occurred at the plant in June 2008. PSE's level of exposure in this matter is currently unknown.

**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 or 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, 2007, the net receivable for such sales was approximately $21.1 million. PSE's ability to recover all or a portion of this amount is uncertain. At this time, management believes there is no reasonable basis under applicable financial accounting standards 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 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 remanded to FERC the question of whether to allow refunds. In March and April 2008, FERC issued orders establishing procedures for the *Lockyer* remand. The orders commence a seller-by-seller inquiry into the transaction reports filed by entities that sold power in California during 2000. The inquiry is to determine if the transaction reports as filed masked the gathering of more than 20.0% of the market during the period by that seller. The California parties sought rehearing on a variety of these issues. On October 6, 2008, FERC issued a decision on the rehearing request that reaffirmed its intent to impose seller-specific remedies rather than the market-wide remedy sought by the California parties. The rehearing decision also reconfirms FERC's method for determining market share, limits the scope of the proceeding and declines to defer the proceeding pending remand from the Ninth Circuit of the California Refund Proceeding and the Port of Seattle (Pacific Northwest Refund) case. PSE believes that it will not be found to have possessed 20.0% of any relevant market during any relevant time. The proceeding continues, including a settlement process before an Administrative Law Judge (ALJ). Settlement talks among various parties continue but PSE cannot predict the ultimate outcome of any negotiations or subsequent process before FERC or the ALJ.

*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. Rehearing by the Ninth Circuit on this matter was sought on November 16, 2007. The rehearing petition has not been acted upon. In addition, parties have been engaged in court-sponsored settlement discussions, and those discussions may result in some settlements. PSE is unable to predict either the outcome of the proceedings or the ultimate financial effect on 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. On August 24, 2007, the Ninth Circuit issued a decision concluding that FERC should have evaluated and considered evidence of market manipulation in California and its potential impact in the Pacific Northwest. It also decided that FERC should have considered purchases made by the California Energy Resources Scheduler and/or the California Department of Water Resources in the Pacific Northwest Proceeding. On December 17, 2007, PSE and Powerex separately filed requests for rehearing with the Ninth Circuit of this decision. Those requests remain pending. PSE intends to vigorously defend its position in this proceeding, but it is unable to predict the outcome of this matter.

**PROCEEDINGS RELATING TO THE BONNEVILLE POWER ADMINISTRATION**

Petitioners in several actions in the Ninth Circuit against BPA asserted that BPA acted contrary to law 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 REP. Petitioners in several actions in the Ninth Circuit against BPA also asserted that BPA acted contrary to law in adopting or implementing the rates upon which the benefits received or to be received from BPA during the October 1, 2001 through September 30, 2006 period were based. A number of parties 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.

On May 3, 2007, the Ninth Circuit issued an opinion in *Portland Gen. Elec. v. BPA*, Case No. 01-70003, in which proceeding the actions of BPA in entering into settlement agreements regarding the REP with PSE and with other investor-owned utilities were challenged. In this opinion, the Ninth Circuit granted petitions for review and held the settlement agreements entered into between BPA and the investor-owned utilities being challenged in that proceeding to be inconsistent with statute. On May 3, 2007, the Ninth Circuit also issued an opinion in *Golden Northwest Aluminum v. BPA*, Case No. 03-73426, in which proceeding the petitioners sought review of BPA's 2002-2006 power rates. In this opinion, the Ninth Circuit granted petitions for review and held that BPA unlawfully shifted onto its preference customers the costs of its settlements with the investor-owned utilities. On October 5, 2007, petitions for rehearing of these two opinions were denied. On February 1, 2008, PSE and other utilities filed in the Supreme Court of the United States a petition for a writ of certiorari to review the decisions of the Ninth Circuit, which petition was denied in June 2008.

In May 2007, following the Ninth Circuit's issuance of these two opinions, BPA suspended payments to PSE under the amended settlement agreement (and the May 2004 agreement). On October 11, 2007, the Ninth Circuit remanded the May 2004 agreement to BPA in light of the *Portland Gen. Elec. v. BPA* opinion and dismissed the remaining three pending cases regarding settlement agreements.

In March 2008, BPA and PSE signed an agreement pursuant to which BPA made a payment to PSE related to the REP benefits for the fiscal year ended September 30, 2008, which payment is subject to true-up depending upon the amount of any REP benefits ultimately determined to be payable to PSE. In March and April 2008, Clatskanie People's Utility District filed petitions in the Ninth Circuit for review of BPA actions in connection with offering or entering into such agreement with PSE and similar agreements with other investor-owned utilities. Clatskanie People's Utility District asserts that BPA's actions in entering into and executing the 2008 REP agreements were contrary to law or without authority and that such agreements are null and void and result in overpayments of REP benefits to PSE and other regional investor-owned utilities.

In September 2008, BPA issued its record of decision in its reopened WP-07 rate proceeding to respond to the various Ninth Circuit opinions. In this record of decision, BPA adjusted its fiscal year 2009 rates, determined the amounts of REP benefits it considered to have been improperly paid after fiscal year 2001 to PSE and the other regional investor-owned utilities, and determined that such amounts are to be recovered through reductions in REP benefit payments to be made over a number of years. The amount determined by BPA to be recovered (with interest) through reductions commencing October 2007 in REP payments for PSE's residential and small farm customers was approximately $207.2 million plus interest on unrecovered amounts to the extent that PSE receives any REP benefits for its customers in the future. However, these BPA determinations are subject to subsequent administrative and judicial review, which may alter or reverse such determinations. PSE and others, including a number of preference agency and investor-owned utility customers of BPA, in December 2008 filed petitions for review in the Ninth Circuit of various of these BPA determinations. PSE is also reviewing its options in determining if it will contest the amounts withheld as improper payments made after 2001.

In September 2008, BPA and PSE signed a short-term Residential Purchase and Sale Agreement (RPSA) under which BPA is to pay REP benefits to PSE for fiscal years ending September 30, 2009–2011. In December 2008, BPA and PSE signed another, long-term RPSA under which BPA is to pay REP benefits to PSE for the period October 2011 through September 2028. PSE and other customers of BPA in December 2008 filed petitions for review in the Ninth Circuit of the short-term and long-term RPSAs signed by PSE (and similar RPSAs signed by other investor-owned utility customers of BPA) and BPA's record of decision regarding such RPSAs. Generally, REP benefit payments under a RPSA are based on the amount, if any, by which a utility's average system cost (ASC) exceeds BPA's Preference Rate (PF) Exchange rate for such utility. The ASC for a utility is determined using an ASC methodology adopted by BPA. The ASC methodology adopted by BPA and the ASC determinations, REP overpayment determinations, and the PF Exchange rate determinations by

BPA are all subject to FERC review or judicial review or both and are subject to adjustment, which may affect the amount of REP benefits paid or to be paid by BPA to PSE. As discussed above, BPA has determined to reduce such payments based on its determination of REP benefit overpayments after fiscal year 2001.

It is not clear what impact, if any, such development or review of such BPA rates, review of such ASC, ASC Methodology, and BPA determination of REP overpayments, review of such agreements, and the above described Ninth Circuit litigation may ultimately have on PSE.

**PROCEEDING RELATING TO THE MERGER**

On October 26, 2007 and November 2, 2007, two separate lawsuits were filed against the Company and all of the members of the Company's Board of Directors in Superior Court in King County, Washington. The lawsuits, respectively, are entitled, *Tansey v. Puget Energy, Inc., et al.*, Case No. 07-2-34315-6 SEA and *Alaska Ironworkers Pension Trust v. Puget Energy, Inc., et al.,* Case No. 07-2-35346-1 SEA. The lawsuits are both denominated as class actions purportedly on behalf of Puget Energy's shareholders and assert substantially similar allegations and causes of action relating to the proposed merger. (See Note 25 for more information regarding the transaction.) The complaints allege that the Company's directors breached their fiduciary duties in connection with entering into the merger agreement and seek virtually identical relief, including an order enjoining the consummation of the merger. Pursuant to a court order dated November 26, 2007, the two cases were consolidated for all purposes and entitled *In re Puget Energy, Inc. Shareholder Litigation*, Case No. 07-2-34315-6 SEA.

On February 6, 2008, the Company entered into a memorandum of understanding providing for the settlement of the consolidated shareholder lawsuit, subject to customary conditions including completion of appropriate settlement documentation, confirmatory discovery and court approval. Pursuant to the memorandum of understanding, the Company agreed to include certain additional disclosures in its proxy statement relating to the merger. The Company does not admit, however, that its prior disclosures were in any way materially misleading or inadequate. In addition, the Company and the other defendants in the consolidated lawsuit deny the plaintiffs' allegations of wrongdoing and violation of law in connection with entering into the merger agreement. The settlement, if completed and approved by the court, will result in dismissal with prejudice and release of all claims of the plaintiffs and settlement class of the Company's shareholders that were or could have been brought on behalf of the plaintiffs and the settlement class. In connection with such settlement, the plaintiffs intend to seek a court-approved award of attorneys' fees and expenses in an amount up to $290,000, which the Company has agreed to pay. As of December 31, 2008, the Company has a loss reserve of $290,000. The settlement approval process has begun and will take several months to complete.

**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 natural 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 GAAP, 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 Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71). 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, 2008 in the amount of $1.0 billion and $228.1 million, respectively, and regulatory assets and liabilities of $793.0 million and $288.3 million, respectively, at December 31, 2007. 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.** PSE 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" (SFAS No. 133), as amended by SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities-an amendment of FASB Statement No. 133" (SFAS No. 138) and SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS No. 149). Accounting for derivatives continues to evolve through guidance issued by the Financial Accounting Standards Board (FASB). To manage its electric and natural gas portfolios, PSE enters into contracts to purchase or sell electricity and natural 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 (NPNS) exception. If the exception applies, those contracts are not marked-to-market and are not reflected in the financial statements until delivery occurs. The majority of the Company's physical contracts qualify for the NPNS exception to derivative accounting rules. Generally, NPNS applies if the Company deems the counterparty creditworthy, if the counterparty owns or controls energy resources within the western region to allow for physical delivery of the energy and if the transaction is within the Company's forecasted load requirements.

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 of the effective portion of the hedge 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 an independent external pricing service. The Company regularly confirms the validity of pricing service quoted prices (e.g. Level 2 in the fair value hierarchy) used to value commodity contracts to the actual prices of commodity contracts entered into during the most recent quarter. 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. The Company is focused on commodity price exposure and risks associated with volumetric variability in the natural gas and electric portfolios. It is not engaged in the business of assuming risk for the purpose of speculative trading. The Company hedges open natural 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 250 simulations of how the Company's natural gas and power portfolios will perform under various weather, hydro and unit performance conditions. The Company has not made any material changes during the reporting period to those techniques or models.

**Fair Value.** As defined in SFAS No. 157, "Fair Value Measurements" (SFAS No. 157), fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). However, as permitted under SFAS No. 157, the Company utilizes a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient for valuing the majority of its assets and liabilities measured and reported at fair value. The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The Company primarily applies the market approach for recurring fair value measurements and endeavors to utilize the best available information. Accordingly, the Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

As a result of the recent credit crisis, the Financial Accounting Standards Board (FASB) recently issued Staff Position (FSP) FAS No. 157-3, “Determining the Fair Value of a Financial Asset in a Market That is Not Active” (FSP No. 157-3). FSP No. 157-3 clarifies the application of SFAS No. 157 in a market that is not active. As of December 31, 2008, the Company considers the markets for its electric and natural gas Level 2 derivative instruments to be actively traded. Management’s assessment is based on the trading activity volume in real-time and forward electric and natural gas markets. The Company regularly confirms the validity of pricing service quoted prices (e.g. Level 2 in the fair value hierarchy) used to value commodity contracts to the actual prices of commodity contracts entered into during the most recent quarter. The Company has concluded that FSP No. 157-3 did not have a significant impact to existing processes.

**Pension and Other Postretirement Benefits.** PSE has a qualified defined benefit pension plan covering substantially all employees of PSE. Qualified pension income of $0.4 million was recorded in 2008. Qualified pension expense of $2.8 million was recorded in 2007. Qualified pension expense of $1.0 million was recorded for 2006. Of these amounts, approximately 60.0%, 58.6% and 56.6% were included in utility operations and maintenance expense in 2008, 2007 and 2006, respectively and the remaining amounts were capitalized. It is expected that PSE will recognize qualified pension expense of $2.0 million in 2009.

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 PSE 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 2008, PSE made a cash contribution of $24.9 million to the qualified defined benefit plan. Management is closely monitoring the funding status of its qualified pension plan given the recent volatility of the financial markets and may make a contribution in 2009 depending on pension plan requirements.

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 | | |
|---|---|---|---|---|
| (Dollars in Thousands) | | Pension Benefits | SERP | Other Benefits |
| Increase in discount rate | 50 basis points | $ (22,459) | $ (1,680) | $ (701) |
| Decrease in discount rate | 50 basis points | 23,770 | 1,814 | 756 |
| Increase in return on plan assets | 50 basis points | * | * | * |
| Decrease in return on plan assets | 50 basis points | * | * | * |

| | Change in Assumption | Impact on 2008 Pension Expense (Increase) Decrease | | |
|---|---|---|---|---|
| (Dollars in Thousands) | | Pension Benefits | SERP | Other Benefits |
| Increase in discount rate | 50 basis points | $ (1,119) | $ (146) | $ (57) |
| Decrease in discount rate | 50 basis points | 2,350 | 154 | 61 |
| Increase in return on plan assets | 50 basis points | (2,519) | * | (69) |
| Decrease in return on plan assets | 50 basis points | 2,519 | * | 70 |

* *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, 2008, such remaining receivables were approximately $21.1 million.

Based on the calculation of existing FERC orders issued to date, PSE has determined that the receivable balance at December 31, 2008 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.

**NEW ACCOUNTING PRONOUNCEMENTS**

On March 19, 2008, FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities – An Amendment of FASB Statement No. 133" (SFAS No. 161). SFAS No. 161 is effective for the fiscal years and interim years beginning after November 15, 2008, which will be the quarter ending March 31, 2009 for the Company. SFAS No. 161 requires companies with derivative instruments to disclose information that should enable financial statement users to understand how and why a company uses derivative instruments, how derivative instruments and related hedged items are accounted for under SFAS No. 133 and how derivative instruments and related hedged items affect a company's financial position, financial performance and cash flows. SFAS No. 161 requirements will impact the following derivative and hedging disclosures: objectives and strategies, balance sheet, financial performance, contingent features and counterparty credit risk. The Company has adopted the disclosure requirements effective with the year ending December 31, 2008.

In May 2008, FASB issued SFAS No. 162, "The Hierarchy of Generally Accepted Accounting Principles" (SFAS No. 162), which identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements of nongovernmental entities that are presented in conformity with GAAP. The FASB is responsible for identifying the sources of accounting principles and providing entities with a framework for selecting the principles used in the preparation of financial statements. The Company has reviewed the statement and has assessed that there will be no significant impact to the financial statements.

On December 30, 2008, FASB issued FSP FAS No. 132(R) -1, "Employers' Disclosures about Postretirement Benefit Plan Assets" (FSP No. 132(R)-1). FSP No. 132(R)-1 directs companies to provide additional disclosures about plan assets of a defined benefit pension or other postretirement plan. The objectives of the disclosures are as follows: (1) how investment allocation decisions are made, including the factors that are pertinent to an understanding of investment policies and strategies, (2) major categories of plan assets, (3) inputs and valuation techniques used to measure the fair value of plan assets, (4) effect of fair value measurements using significant unobservable inputs (Level 3) on changes in plan assets for the period, and (5) significant concentrations of risk within plan assets. FSP No. 132(R)-1 is effective for the fiscal year December 15, 2009, which will be effective for the Company for the fiscal year end December 31, 2009. The Company is currently assessing the impact of FSP No. 132(R)-1 on its disclosures.

In December 2008, FASB issued Interpretation 46R-8, "Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interests in Variable Interest Entities" (FIN 46R-8), which requires new expanded disclosures in the financial statements for year ended December 31, 2008 for variable interest entities (VIEs). FIN 46R-8 amends FIN 46R to require certain disclosures by a public enterprise that is (a) a sponsor that has a variable interest in a VIE (irrespective of the significance of the variable interest) and (b) an enterprise that holds a significant variable interest in a qualifying special purpose entity (SPE) but was not the transferor (nontransferor enterprise) of financial assets to the qualifying SPE. The disclosures required by FIN 46R-8 are intended to provide users of the financial statements with greater transparency about a transferor's continuing involvement with transferred financial assets and an enterprise's involvement with VIEs.

In December 2007, the FASB issued SFAS No. 141(R), "Business Combinations" (SFAS No. 141(R)). SFAS No. 141(R) replaces FASB Statement No. 141, "Business Combinations," and addresses the accounting for all transactions or other events in which an entity obtains control of one or more businesses. The objective of SFAS No. 141(R) is to improve the relevance, representational faithfulness and comparability of the information that a reporting entity provides in its financial reports about a business combination and its effects. To accomplish that, SFAS No. 141(R) establishes principles and requirements for how the acquirer: (1) recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree; (2) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase; and (3) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS No. 141(R) shall be applied prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. The Company will apply this standard for any business combinations beginning on January 1, 2009.

On September 15, 2006, FASB issued SFAS No. 157, which clarifies how companies should use fair value measurements in accordance with GAAP for recognition and disclosure purposes. SFAS No. 157 establishes a common definition of fair value and a framework for measuring fair value under GAAP, along with expanding disclosures about fair value to eliminate differences in current practice that exist in measuring fair value under the existing accounting standards. The definition of fair value in SFAS No. 157 retains the notion of exchange price; however, it focuses on the price that would be received to sell the asset or paid to transfer a liability (i.e. an exit price), rather than the price that would be paid to acquire the asset or received to assume the liability (i.e. an entrance price). Under SFAS No. 157, a fair value measure should reflect all of the assumptions that market participants would use in pricing the asset or liability, including assumptions about the risk inherent in a particular valuation technique, the effect of a restriction on the sale or use of an asset and the risk of nonperformance. To increase consistency and comparability in fair value measures, SFAS No. 157 establishes a three-level fair value hierarchy to prioritize the inputs used in valuation techniques between observable inputs that reflect quoted market prices in active markets, inputs other than quoted prices with observable market data and unobservable data (e.g. a company's own data).

SFAS No. 157 is effective for fiscal years beginning after November 15, 2007, which was the year beginning January 1, 2008, for the Company. On February 28, 2008, the FASB issued a final FSP that partially deferred the effective date of SFAS No. 157 for one year for non-financial assets and non-financial liabilities that are recognized or disclosed at fair value, except for those that are recognized or disclosed at fair value on an annual or more frequent basis. The Company adopted SFAS No. 157 on January 1, 2008, prospectively, as required by the Statement for financial and nonfinancial measured on a recurring basis, with certain exceptions, including the initial impact of changes in fair value measurements of existing derivative financial instruments measured initially using the transaction price under Emerging Issues Task Force of the Financial Accounting Standards Board (EITF) No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposed and Contracts Involved in Energy Trading and Risk Management Activities" (EITF No. 02-3).

SFAS No. 157 nullified a portion of EITF No. 02-3. Under EITF No. 02-3, the transaction price presumption prohibited recognition of a trading profit at inception of a derivative unless the positive fair value of that derivative was substantially based on quoted prices or a valuation process incorporating observable inputs. For transactions that did not meet this criterion at inception, trading profits that had been deferred were recognized in the period that inputs to value the derivative became observable or when the contract performed.

On January 1, 2008, the difference between the carrying amounts and the fair values of those instruments originally recorded under guidance in EITF No. 02-3 was recognized as a cumulative-effect adjustment to the opening balance of retained earnings of $9.0 million before tax as a result of recording a deferred loss on net derivative assets and liabilities.

As a result of the recent credit crisis, on October 10, 2008, the FASB issued FSP No. 157-3. FSP No. 157-3 clarifies the application of SFAS No. 157 in a market that is not active. FSP No. 157-3 addresses how management should consider measuring fair value when relevant observable data does not exist. FSP No. 157-3 also provides guidance on how observable market information in a market that is not active should be considered when measuring fair value, as well as how the use of market quotes should be considered when assessing the relevance of observable and unobservable data available to measure fair value. FSP No. 157-3 was effective upon issuance, including prior periods for which financial statement have not been issued. Revisions resulting from a change in the valuation technique or its application shall be accounted for as a change in accounting estimate (FASB Statement No. 154, "Accounting Changes and Error Corrections," (SFAS No. 154) paragraph 19). The disclosure provisions of SFAS No. 154 for a change in accounting estimate are not required for revisions resulting from a change in valuation technique or its application. The Company has reviewed the statement and has assessed that there will be no significant impact to the financial statements.

# ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

### ENERGY PORTFOLIO MANAGEMENT

The Company maintains energy risk policies and procedures to manage commodity and volatility risks and the related effects on credit, tax, accounting, financing and liquidity. The Company's Energy Management Committee establishes the

Company's risk management policies and procedures, and monitors compliance. The Energy Management Committee is comprised of certain Company officers and is overseen by the Board of Directors.

The Company is focused on commodity price exposure and risks associated with volumetric variability in the gas and electric portfolios and the related effects noted above. 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 250 simulations of how the Company's gas and power portfolios will perform under various weather, hydro and unit performance conditions. The objectives of the hedging strategy are to:

- ensure physical energy supplies are available to reliably and cost-effectively serve retail load;
- manage the energy portfolio prudently to serve retail load at overall least cost and limit undesired impacts on PSE's customers and shareholders;
- reduce power costs by extracting the value of the Company's assets; and
- meet the credit, liquidity, financing, tax and accounting requirements of the Company.

The following table presents electric derivatives that are designated as cash flow hedges or contracts that do not meet the Normal Purchase Normal Sale (NPNS) exception at December 31, 2008 and December 31, 2007:

| | Electric Derivatives | |
|---|---|---|
| (Dollars in Millions) | December 31, 2008 | December 31, 2007 |
| Current asset | $ 0.4 | $ 11.1 |
| Long-term asset | 0.5 | 6.6 |
| Total assets | $ 0.9 | $ 17.7 |
| | | |
| Current liability | $ 90.6 | $ 9.8 |
| Long-term liability | 96.1 | -- |
| Total liabilities | $ 186.7 | $ 9.8 |

If it is determined that it is uneconomical to operate the Company's controlled electric generating facilities in the future period, the fuel supply cash flow hedge relationship is terminated and the hedge is de-designated which results in the unrealized gains and losses associated with the contracts being recorded in the income statement. As these contracts are settled, the costs are recognized as energy costs and are included as part of the PCA mechanism.

At December 31, 2007, the Company had an unrealized day one loss deferral of $9.0 million related to a three-year locational power exchange contract which had a valuation based on unobservable prices and therefore the day one loss was deferred under EITF No. 02-3. The contract has economic benefit to the Company over its terms. The locational exchange will help ease electric transmission congestion across the Cascade Mountains during the winter months as the Company will take delivery of energy at a location that interconnects with the Company's transmission system in western Washington. At the same time, the Company will make available the quantities of power at the Mid-Columbia trading hub location. The day one loss deferral was transferred to retained earnings on January 1, 2008 as required by SFAS No. 157 and any future day one loss on contracts will be recorded in the income statement beginning January 1, 2008 in accordance with the statement.

The following table presents the impact of changes in the market value of derivative instruments not meeting NPNS or cash flow hedge criteria to the Company's earnings during the twelve months ending December 31, 2008 and December 31, 2007:

| (Dollars in millions) | December 31, 2008 | December 31, 2007 | Change |
|---|---|---|---|
| Increase (decrease) in earnings | $ (7.5) | $ 2.7 | $ (10.2) |

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 under SFAS No. 133 of $7.5 million for 2008 compared to an increase in earnings of $2.7 million for 2007. The decrease in earnings in 2008 primarily relates to a $6.1 million unrealized loss associated with the ineffective portion of cash flow hedges for two long-term power supply agreements.

The amount of unrealized gain (loss), net of tax, related to the Company's energy-related cash flow hedges under SFAS No. 133 consisted of the following at December 31, 2008 and December 31, 2007:

| (DOLLARS IN MILLIONS, NET OF TAX) | DECEMBER 31, 2008 | DECEMBER 31, 2007 |
|---|---|---|
| Other comprehensive income – unrealized gain/(loss) | $ (111.7) | $ 3.4 |

The following table presents the derivative hedges of natural gas contracts to serve natural gas customers at December 31, 2008 and December 31, 2007:

| | GAS DERIVATIVES | |
|---|---|---|
| (DOLLARS IN MILLIONS) | DECEMBER 31, 2008 | DECEMBER 31, 2007 |
| Current asset | $ 15.2 | $ 6.0 |
| Long-term asset | 6.2 | 5.3 |
| Total assets | $ 21.4 | $ 11.3 |
| | | |
| Current liability | $ 146.3 | $ 17.3 |
| Long-term liability | 62.3 | -- |
| Total liabilities | $ 208.6 | $ 17.3 |

At December 31, 2008, the Company had total assets of $21.4 million and total liabilities of $208.6 million related to 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.

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 $40.4 million after-tax, with a corresponding after-tax impact in comprehensive income and earnings (due to ineffectiveness) of $39.4 million and $1.0 million, respectively, after-tax, and would increase the fair value of those contracts marked-to-market in earnings by $0.3 million after-tax.

The change in fair value of outstanding energy derivative instruments from December 31, 2007 through December 31, 2008 is summarized in the table below:

| ENERGY DERIVATIVE CONTRACTS GAIN (LOSS) (DOLLARS IN MILLIONS) | AMOUNTS |
|---|---|
| Fair value of contracts outstanding at December 31, 2007 | $ 2.0 |
| Contracts realized or otherwise settled during 2008 | 4.0 |
| SFAS No. 157 transition adjustment[1] | (9.0) |
| Change in fair values of derivatives | (369.9) |
| Fair value of contracts outstanding at December 31, 2008 | $ (372.9) |

1 *SFAS No. 157 transition adjustment related to day one loss deferral of a three-year Locational Power Exchange contract, valued under (EITF No. 02-03 guidance. See Note 17, Accounting for Derivative Instruments and Hedging Activities.*

The change in fair value of other financial items and money market accounts from December 31, 2007 through December 31, 2008 is summarized in the table below:

| (DOLLARS IN MILLIONS) | AMOUNTS |
|---|---|
| Fair value of other financial items and money market accounts at December 31, 2007 | $ 6.0 |
| Change in fair value of other financial items[1] | 7.1 |
| Change in fair value of money market accounts | 13.0 |
| Fair value of other financial items and money market accounts at December 31, 2008 | $ 26.1 |

1 *Other financial items valuation is described in Note 3. Discontinued Operations and Corporate Guarantees (Puget Energy Only).*

The fair value of outstanding derivative instruments at December 31, 2008, based on price source and the period during which the instrument will mature are summarized below:

| | FAIR VALUE OF CONTRACT WITH SETTLEMENT DURING YEAR | | | | |
|---|---|---|---|---|---|
| SOURCE OF FAIR VALUE (DOLLARS IN MILLIONS) | 2009 | 2010-2011 | 2012-2013 | 2014 & THEREAFTER | TOTAL FAIR VALUE |
| Prices actively quoted[1] | $ 26.1 | $ -- | $ -- | $ -- | $ 26.1 |
| Prices provided by external sources[2] | (195.0) | (44.3) | -- | -- | (239.3) |
| Prices based on internal models and valuation methods[3] | (26.3) | (86.8) | (18.4) | (2.1) | (133.6) |
| Total fair value | $ (195.2) | $ (131.1) | $ (18.4) | $ (2.1) | $ (346.8) |

1 *Quoted prices available in active markets for equity securities that are also classified as cash equivalents (i.e. money market accounts).*

2 *Prices provided by external pricing service, which utilizes broker quotes and pricing models. Pricing inputs are based on observable market data.*

3 *Pricing derived from inputs with internally developed methodologies. Pricing inputs are generally less observable than objective sources.*

**CONTINGENT FEATURES AND COUNTERPARTY CREDIT RISK**

The Company is exposed to credit risk primarily through buying and selling electricity and natural 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 and exposure monitoring and exposure mitigation.

Where deemed appropriate, the Company may request collateral or other security from its counterparties to mitigate the potential credit default losses. Criterion employed in this decision includes, among other things, the perceived creditworthiness of the counterparty and the expected credit exposure. As of December 31, 2008, the Company held approximately $2.3 million worth of standby letters of credit in support of various electricity and renewable energy credit transactions.

It is possible that volatility in energy commodity prices could cause the Company to have material 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, 2008, approximately 99.9% of the counterparties with transaction amounts outstanding in the Company's energy portfolio are rated at least investment grade by the major rating agencies and 0.1% 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.

The Company has entered into commodity master arrangements with its counterparties to mitigate credit exposure to those counterparties. The Company generally enters into the following master arrangements: (1) Western Systems Power Pool agreements (WSPP) - standardized power sales contract in the electric industry; (2) International Swaps and Derivatives Association agreements (ISDA) - standardized financial gas and electric contracts; and (3) North American Energy Standards Board agreements (NAESB) - standardized physical gas contracts. The Company believes that entering into such agreements reduces the risk of default by allowing a counterparty the ability to make only one net payment.

The Company monitors counterparties that are experiencing financial problems, have significant swings in credit default swap rates, have credit rating changes by external rating agencies, or have changes in ownership. Counterparty credit risk impacts the Company's decisions on derivative accounting treatment. A counterparty may have a deterioration of credit below investment grade, potentially indicating that it is no longer probable that it will fulfill its obligations under a contract (e.g., make a physical delivery upon the contract's maturity). SFAS No. 133 specifies the requirements for derivative contracts to qualify for the NPNS scope exception. When performance is no longer probable, based on the deterioration of a counterparty's credit, the Company records the fair value of the contract on the balance sheet, with the corresponding amount recorded in the income statement.

Cash flow hedge derivative treatment is also impacted by a counterparty's deterioration of credit under SFAS No. 133 guidelines. If a forecasted transaction associated with a cash flow hedge is no longer probable of occurring, based on deterioration of credit, the Company would discontinue hedge accounting, record in earnings subsequent changes in the derivative's fair value and freeze amounts previously accounted for in Accumulated Other Comprehensive Income. If the transaction is remote of occurring, any amounts previously accounted for in Accumulated Other Comprehensive Income would be reclassified into earnings.

Should a counterparty file for bankruptcy, which could be considered a default under master arrangements, the Company may terminate related contracts. Derivative accounting entries previously recorded would be reversed in financial statements. The Company would compute any termination receivable or payables, based on the terms of existing master arrangements.

The Company computes credit reserves at a master agreement level (i.e. WSPP, ISDA or NAESB) by counterparty. The Company considers external credit ratings and market factors, such as credit default swaps and bond spreads in determination of reserves. The Company recognizes that external ratings may not always reflect how a market participant perceives a counterparty's risk of default. The Company uses both default factors published by Standard & Poor's (S&P) and factors derived through analysis of market risk, which reflect the application of an industry standard recovery rate. The Company selects a default factor by counterparty at an aggregate master agreement level based on a weighted average default tenor for that counterparty's deals. The default tenor is used by weighting fair values and contract tenors for all deals for each counterparty and coming up with an average value. The default factor used is dependent upon whether the counterparty is in a net asset or a net liability position after applying the master agreement levels.

The Company applies the counterparty's default factor to compute credit reserves for counterparties that are in a net asset position. Moreover, the Company applies its own default factor based on the S&P credit rating to compute credit reserves for counterparties in a net liability position. The Company's S&P rating at December 31, 2008 was BBB- and was increased to BBB on January 16, 2009. Credit reserves are booked as contra accounts to unrealized gain/(loss) positions. As of December 31, 2008, the Company was in a net liability position with the majority of counterparties, so the default factors of counterparties did not have a significant impact on reserves for the year.

### 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, prior to the merger, 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 as of December 31, 2008 or 2007; however from time to time the Company may enter into treasury lock or forward starting swap contracts to hedge interest rate exposure related to an anticipated debt issuance. In conjunction with variable rate loans made through credit facilities at Puget Energy, at the close of the merger on February 6, 2009, financial hedges were entered into covering the full amount of the borrowings to swap the variable interest rate to a fixed rate for the five-year term of these facilities.

The carrying amounts and the fair values of the Company's debt instruments were:

| (DOLLARS IN MILLIONS) | DECEMBER 31, 2008 CARRYING AMOUNT | DECEMBER 31, 2008 FAIR VALUE | DECEMBER 31, 2007 CARRYING AMOUNT | DECEMBER 31, 2007 FAIR VALUE |
|---|---|---|---|---|
| Financial liabilities: | | | | |
| Short-term debt | $ 964.7 | $ 964.7 | $ 260.5 | $ 260.5 |
| Short-term debt owed by PSE to Puget Energy[1] | 26.1 | 26.1 | 15.8 | 15.8 |
| Long-term debt – fixed-rate[2] | 2,678.9 | 2,109.0 | 2,858.4 | 2,623.2 |

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 2008 and 2007.*

The ending balance in other comprehensive income related to the forward starting swaps and previously settled treasury lock contracts at December 31, 2008 is a net loss of $7.9 million after tax and accumulated amortization. This compares to a loss of $8.2 million in other comprehensive income after tax and accumulated amortization at December 31, 2007. 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 President and Chief Executive Officer, the Board members are independent of management.
- All members of our key Board committees – the Audit Committee, the Compensation and Leadership Development Committee and the Governance and Public Affairs Committee – are independent of management.
- The non-management 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/ Eric M. Markell | /s/ James W. Eldredge |
|---|---|---|
| Stephen P. Reynolds | Eric M. Markell | James W. Eldredge |
| *President and Chief Executive Officer* | *Executive Vice President* | *Vice President, Controller* |
| | *and Chief Financial Officer* | *and Chief Accounting Officer* |

# REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 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. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedules, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedules, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Notes 18, 13, 14 and 16 to the consolidated financial statements, the Company changed the manner in which it accounts for fair value measurements in 2008, the manner in which it accounts for uncertain tax positions in 2007, the manner in which it accounts for defined pension and other postretirement benefit plans in 2006 and the manner in which it accounts for share-based compensation in 2006.

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 3, 2009

# REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 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. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Notes 18, 13, 14 and 16 to the consolidated financial statements, the Company changed the manner in which it accounts for fair value measurements in 2008, the manner in which it accounts for uncertain tax positions in 2007 and the manner in which it accounts for defined pension and other postretirement benefit plans in 2006 and the manner in which it accounts for share-based compensation in 2006.

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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 3, 2009

*Puget Energy Consolidated Statements of*

# INCOME

(DOLLARS IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)

| FOR YEARS ENDED DECEMBER 31 | 2008 | 2007 | 2006 |
|---|---|---|---|
| Operating revenues: | | | |
| Electric | $ 2,129,463 | $ 1,997,829 | $ 1,777,745 |
| Gas | 1,216,868 | 1,208,029 | 1,120,118 |
| Other | 11,442 | 14,289 | 9,200 |
| Total operating revenues | 3,357,773 | 3,220,147 | 2,907,063 |
| Operating expenses: | | | |
| Energy costs: | | | |
| Purchased electricity | 903,317 | 895,592 | 917,801 |
| Electric generation fuel | 212,333 | 143,406 | 97,320 |
| Residential exchange | (40,664) | (52,439) | (163,622) |
| Purchased gas | 737,851 | 762,112 | 723,232 |
| Net unrealized (gain) loss on derivative instruments | 7,538 | (2,687) | 71 |
| Utility operations and maintenance | 461,632 | 403,681 | 354,590 |
| Other operations and maintenance | 12,785 | 13,636 | 6,362 |
| Merger related costs | 9,252 | 8,143 | -- |
| Depreciation and amortization | 312,128 | 279,222 | 262,341 |
| Conservation amortization | 61,650 | 39,955 | 32,320 |
| Taxes other than income taxes | 297,203 | 288,492 | 255,797 |
| Total operating expenses | 2,975,025 | 2,779,113 | 2,486,212 |
| Operating income | 382,748 | 441,034 | 420,851 |
| Other income (deductions): | | | |
| Other income | 33,274 | 28,942 | 28,592 |
| Charitable contributions | -- | -- | (15,000) |
| Other expense | (7,215) | (7,509) | (6,594) |
| Interest charges: | | | |
| AFUDC | 8,610 | 12,614 | 15,874 |
| Interest expense | (202,582) | (217,823) | (184,012) |
| Income from continuing operations before income taxes | 214,835 | 257,258 | 259,711 |
| Income tax expense | 59,906 | 72,582 | 92,487 |
| Income from continuing operations | 154,929 | 184,676 | 167,224 |
| Income (loss) from discontinued segment (net of tax) | -- | (212) | 51,903 |
| Net income before cumulative effect of accounting change | 154,929 | 184,464 | 219,127 |
| Cumulative effect of implementation of accounting change (net of tax) | -- | -- | 89 |
| Net income | $ 154,929 | $ 184,464 | $ 219,216 |
| Common shares outstanding weighted-average (in thousands) | 129,437 | 117,673 | 115,999 |
| Diluted shares outstanding weighted-average (in thousands) | 130,094 | 118,344 | 116,457 |
| Basic earnings per common share before cumulative effect from accounting change | $ 1.20 | $ 1.57 | $ 1.44 |
| Basic earnings per common share from discontinued operations | -- | -- | 0.45 |
| Basic earnings per common share | $ 1.20 | $ 1.57 | $ 1.89 |
| Diluted earnings per common share before cumulative effect from accounting change | $ 1.19 | $ 1.56 | $ 1.44 |
| Diluted earnings per common share from discontinued operations | -- | -- | 0.44 |
| Diluted earnings per common share | $ 1.19 | $ 1.56 | $ 1.88 |

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

*Puget Energy Consolidated Balance Sheets*

## ASSETS

(DOLLARS IN THOUSANDS)

| AT DECEMBER 31 | 2008 | 2007 |
|---|---|---|
| Utility plant: | | |
| Electric plant | $ 6,596,359 | $ 5,914,127 |
| Gas plant | 2,500,236 | 2,313,477 |
| Common plant | 550,368 | 506,211 |
| Less: Accumulated depreciation and amortization | (3,358,816) | (3,091,176) |
| Net utility plant | 6,288,147 | 5,642,639 |
| Other property and investments: | | |
| Investment in Bonneville Exchange Power contract | 29,976 | 33,503 |
| Other property and investments | 118,039 | 114,083 |
| Total other property and investments | 148,015 | 147,586 |
| Current assets: | | |
| Cash | 38,526 | 40,797 |
| Restricted cash | 18,889 | 4,793 |
| Accounts receivable, net of allowance for doubtful accounts | 203,563 | 218,781 |
| Secured pledged accounts receivable | 158,000 | 152,000 |
| Unbilled revenues | 248,649 | 210,025 |
| Materials and supplies, at average cost | 62,024 | 62,114 |
| Fuel and gas inventory, at average cost | 120,205 | 99,772 |
| Unrealized gain on derivative instruments | 15,618 | 17,130 |
| Prepaid income tax | 19,121 | 44,303 |
| Prepaid expense and other | 14,964 | 11,910 |
| Deferred income taxes | 9,439 | 4,011 |
| Total current assets | 908,998 | 865,636 |
| Other long-term assets: | | |
| Regulatory asset for deferred income taxes | 95,417 | 104,928 |
| Regulatory asset for PURPA buyout costs | 110,838 | 140,520 |
| Power cost adjustment mechanism | 3,126 | 3,114 |
| Other regulatory assets | 766,732 | 510,998 |
| Unrealized gain on derivative instruments | 6,712 | 11,845 |
| Other | 40,421 | 171,470 |
| Total other long-term assets | 1,023,246 | 942,875 |
| Total assets | $ 8,368,406 | $ 7,598,736 |

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

# CAPITALIZATION AND LIABILITIES

(DOLLARS IN THOUSANDS)

| AT DECEMBER 31 | 2008 | 2007 |
|---|---|---|
| Capitalization: | | |
| *(See Consolidated Statements of Capitalization )* | | |
| Common equity | $ 2,273,201 | $ 2,521,954 |
| Total shareholders' equity | 2,273,201 | 2,521,954 |
| Redeemable securities and long-term debt: | | |
| Preferred stock subject to mandatory redemption | 1,889 | 1,889 |
| Junior subordinated notes | 250,000 | 250,000 |
| Long-term debt | 2,270,860 | 2,428,860 |
| Total redeemable securities and long-term debt | 2,522,749 | 2,680,749 |
| Total capitalization | 4,795,950 | 5,202,703 |
| Current liabilities: | | |
| Accounts payable | 342,254 | 310,398 |
| Short-term debt | 964,700 | 260,486 |
| Current maturities of long-term debt | 158,000 | 179,500 |
| Accrued expenses: | | |
| Purchased gas liability | 8,892 | 77,864 |
| Taxes | 85,068 | 84,756 |
| Salaries and wages | 35,280 | 28,516 |
| Interest | 36,074 | 45,133 |
| Unrealized loss on derivative instruments | 236,866 | 27,089 |
| Other | 117,222 | 48,918 |
| Total current liabilities | 1,984,356 | 1,062,660 |
| Long-term liabilities: | | |
| Deferred income taxes | 749,766 | 818,161 |
| Unrealized loss on derivative instruments | 158,423 | -- |
| Regulatory liabilities | 219,221 | 210,311 |
| Other deferred credits | 460,690 | 304,901 |
| Total long-term liabilities | 1,588,100 | 1,333,373 |
| Commitments and contingencies (Note 23) | | |
| Total capitalization and liabilities | $ 8,368,406 | $ 7,598,736 |

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

*Puget Energy Consolidated Statements of*

# CAPITALIZATION

(DOLLARS IN THOUSANDS)

| AT DECEMBER 31 | 2008 | 2007 |
|---|---|---|
| Common equity: | | |
| Common stock $0.01 par value, 250,000,000 shares authorized, 129,678,489 shares outstanding at December 31, 2008 and 2007 | $ 1,297 | $ 1,297 |
| Additional paid-in capital | 2,275,225 | 2,278,500 |
| Earnings reinvested in the business | 259,483 | 240,079 |
| Accumulated other comprehensive income (loss) – net of tax | (262,804) | 2,078 |
| Total common equity | 2,273,201 | 2,521,954 |
| Preferred stock subject to mandatory redemption – cumulative – $100 par value: * | | |
| 4.84% series –150,000 shares authorized, 14,583 shares outstanding at December 31, 2008 and 2007 | 1,458 | 1,458 |
| 4.70% series –150,000 shares authorized, 4,311 shares outstanding at December 31, 2008 and 2007 | 431 | 431 |
| Total preferred stock subject to mandatory redemption | 1,889 | 1,889 |
| Long-term debt: | | |
| First mortgage bonds and senior notes | 2,267,000 | 2,446,500 |
| Pollution control revenue bonds: | | |
| Revenue refunding 2003 series, due 2031 | 161,860 | 161,860 |
| Junior subordinated notes | 250,000 | 250,000 |
| Long-term debt due within one year | (158,000) | (179,500) |
| Total long-term debt excluding current maturities | 2,520,860 | 2,678,860 |
| Total capitalization | $ 4,795,950 | $ 5,202,703 |

** As of December 31, 2008, Puget Energy had 50,000,000 shares of $0.01 par value preferred stock authorized and PSE had 13,000,000 shares of $25 par value preferred stock authorized and 3,000,000 shares of $100 par value preferred stock authorized. All outstanding shares of preferred stock of PSE were defeased on February 5, 2009, to be redeemed on March 13, 2009. In connection with the merger, Puget Energy and PSE amended in their entirety their respective Articles of Incorporation and preferred stock is no longer authorized.*

*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, 2008, 2007 & 2006 | COMMON STOCK SHARES | COMMON STOCK AMOUNT | ADDITIONAL PAID-IN CAPITAL | RETAINED EARNINGS | ACCUMULATED OTHER COMPREHENSIVE INCOME | TOTAL AMOUNT |
|---|---|---|---|---|---|---|
| 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 |
| Net income | -- | -- | -- | 184,464 | -- | 184,464 |
| Common stock dividend declared | -- | -- | -- | (116,914) | -- | (116,914) |
| Common stock issued: | | | | | | |
| New issuance | 12,500,000 | 125 | 293,070 | -- | -- | 293,195 |
| Dividend reinvestment plan | 399,993 | 4 | 9,777 | -- | -- | 9,781 |
| Employee plans | 201,860 | 2 | 6,621 | -- | -- | 6,623 |
| Other comprehensive income | -- | -- | -- | -- | 28,776 | 28,776 |
| Balance at December 31, 2007 | 129,678,489 | $ 1,297 | $ 2,278,500 | $ 240,079 | $ 2,078 | $ 2,521,954 |
| Net income | -- | -- | -- | 154,929 | -- | 154,929 |
| Common stock dividend declared | -- | -- | -- | (129,677) | -- | (129,677) |
| Adjustment to initially apply SFAS No. 157 | -- | -- | -- | (5,848) | -- | (5,848) |
| Common stock issued: | | | | | | |
| Employee plans | -- | -- | (3,275) | -- | -- | (3,275) |
| Other comprehensive loss | -- | -- | -- | -- | (264,882) | (264,882) |
| Balance at December 31, 2008 | 129,678,489 | $ 1,297 | $ 2,275,225 | $ 259,483 | $ (262,804) | $ 2,273,201 |

*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 | 2008 | 2007 | 2006 |
|---|---|---|---|
| Net income | $ 154,929 | $ 184,464 | $ 219,216 |
| Other comprehensive income (loss): | | | |
| Foreign currency translation adjustment, net of tax of $0, $0 and $(176), respectively | -- | -- | (327) |
| Unrealized gain (loss) from pension and postretirement plans, net of tax of $(80,769), $16,083 and $2,376, respectively | (149,999) | 29,869 | 2,873 |
| Net unrealized gain (loss) on energy derivative instruments during the period, net of tax of $(73,621), $(6,776) and $(17,669), respectively | (136,725) | (12,584) | (32,813) |
| Reversal of net unrealized gains (losses) on energy derivative instruments settled during the period, net of tax of $11,590, $6,017 and $(2,972), respectively | 21,525 | 11,174 | (5,519) |
| Settlement of financing cash flow hedge contracts, net of tax of $0, $0 and $7,239, respectively | -- | -- | 13,443 |
| Amortization of financing cash flow hedge contracts to earnings, net of tax of $171, $171 and $289, respectively | 317 | 317 | 537 |
| Deferral of energy cash flow hedges related to the power cost adjustment mechanism, net of tax of $0, $0 and $3,367, respectively | -- | -- | 6,253 |
| Other comprehensive income (loss) | (264,882) | 28,776 | (15,553) |
| Comprehensive income (loss) | $(109,953) | $ 213,240 | $ 203,663 |

*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 | 2008 | 2007 | 2006 |
|---|---|---|---|
| Operating activities: | | | |
| Net income | $ 154, 929 | $ 184,464 | $ 219,216 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation and amortization | 312,128 | 279,222 | 262,341 |
| Conservation amortization | 61,650 | 39,955 | 32,299 |
| Deferred income taxes and tax credits, net | 80,596 | 66,820 | 20,613 |
| Power cost adjustment mechanism | (12) | 3,243 | 12,023 |
| Amortization of gas pipeline capacity assignment | (9,346) | (10,943) | (10,632) |
| Non cash return on regulatory assets | (9,860) | (10,194) | (12,438) |
| Net unrealized loss on derivative instruments | 7,538 | (2,687) | 71 |
| Gain on sale of InfrastruX | -- | -- | (29,765) |
| Impairment on InfrastruX investment | -- | -- | (7,269) |
| Other | 864 | 16,117 | (13,104) |
| Cash collateral paid from (returned to) energy suppliers | (159) | -- | (22,020) |
| Pension funding | (24,900) | -- | -- |
| Cash receipt from lease purchase option settlement | -- | 18,859 | -- |
| Chelan PUD contract initiation prepayment | -- | -- | (89,000) |
| Residential exchange program | 37,811 | (28,133) | (5,595) |
| Goldendale deferred costs | (288) | (11,505) | -- |
| Storm damage deferred costs | 3,294 | (29,274) | (92,331) |
| Change in certain current assets and liabilities: | | | |
| Accounts receivable and unbilled revenue | (29,405) | (4,652) | (78,179) |
| Materials and supplies | 89 | (18,613) | (6,093) |
| Fuel and gas inventory | (20,433) | 15,981 | (24,694) |
| Prepaid income taxes | 25,182 | (44,303) | -- |
| Prepayments and other | (3,055) | (2,681) | (4,319) |
| Purchased gas receivable / payable | (68,972) | 117,685 | 27,513 |
| Accounts payable | 21,420 | (52,678) | 36,038 |
| Taxes payable | 313 | 29,779 | (53,826) |
| Accrued expenses and other | (2,802) | 7,539 | 24,658 |
| Net cash provided by operating activities | 536,582 | 564,001 | 185,507 |
| Investing activities: | | | |
| Construction and capital expenditures – excluding equity AFUDC | (846,001) | (737,258) | (749,516) |
| Energy efficiency expenditures | (66,126) | (43,398) | (33,865) |
| Restricted cash | (14,096) | (141) | (3,605) |
| Cash proceeds from property sales | 2,248 | 6,468 | 936 |
| Refundable cash received for customer construction projects | 4,445 | 16,835 | 12,253 |
| Gross proceeds from sale of InfrastruX, net of cash disposed | -- | -- | 263,575 |
| Other | (12,325) | 495 | 5,500 |
| Net cash used by investing activities | (931,855) | (756,999) | (504,722) |
| Financing activities: | | | |
| Change in short-term debt and leases, net | 704,214 | (67,569) | 290,224 |
| Dividends paid | (129,677) | (108,434) | (104,332) |
| Issuance of common stock | -- | 300,544 | 5,878 |
| Issuance of bonds and notes | -- | 250,000 | 550,000 |
| Payments to minority shareholders of InfrastruX | -- | -- | (10,451) |
| InfrastruX debt redeemed | -- | -- | (141,221) |
| Redemption of trust preferred stock | -- | (37,750) | (200,000) |
| Redemption of bonds, notes and leases | (179,500) | (125,000) | (83,875) |
| Settlement of cash flow hedge of interest rate derivative | -- | -- | 20,682 |
| Issuance and redemption costs of bonds and other | (2,035) | (6,113) | (2,467) |
| Net cash provided by financing activities | 393,002 | 205,678 | 324,438 |
| Net increase (decrease) in cash | (2,271) | 12,680 | 5,223 |
| Cash at beginning of year | 40,797 | 28,117 | 22,894 |
| Cash at end of year | $ 38,526 | $ 40,797 | $ 28,117 |
| Supplemental cash flow information: | | | |
| Cash payments for interest (net of capitalized interest) | $ 204,837 | $ 196,180 | $ 167,789 |
| Cash payments (refunded) for income taxes | (42,338) | 26,897 | 129,100 |

*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 | 2008 | 2007 | 2006 |
|---|---|---|---|
| Operating revenues: | | | |
| Electric | $ 2,129,463 | $ 1,997,829 | $ 1,777,745 |
| Gas | 1,216,868 | 1,208,029 | 1,120,118 |
| Non-utility operating revenues | 11,442 | 14,289 | 9,200 |
| Total operating revenues | 3,357,773 | 3,220,147 | 2,907,063 |
| Operating expenses: | | | |
| Energy costs: | | | |
| Purchased electricity | 903,317 | 895,592 | 917,801 |
| Electric generation fuel | 212,333 | 143,406 | 97,320 |
| Residential exchange | (40,664) | (52,439) | (163,622) |
| Purchased gas | 737,851 | 762,112 | 723,232 |
| Unrealized (gain) loss on derivative instruments | 7,538 | (2,687) | 71 |
| Utility operations and maintenance | 461,632 | 403,681 | 354,590 |
| Non-utility expense and other | 12,399 | 12,429 | 4,531 |
| Depreciation and amortization | 312,128 | 279,222 | 262,341 |
| Conservation amortization | 61,650 | 39,955 | 32,320 |
| Taxes other than income taxes | 297,203 | 288,492 | 255,797 |
| Total operating expenses | 2,965,387 | 2,769,763 | 2,484,381 |
| Operating income | 392,386 | 450,384 | 422,682 |
| Other income (deductions): | | | |
| Other income | 33,239 | 28,938 | 28,236 |
| Other expense | (7,215) | (7,509) | (6,594) |
| Interest charges: | | | |
| AFUDC | 8,610 | 12,614 | 15,874 |
| Interest expense | (202,588) | (217,823) | (184,013) |
| Interest expense on Puget Energy note | (814) | (1,296) | (845) |
| Income before income taxes | 223,618 | 265,308 | 275,340 |
| Income tax expense | 60,882 | 74,181 | 98,689 |
| Net income before cumulative effect of accounting change | 162,736 | 191,127 | 176,651 |
| Cumulative effect of implementation of accounting change (net of tax) | -- | -- | 89 |
| Net income | $ 162,736 | $ 191,127 | $ 176,740 |

*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 | 2008 | 2007 |
|---|---|---|
| Utility plant: | | |
| Electric plant | $ 6,596,359 | $ 5,914,127 |
| Gas plant | 2,500,236 | 2,313,477 |
| Common plant | 550,368 | 506,211 |
| Less: Accumulated depreciation and amortization | (3,358,816) | (3,091,176) |
| Net utility plant | 6,288,147 | 5,642,639 |
| Other property and investments: | | |
| Investment in Bonneville Exchange Power contract | 29,976 | 33,503 |
| Other property and investments | 118,039 | 114,083 |
| Total other property and investments | 148,015 | 147,586 |
| Current assets: | | |
| Cash | 38,470 | 40,773 |
| Restricted cash | 18,889 | 798 |
| Accounts receivable, net of allowance for doubtful accounts | 207,776 | 219,345 |
| Secured pledged accounts receivable | 158,000 | 152,000 |
| Unbilled revenues | 248,649 | 210,025 |
| Materials and supplies, at average cost | 62,024 | 62,114 |
| Fuel and gas inventory, at average cost | 120,205 | 99,772 |
| Unrealized gain on derivative instruments | 15,618 | 17,130 |
| Prepaid income taxes | 17,317 | 41,814 |
| Prepaid expenses and other | 14,420 | 11,365 |
| Deferred income taxes | 9,439 | 4,011 |
| Total current assets | 910,807 | 859,147 |
| Other long-term assets: | | |
| Regulatory asset for deferred income taxes | 95,417 | 104,928 |
| Regulatory asset for PURPA buyout costs | 110,838 | 140,520 |
| Power cost adjustment mechanism | 3,126 | 3,114 |
| Other regulatory assets | 766,732 | 510,998 |
| Unrealized gain on derivative instruments | 6,712 | 11,845 |
| Other | 40,365 | 171,433 |
| Total other long-term assets | 1,023,190 | 942,838 |
| Total assets | $ 8,370,159 | $ 7,592,210 |

*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 | 2008 | 2007 |
|---|---|---|
| Capitalization: | | |
| *(See Consolidated Statements of Capitalization):* | | |
| Common equity | $ 2,249,186 | $ 2,504,091 |
| Total shareholder's equity | 2,249,186 | 2,504,091 |
| Redeemable securities and long-term debt: | | |
| Preferred stock subject to mandatory redemption | 1,889 | 1,889 |
| Junior subordinated notes | 250,000 | 250,000 |
| Long-term debt | 2,270,860 | 2,428,860 |
| Total redeemable securities and long-term debt | 2,522,749 | 2,680,749 |
| Total capitalization | 4,771,935 | 5,184,840 |
| Current liabilities: | | |
| Accounts payable | 341,255 | 310,083 |
| Short-term debt | 964,700 | 260,486 |
| Short-term note owed to Puget Energy | 26,053 | 15,766 |
| Current maturities of long-term debt | 158,000 | 179,500 |
| Accrued expenses: | | |
| Purchased gas liability | 8,892 | 77,864 |
| Taxes | 85,068 | 84,756 |
| Salaries and wages | 35,280 | 28,516 |
| Interest | 36,112 | 45,209 |
| Unrealized loss on derivative instruments | 236,866 | 27,089 |
| Other | 117,223 | 48,918 |
| Total current liabilities | 2,009,449 | 1,078,187 |
| Long-term liabilities: | | |
| Deferred income taxes | 750,440 | 821,382 |
| Unrealized loss on derivative instruments | 158,423 | -- |
| Regulatory liabilities | 219,221 | 210,372 |
| Other deferred credits | 460,691 | 297,429 |
| Total long-term liabilities | 1,588,775 | 1,329,183 |
| Commitments and contingencies (Note 23) | | |
| Total capitalization and liabilities | $ 8,370,159 | $ 7,592,210 |

*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 | 2008 | 2007 |
|---|---|---|
| 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 | 1,296,005 | 1,297,076 |
| Earnings reinvested in the business | 356,947 | 345,899 |
| Accumulated other comprehensive income (loss) – net of tax | (262,804) | 2,078 |
| Total common equity | 2,249,186 | 2,504,091 |
| Preferred stock subject to mandatory redemption – cumulative - | | |
| $100 par value:* | | |
| 4.84% series – 150,000 shares authorized, | | |
| 14,583 shares outstanding at December 31, 2008 and 2007 | 1,458 | 1,458 |
| 4.70% series – 150,000 shares authorized, | | |
| 4,311 shares outstanding at December 31, 2008 and 2007 | 431 | 431 |
| Total preferred stock subject to mandatory redemption | 1,889 | 1,889 |
| Long-term debt: | | |
| First mortgage bonds and senior notes | 2,267,000 | 2,446,500 |
| Pollution control revenue bonds: | | |
| Revenue refunding 2003 series, due 2031 | 161,860 | 161,860 |
| Junior subordinated notes | 250,000 | 250,000 |
| Long-term debt due within one year | (158,000) | (179,500) |
| Total long-term debt excluding current maturities | 2,520,860 | 2,678,860 |
| Total capitalization | $ 4,771,935 | $ 5,184,840 |

**As of December 31, 2008, PSE had 13,000,000 shares of $25 par value preferred stock authorized and 3,000,000 shares of $100 par value preferred stock authorized. All outstanding shares of preferred stock of PSE were defeased on February 5, 2009, to be redeemed on March 13, 2009. In connection with the merger, PSE amended and restated in its entirety its Articles of Incorporation and preferred stock is no longer authorized.*

*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, 2008, 2007 & 2006 | COMMON STOCK SHARES | COMMON STOCK AMOUNT | ADDITIONAL PAID-IN CAPITAL | RETAINED EARNINGS | ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS) | TOTAL AMOUNT |
|---|---|---|---|---|---|---|
| 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 loss | -- | -- | -- | -- | (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 |
| Net income | -- | -- | -- | 191,127 | -- | 191,127 |
| Common stock dividend declared | -- | -- | -- | (108,434) | -- | (108,434) |
| Investment received from Puget Energy | -- | -- | 300,339 | -- | -- | 300,339 |
| Other comprehensive income | -- | -- | -- | -- | 28,776 | 28,776 |
| Balance at December 13, 2007 | 85,903,791 | $ 859,038 | $ 1,297,076 | $ 345,899 | $ 2,078 | $ 2,504,091 |
| Net income | -- | -- | -- | 162,736 | -- | 162,736 |
| Common stock dividend declared | -- | -- | -- | (145,840) | -- | (145,840) |
| Adjustment to initially apply SFAS No. 157 | -- | -- | -- | (5,848) | -- | (5,848) |
| Investment sent to Puget Energy | -- | -- | (1,071) | -- | -- | (1,071) |
| Other comprehensive loss | -- | -- | -- | -- | (264,882) | (264,882) |
| Balance at December 31, 2008 | 85,903,791 | $ 859,038 | $ 1,296,005 | $ 356,947 | $ (262,804) | $ 2,249,186 |

*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 | 2008 | 2007 | 2006 |
|---|---|---|---|
| Net income | $ 162,736 | $ 191,127 | $ 176,740 |
| Other comprehensive income (loss): | | | |
| Unrealized gain (loss) from pension and postretirement plans, net of tax of $(80,769), $16,083 and $2,376, respectively | (149,999 ) | 29,869 | 2,873 |
| Net unrealized gain (loss) on energy derivative instruments during the period, net of tax of $(73,621), $(6,776) and $(17,669), respectively | (136,725 ) | (12,584 ) | (32,813 ) |
| Reversal of net unrealized gains (losses) on energy derivative instruments settled during the period, net of tax of $11,590, $6,017 and $(2,972), respectively | 21,525 | 11,174 | (5,519 ) |
| Settlement of financing cash flow hedge contracts, net of tax of $0, $0 and $7,239, respectively | -- | -- | 13,443 |
| Amortization of financing cash flow hedge contracts to earnings, net of tax of $171, $171 and $289, respectively | 317 | 317 | 537 |
| Deferral of energy cash flow hedges related to the power cost adjustment mechanism, net of tax of $0, $0 and $3,367, respectively | -- | -- | 6,253 |
| Other comprehensive income (loss) | (264,882 ) | 28,776 | (15,226 ) |
| Comprehensive income (loss) | $ (102,146 ) | $ 219,903 | $ 161,514 |

*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 | 2008 | 2007 | 2006 |
|---|---|---|---|
| Operating activities: | | | |
| Net income | $ 162,736 | $ 191,127 | $ 176,740 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation and amortization | 312,128 | 279,222 | 262,341 |
| Conservation amortization | 61,650 | 39,955 | 32,299 |
| Deferred income taxes and tax credits, net | 78,050 | 66,102 | 34,283 |
| Power cost adjustment mechanism | (12) | 3,243 | 12,023 |
| Amortization of gas pipeline capacity assignment | (9,346) | (10,943) | (10,632) |
| Non cash return on regulatory assets | (9,860) | (10,194) | (12,438) |
| Net unrealized loss on derivative instruments | 7,538 | (2,687) | 71 |
| Other | 10,499 | 17,252 | (9,369) |
| Cash collateral paid from (returned to) energy suppliers | (159) | -- | (22,020) |
| Pension funding | (24,900) | -- | -- |
| Cash receipt from lease purchase option settlement | -- | 18,859 | -- |
| Chelan PUD contract initiation prepayment | -- | -- | (89,000) |
| Residential exchange program | 37,811 | (28,133) | (5,595) |
| Goldendale deferred costs | (288) | (11,505) | -- |
| Storm damage deferred costs | 3,294 | (29,274) | (92,331) |
| Change in certain current assets and current liabilities: | | | |
| Accounts receivable and unbilled revenue | (33,055) | (5,215) | (64,961) |
| Materials and supplies | 89 | (18,613) | (7,010) |
| Fuel and gas inventory | (20,433) | 15,981 | (24,694) |
| Prepaid income taxes | 24,497 | (41,814) | -- |
| Prepayments and other | (3,055) | (2,706) | (1,636) |
| Purchased gas receivable / payable | (68,972) | 117,685 | 27,513 |
| Accounts payable | 20,735 | (52,908) | 33,004 |
| Taxes payable | 313 | 29,391 | (56,535) |
| Accrued expenses and other | (2,840) | 8,164 | 30,588 |
| Net cash provided by operating activities | 546,420 | 572,989 | 212,641 |
| Investing activities: | | | |
| Construction expenditures – excluding equity AFUDC | (846,001) | (737,258) | (745,239) |
| Energy efficiency expenditures | (66,126) | (43,398) | (33,865) |
| Restricted cash | (18,090) | 495 | 208 |
| Cash received from property sales | 2,248 | 6,468 | 936 |
| Refundable cash received for customer construction projects | 4,445 | 16,835 | 12,253 |
| Other | (12,325) | 40 | 5,500 |
| Net cash used by investing activities | (935,849) | (756,818) | (760,207) |
| Financing activities: | | | |
| Change in short-term debt and leases, net | 704,214 | (67,569) | 287,055 |
| Dividends paid | (145,840) | (108,434) | (109,782) |
| Issuance of bonds and notes | -- | 250,000 | 550,000 |
| Loan (payment) from/to Puget Energy | 10,287 | (8,537) | 24,303 |
| Redemption of trust preferred stock | -- | (37,750) | (200,000) |
| Redemption of bond, notes and leases | (179,500) | (125,000) | (81,000) |
| Settlement of cash flow hedge interest rate derivative | -- | -- | 20,682 |
| Investment from Puget Energy | -- | 297,073 | 70,114 |
| Issuance and redemption cost of bonds and other | (2,035) | (3,273) | (2,423) |
| Net cash provided by financing activities | 387,126 | 196,510 | 558,949 |
| Net increase (decrease) in cash | (2,303) | 12,681 | 11,383 |
| Cash at beginning of year | 40,773 | 28,092 | 16,709 |
| Cash at end of year | $ 38,470 | $ 40,773 | $ 28,092 |
| Supplemental cash flow information: | | | |
| Cash payments for interest (net of capitalized interest) | $ 204,837 | $ 196,180 | $ 164,389 |
| Cash payments (refunded) for income taxes | (40,034) | 26,897 | 123,100 |

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

## NOTE 1. *Summary of Significant Accounting Policies*

### BASIS OF PRESENTATION

Puget Energy, Inc. (Puget Energy) is a holding company that owns Puget Sound Energy, Inc. (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 natural gas services in a territory covering 6,000 square miles, primarily in the Puget Sound region.

The 2008 consolidated financial statements of Puget Energy reflect the accounts of Puget Energy and its subsidiary, PSE. 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 to current year presentations with no effect on total equity or net income.

The 2006 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 until May 7, 2006, a 90.9% interest in InfrastruX. The results of PSE and InfrastruX are presented on a consolidated basis. The financial position and results of operations for InfrastruX are presented as discontinued operations. 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 provided construction services to the electric and natural gas utility industries primarily in the Midwest, Texas, south-central and eastern United States regions.

The preparation of financial statements in conformity with generally accepted accounting principles (GAAP) 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.

### 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 2.8% in 2008, 2.9% in 2007, and 2.9% in 2006; depreciable gas utility plant was 3.4% in 2008, 3.4% in 2007, and 3.3% in 2006; and depreciable common utility plant was 5.8% in 2008, 5.1% in 2007, and 5.1% in 2006. 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 $18.9 million and $4.8 million at December 31, 2008 and 2007, respectively. The restricted cash balance in both 2008 and 2007 includes $0.8 million which represents funds held by Puget Western, Inc., a PSE subsidiary, for a real estate development project. As of December 31, 2008, other restricted cash includes $12.2 in a Bonneville Power Administration (BPA) Transmission escrow account, and $4.2 million in a Benefit Protection Trust. As of December 31, 2007, $4.0 million represented 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 natural 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 natural gas customers. Fuel inventory consists of coal, diesel, and natural gas used for generation. Gas inventory consists of natural gas and liquefied natural gas (LNG) 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 Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71). 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 (PGA) payable which is a current liability.

The Company was allowed a return on the net regulatory assets and liabilities of 8.4%, or 7.01% after-tax, for both electric and natural gas rates for the period March 4, 2005 through January 12, 2007. Effective January 13, 2007 based on the 2006 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 natural gas rates. Effective November 1, 2008, the Company was allowed 8.25%, or 7.00% after tax, for both electric and natural gas rates. The net regulatory assets and liabilities at December 31, 2008 and 2007 included the following:

| (DOLLARS IN MILLIONS) | REMAINING AMORTIZATION PERIOD | 2008 | 2007 |
|---|---|---|---|
| PGA deferral of unrealized (gain) losses on derivative instruments | * | $ 187.2 | $ 6.0 |
| Storm damage costs – electric | 4 to 10 years | 120.1 | 127.4 |
| Chelan PUD contract initiation | ** | 114.8 | 105.2 |
| PURPA electric energy supply contract buyout costs | 3 years | 110.8 | 140.5 |
| Deferred income taxes | * | 95.4 | 104.9 |
| Baker Dam licensing operating and maintenance costs | *** | 73.9 | -- |
| White River relicensing and other costs | **** | 71.0 | 72.5 |
| Environmental remediation | ******** | 54.5 | 37.8 |
| Deferred allowance for funds used during construction (AFUDC) | 29 years | 42.8 | 36.3 |
| Investment in Bonneville Exchange Power contract | 8.5 years | 30.0 | 33.5 |
| Goldendale ownership and operating costs | 3 years | 11.8 | 11.5 |
| Tree watch costs | 6.3 years | 11.0 | 15.3 |
| Colstrip common property | 15.5 years | 11.1 | 11.8 |
| Hopkins Ridge prepaid transmission upgrade | 3 years | 4.7 | 7.2 |
| Power cost adjustment (PCA) mechanism | * | 3.1 | 3.1 |
| Residential Exchange | 1.9 years | 2.8 | 35.7 |
| Carrying costs on income tax payments | Less than 1 year | 0.1 | 3.4 |
| Various other regulatory assets | 1 to 27.5 years | 61.0 | 40.9 |
| Total regulatory assets | | $ 1,006.1 | $ 793.0 |
| Cost of removal | ****** | $ (156.7) | $ (137.9) |
| Purchased gas adjustment (PGA) payable | * | (8.9) | (77.9) |
| Deferred credit gas pipeline capacity | 3 to 9.8 years | (24.1) | (33.4) |
| Summit Purchase Option Buy-Out | ******* | (18.6) | (18.9) |
| Deferred gains on property sales | 3 years | (11.9) | (12.7) |
| Gas supply contract settlement | N/A | -- | (1.9) |
| Various other regulatory liabilities | 1.8 to 7.5 years | (7.9) | (5.6) |
| Total regulatory liabilities | | $ (228.1) | $ (288.3) |
| Net regulatory assets and liabilities | | $ 778.0 | $ 504.7 |

* *Amortization period varies depending on timing of underlying transactions.*
** *Amortization period will start in 2011 for a 20-year period.*
*** *Costs are being recovered over the life of license term of 50 years.*
**** *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.*
******* *Amortization period started November 1, 2008 and will be amortized over 12 years.*
******** *Amortization period will start for a five-year period once all costs and insurance recoveries are known.*

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" (SFAS No. 101). 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 $156.7 million, and $137.9 million in 2008 and 2007, 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 natural 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 $8.1 million for 2008, $4.4 million for 2007, and $2.7 million for 2006. The deferred asset is being amortized over the average useful life of the Company's non-project electric utility plant.

### CALIFORNIA RECEIVABLE

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 (ALJ). The amount of the receivable, $21.1 million at December 31, 2008, 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" (EITF No. 03-11). Non-utility subsidiaries recognize revenue when services are performed or upon the sale of assets. Revenue from retail sales is billed based on tariff rates approved by the Washington Commission.

PSE collected Washington State excise taxes (which are a component of general retail rates) and municipal taxes of $240.5 million, $229.0 million and $203.7 million for 2008, 2007 and 2006, 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, 2008 and 2007 was $6.4 million, and $5.5 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 for the years ending 2006 through 2008 and $8.0 million for subsequent years 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" (SFAS No. 109). Uncertain tax positions are accounted for under FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48). The Company classifies interest as interest expense and penalties as other expense in the financial statements.

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 for ratemaking purposes at each general rate case.

Since 1995, the Company has been authorized by the Washington Commission to defer natural 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, natural gas energy efficiency expenditures have no direct impact on earnings.

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.

As part of PSE's 2006 General Rate Case, the Washington Commission allows PSE to collect an electric incentive through ratepayers via rate riders if PSE exceeds annual baseline savings. If PSE does not achieve the target savings then PSE is subject to penalties for both electric and gas conservation programs.

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 varies from a baseline power cost rate established in a rate proceeding. 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" (SFAS No. 133), 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 |
|---|---|---|---|
| +/- $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.*

The differences between the actual cost of PSE's natural gas supplies and natural gas transportation contracts and costs currently allowed by the Washington Commission are deferred and recovered or repaid through the 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 natural gas supplies and holds firm transportation and storage capacity sufficient to meet the expected peak winter demand for natural 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 natural 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 natural gas sales, exchanges and capacity releases. The Company sells excess natural gas supplies, enters into natural gas supply exchanges with third parties outside of its distribution area and releases to third parties excess interstate natural gas pipeline capacity and natural gas storage rights on a short-term basis to mitigate the costs of firm transportation and storage capacity for its core natural gas customers. The proceeds from such activities, net of transactional costs, are accounted for as reductions in the cost of purchased natural 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 natural gas.

### ACCOUNTING FOR DERIVATIVES

The Company follows the provisions of SFAS No. 133, as amended by SFAS No. 138, “Accounting for Certain Derivative Instruments and Certain Hedging Activities-an amendment of FASB Statement No. 133” (SFAS No. 138) and SFAS No. 149, “Amendment of Statement 133 on Derivative Instruments and Hedging Activities” (SFAS No. 149), which require 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 (NPNS) exception. The Company enters into both physical and financial contracts to manage its energy resource portfolio. The majority of the Company’s physical contracts qualify for the NPNS exception for the purpose of serving retail load. However, those contracts that do not meet the NPNS 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 natural gas for the Company’s retail natural 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.

### FAIR VALUE MEASUREMENTS

As defined in SFAS No. 157, “Fair Value Measurements” (SFAS No. 157), fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). However, as permitted under SFAS No. 157, the Company utilizes a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient for valuing the majority of its assets and liabilities measured and reported at fair value. The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The Company primarily applies the market approach for recurring fair value measurements and endeavors to utilize the best available information. Accordingly, the Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

The Company values derivative instruments based on daily quoted prices from an independent external pricing service. When external quoted market prices are not available for derivative contracts, the Company 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. The Company is focused on commodity price exposure and risks associated with volumetric variability in the natural gas and electric portfolios. It is not engaged in the business of assuming risk for the purpose of speculative trading. The Company hedges open natural 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 250 simulations of how the Company's natural gas and power portfolios will perform under various weather, hydro and unit performance conditions. The Company has not made any material changes during the reporting period to those techniques or models.

As a result of the recent credit crisis, the FASB recently issued Staff Position (FSP) No. 157-3, "Determining the Fair Value of a Financial Asset in a Market That is Not Active" (FSP No. 157-3). FSP No. 157-3 clarifies the application of SFAS No. 157 in a market that is not active. As of December 31, 2008, the Company considers the markets for its electric and natural gas Level 2 derivative instruments to be actively traded. Management's assessment is based on the trading activity volume in real-time and forward electric and natural gas markets. The Company regularly confirms the validity of pricing service quoted prices (e.g. Level 2 in the fair value hierarchy) used to value commodity contracts to the actual prices of commodity contracts entered into during the most recent quarter. The Company has concluded that this FSP did not have a significant impact to existing processes.

### STOCK-BASED COMPENSATION

The Company applies the fair value approach to stock compensation and estimates fair value in accordance with provisions of SFAS No. 123R "Share Based Payments."

### 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 129,437,000, 117,673,000 and 115,999,000 for 2008, 2007 and 2006, respectively. Diluted earnings per common share has been computed based on weighted-average common shares outstanding of 130,094,000, 118,344,000, and 116,457,000 for 2008, 2007 and 2006, respectively, which includes the dilutive effect of securities related to employee stock-based compensation plans. In 2007, 1,300 shares related to stock options were excluded from the diluted weighted-average common share calculation due to their anti-dilutive effect. No shares related to stock options were excluded in 2008.

### ACCOUNTS RECEIVABLE SECURITIZATION PROGRAM

In December 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. In addition, PSE Funding entered into a Loan and Servicing Agreement with PSE and two banks. The Loan and Servicing Agreement allowed 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 was terminated upon the closing of the merger on February 6, 2009 and the outstanding balance was paid in full. PSE Funding had $158.0 million and $152.0 million of loans secured by accounts receivable pledged as collateral at December 31, 2008 and 2007, respectively.

### 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, 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 PCA mechanism. The following table presents the Company's accumulated other comprehensive gain (loss) net of tax at December 31:

| (DOLLARS IN THOUSANDS) | 2008 | 2007 |
|---|---|---|
| Unrealized losses on derivatives during the period | $(139,723) | $ (3,000) |
| Reversal of unrealized losses on derivatives during the period | 28,007 | 6,483 |
| Settlement of cash flow hedge contract | 13,443 | 13,443 |
| Amortization of cash flow hedge contracts | (21,335) | (21,652) |
| Unrealized (loss)\gain and prior service cost on pension plans | (143,196) | 6,804 |
| Total Puget Energy, net of tax | $(262,804) | $ 2,078 |

NOTE 2. *New Accounting Pronouncements*

On March 19, 2008, FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities – An Amendment of FASB Statement No. 133" (SFAS No. 161). SFAS No. 161 is effective for the fiscal years and interim years beginning after November 15, 2008, and the Company has early adopted this pronouncement. SFAS No. 161 requires companies with derivative instruments to disclose information that should enable financial statement users to understand how and why a company uses derivative instruments, how derivative instruments and related hedged items are accounted for under SFAS No. 133 and how derivative instruments and related hedged items affect a company's financial position, financial performance and cash flows. SFAS No. 161 requirements will impact the following derivative and hedging disclosures: objectives and strategies, balance sheet, financial performance, contingent features and counterparty credit risk.

In May 2008, FASB issued SFAS No. 162, "The Hierarchy of Generally Accepted Accounting Principles" (SFAS No. 162), which identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements of nongovernmental entities that are presented in conformity with GAAP. FASB is responsible for identifying the sources of accounting principles and providing entities with a framework for selecting the principles used in the preparation of financial statements. The Company has reviewed SFAS No. 162 and has assessed that there will be no significant impact to the financial statements.

On December 30, 2008, FASB issued FSP No. 132R-1, "Employers' Disclosures about Postretirement Benefit Plan Assets" (FSP No. 132R-1). FSP No. 132R-1 directs companies to provide additional disclosures about plan assets of a defined benefit pension or other postretirement plan. The objectives of the disclosures are to provide users of financial statements with an understanding of: (1) how investment allocation decisions are made, including the factors that are pertinent to an understanding of investment policies and strategies, (2) major categories of plan assets, (3) inputs and valuation techniques used to measure the fair value of plan assets, (4) effect of fair value measurements using significant unobservable inputs (Level 3) on changes in plan assets for the period, and (5) significant concentrations of risk within plan assets. FSP No. 132R-1 is effective for the fiscal years ending after December 15, 2009, which will be for the fiscal year ending December 31, 2009, for the Company. The Company is currently assessing the impact of FSP No. 132R-1 on its disclosures.

In December 2008, FASB issued FIN 46R-8, "Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interests in Variable Interest Entities" (FIN 46R-8), which requires new expanded disclosures in the financial statements for year ended December 31, 2008 for variable interest entities (VIEs). FIN 46R-8 amends Interpretation 46R to require certain disclosures by a public enterprise that is (a) a sponsor that has a variable interest in a VIE (irrespective of the significance of the variable interest) and (b) an enterprise that holds a significant variable interest in a qualifying special purpose entity (SPE) but was not the transferor (nontransferor enterprise) of financial assets to the qualifying SPE. The disclosures required by FIN 46R-8 are intended to provide users of the financial statements with greater transparency about a transferor's continuing involvement with transferred financial assets and an enterprise's involvement with VIEs.

In December 2007, the FASB issued SFAS No. 141(R), "Business Combinations" (SFAS No. 141(R)). SFAS No. 141(R) replaces FASB Statement No. 141, "Business Combinations," and addresses the accounting for all transactions or other events in which an entity obtains control of one or more businesses. The objective of SFAS No. 141(R)is to improve the relevance, representational faithfulness and comparability of the information that a reporting entity provides in its financial reports about a business combination and its effects. To accomplish that, SFAS No. 141(R) establishes principles and requirements for how the acquirer: (1) recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree, (2) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase, and (3) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS No. 141(R) shall be applied prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. The Company will apply this standard for any business combinations beginning on January 1, 2009.

On September 15, 2006, FASB issued SFAS No. 157, which clarifies how companies should use fair value measurements in accordance with GAAP for recognition and disclosure purposes. SFAS No. 157 establishes a common definition of fair value and a framework for measuring fair value under GAAP, along with expanding disclosures about fair value to eliminate differences in current practice that exist in measuring fair value under the existing accounting standards. The definition of fair value in SFAS No. 157 retains the notion of exchange price; however, it focuses on the price that would be received to sell the asset or paid to transfer a liability (i.e. an exit price), rather than the price that would be paid to acquire the asset or received to assume the liability (i.e. an entrance price). Under SFAS No. 157, a fair value measure should reflect all of the assumptions that market participants would use in pricing the asset or liability, including assumptions about the risk inherent in a particular valuation technique, the effect of a restriction on the sale or use of an asset, and the risk of nonperformance. To increase consistency and comparability in fair value measures, SFAS No. 157 establishes a three-level fair value hierarchy to prioritize the inputs used in valuation techniques between observable inputs that reflect quoted market prices in active markets, inputs other than quoted prices with observable market data, and unobservable data (e.g. a company's own data).

SFAS No. 157 is effective for fiscal years beginning after November 15, 2007, which was the year beginning January 1, 2008, for the Company. On February 28, 2008, the FASB issued a final FSP that partially deferred the effective date of SFAS No. 157 for one year for non-financial assets and non-financial liabilities that are recognized or disclosed at fair value, except for those that are recognized or disclosed at fair value on an annual or more frequent basis. The Company adopted SFAS No. 157 on January 1, 2008, prospectively, as required by the Statement, with certain exceptions, including the initial impact of changes in fair value measurements of existing derivative financial instruments measured initially using the transaction price under EITF No. 02-3 "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposed and Contracts Involved in Energy Trading and Risk Management Activities" (EITF No. 02-3).

SFAS No. 157 nullified a portion of EITF No. 02-3. Under EITF No. 02-3, the transaction price presumption prohibited recognition of a trading profit at inception of a derivative unless the positive fair value of that derivative was substantially based on quoted prices or a valuation process incorporating observable inputs. For transactions that did not meet this criterion at inception, trading profits that had been deferred were recognized in the period that inputs to value the derivative became observable or when the contract performed. On January 1, 2008, the difference between the carrying amounts and the fair values of those instruments originally recorded under guidance in EITF No. 02-3 was recognized as a cumulative-effect adjustment to the opening balance of retained earnings of $9.0 million before tax as a result of recording a deferred loss on net derivative assets and liabilities.

As a result of the recent credit crisis, on October 10, 2008, the FASB issued FSP No. 157-3. FSP No. 157-3 clarifies the application of SFAS No. 157 in a market that is not active. FSP No. 157-3 addresses how management should consider measuring fair value when relevant observable data does not exist. FSP No. 157-3 also provides guidance on how observable market information in a market that is not active should be considered when measuring fair value, as well as how the use of market quotes should be considered when assessing the relevance of observable and unobservable data available to measure fair value. FSP No. 157-3 was effective upon issuance, including prior periods for which financial statement have not been issued. Revisions resulting from a change in the valuation technique or its application shall be accounted for as a change in accounting estimate (FASB Statement No. 154, "Accounting Changes and Error Corrections," (SFAS No. 154) paragraph 19). The disclosure provisions of SFAS No. 154 for a change in accounting estimate are not required for revisions resulting from a change in valuation technique or its application. The Company has reviewed the statement and has assessed that there will be no significant impact to the financial statements.

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) in an all-cash transaction. Puget Energy accounted for InfrastruX as a discontinued operation under SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144) in 2006. As a part of the transaction, Puget Energy made certain representations and warrantees concerning InfrastruX and indemnified Tenaska against certain future losses not to exceed $15.0 million. At the time of the sale, Puget Energy purchased a warrantee insurance policy and deposited $3.7 million into an escrow account, representing the full retention under the insurance policy. Additionally at the time of sale, Puget Energy recorded a $5.0 million loss reserve in connection with the indemnifications, which represented management's measurement of the fair value of the corporate guarantees using a probability weighted approach.

On April 29, 2008, Puget Energy and Tenaska entered into a Joint Notice of Distribution and Termination Agreement (Termination Agreement) which resulted in the extinguishment of all InfrastruX corporate guarantees made by Puget Energy which management believed involved a risk of loss in connection with the sale of InfrastruX. In the second quarter 2008, Puget Energy made the remaining payments under the terms of the Termination Agreement totaling $7.1 million bringing total cash outlays equal to the Company's original aggregate loss reserve amounts recorded in the second quarter of 2006.

| | Twelve Months Ended December 31, | |
|---|---|---|
| (Dollars in Thousands) | 2007 | 2006[1] |
| Revenues | $ -- | $ 138,573 |
| Goodwill impairment | -- | -- |
| Operating expenses (including interest expense) | -- | (128,605) |
| Pre-tax income | -- | 9,968 |
| Income tax expense | -- | (3,544) |
| Puget Energy carrying value adjustment of InfrastruX | -- | 7,269 |
| Puget Energy cost of sale related to InfrastruX, net of tax of $(114) and $(505) | (212) | (937) |
| Puget Energy deferred tax basis adjustment of InfrastruX | -- | 9,966 |
| Gain on sale, net of tax of $0 and $16,207 | -- | 29,765 |
| Minority interest in income of discontinued operations | -- | (584) |
| Income (loss) from discontinued operations | $ (212) | $ 51,903 |

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

NOTE 4. *Utility and Non-Utility Plant*

| UTILITY PLANT (DOLLARS IN THOUSANDS) AT DECEMBER 31 | ESTIMATED USEFUL LIFE (YEARS) | 2008 | 2007 |
|---|---|---|---|
| Electric, gas and common utility plant classified by prescribed accounts at original cost: | | | |
| Distribution plant | 10-55 | $ 5,429,830 | $ 5,107,272 |
| Production plant | 25-125 | 2,330,116 | 2,021,239 |
| Transmission plant | 45-65 | 352,042 | 334,958 |
| General plant | 5-35 | 407,367 | 372,369 |
| Whitehorn capital lease | * | 22,665 | 22,840 |
| Fredonia capital lease | 1 | 47,247 | -- |
| Construction work in progress | NA | 255,214 | 267,594 |
| Intangible plant (including capitalized software) | 3-50 | 381,880 | 322,005 |
| Plant acquisition adjustment | NA | 228,772 | 77,871 |
| Underground storage | 25-60 | 27,602 | 24,492 |
| Liquefied natural gas storage | 25-45 | 14,310 | 14,310 |
| Plant held for future use | NA | 16,829 | 8,623 |
| Other | NA | 7,037 | 6,299 |
| Plant not classified | NA | 126,052 | 153,943 |
| Less: accumulated provision for depreciation | | (3,358,816) | (3,091,176) |
| Net utility plant | | $ 6,288,147 | $ 5,642,639 |

* *Less than one year*

| NON-UTILITY PLANT (DOLLARS IN THOUSANDS) AT DECEMBER 31 | 2008 | 2007 |
|---|---|---|
| Non-utility plant | $ 1,744 | $ 3,040 |
| Less: accumulated provision for depreciation | (447) | (445) |
| Net non-utility plant | $ 1,297 | $ 2,595 |

In 2007, the Company recognized an asset retirement obligation (ARO) related to a settlement agreement requiring the company to replace steel wrapped services categorized as being identified for replacement or priority replacements. In 2008, the Company recognized an ARO for the decommissioning costs for the Wild Horse wind farm (Wild Horse) for the 43 turbines on lands owned by two state of Washington agencies.

The following table describes all changes to the Company's ARO liability:

| (DOLLARS IN THOUSANDS) AT DECEMBER 31 | 2008 | 2007 |
|---|---|---|
| Asset retirement obligation at beginning of year | $ 29,608 | $ 28,356 |
| New asset retirement obligation liability recognized in the period | 498 | 1,733 |
| Liability settled in the period | (1,819) | (1,597) |
| Accretion expense | 1,374 | 1,116 |
| Asset retirement obligation at December 31 | $ 29,661 | $ 29,608 |

The Company has identified the following obligations which were not recognized at December 31, 2008:

- a legal obligation under 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;
- 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;
- 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;
- a legal obligation under Washington state 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
- 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.

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 were to become exercisable only if a person or group acquired 10.0% 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 10.0% or more of the outstanding common stock. Each Right entitled 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 $65.00, subject to adjustments. The Rights terminated on February 6, 2009 in connection with the merger.

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 Mortgage Indentures. Under the most restrictive covenants of PSE, earnings reinvested in the business unrestricted as to payment of cash dividends were approximately $498.5 million at December 31, 2008. For the years 2008, 2007 and 2006, 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 $145.8 million, $108.4 million and $109.8 million for 2008, 2007 and 2006, respectively.

Beginning February 6, 2009, as approved in the Washington Commission merger order, Puget Energy may not declare or make a distribution unless on such date Puget Energy's ratio consolidated Earnings Before Interest, Tax, Depreciation and Amortization (EBITDA) to consolidated interest expense for the most recent ended four fiscal quarter periods prior to such date is equal or greater than two to one. Also beginning on February 6, 2009, as approved in the Washington Commission merger order, PSE dividends may not be declared or paid if its common equity ratio is 44.0% or below except to the extent a lower equity ratio is ordered by the Washington Commission. In addition, PSE cannot declare or make any distribution on the date of distribution if either: (a) the ratio of PSE's EBITDA to PSE interest for the most recent ended four fiscal quarter periods prior to such date is equal or greater than three to one; or (b) PSE's corporate credit/issuer rating is at least BBB- with Standard & Poor's and Baa3 with Moody's.

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, 2008, there were 22,689 shares of the 4.70% Series and 6,471 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 (the Redemption Price). On February 5, 2009, PSE deposited with its Redemption and Paying Agent approximately $2.0 million to defease the preferred stock and issued an irrevocable notice that the shares are to be redeemed on March 13, 2009. The Redemption and Paying Agent will pay shareholders the Redemption Price plus accrued dividends through March 13, 2009.

NOTE 8. *Long-Term Debt*

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

| SERIES | DUE | 2008 | 2007 | SERIES | DUE | 2008 | 2007 |
|---|---|---|---|---|---|---|---|
| 3.363% | 2008 | $ -- | $ 150,000 | 5.197% | 2015 | $ 150,000 | $ 150,000 |
| 6.51% | 2008 | -- | 1,000 | 7.35% | 2015 | 10,000 | 10,000 |
| 6.53% | 2008 | -- | 3,500 | 7.36% | 2015 | 2,000 | 2,000 |
| 7.61% | 2008 | -- | 25,000 | 6.74% | 2018 | 200,000 | 200,000 |
| 6.46% | 2009 | 150,000 | 150,000 | 9.57% | 2020 | 25,000 | 25,000 |
| 6.61% | 2009 | 3,000 | 3,000 | 7.15% | 2025 | 15,000 | 15,000 |
| 6.62% | 2009 | 5,000 | 5,000 | 7.20% | 2025 | 2,000 | 2,000 |
| 7.12% | 2010 | 7,000 | 7,000 | 7.02% | 2027 | 300,000 | 300,000 |
| 7.96% | 2010 | 225,000 | 225,000 | 7.00% | 2029 | 100,000 | 100,000 |
| 7.69% | 2011 | 260,000 | 260,000 | 5.483% | 2035 | 250,000 | 250,000 |
| 6.83% | 2013 | 3,000 | 3,000 | 6.724% | 2036 | 250,000 | 250,000 |
| 6.90% | 2013 | 10,000 | 10,000 | 6.274% | 2037 | 300,000 | 300,000 |
| | | | | 6.974% | 2067 | 250,000 | 250,000 |
| | | | | | Total | $ 2,517,000 | $ 2,696,500 |

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. In connection with the closing of the merger, all shelf registration statements of Puget Energy were terminated. The shelf registration of PSE was amended and provides for the offering of senior notes of PSE, secured by first mortgage bonds and unsecured debentures of PSE. The PSE registration statement is valid for three years from the date of the original filing, or until March 16, 2009 and does not specify the amount of securities that PSE may offer.

On June 1, 2007, PSE redeemed the remaining 8.231% Capital Trust Preferred Securities (classified on the balance sheet as Junior Subordinated Debentures of the Corporation Payable to a Subsidiary Trust Holding Mandatorily Redeemable Preferred Securities and referred to herein as Securities). The purpose of the redemption was to help reduce interest costs by retiring higher cost debt. The remaining $37.8 million of the Securities outstanding were redeemed on June 1, 2007 at a 4.12% premium, or $39.3 million, plus accrued interest on the redemption date.

On June 4, 2007, PSE issued $250.0 million of Junior Subordinated Notes (Notes) due June 2067. The Notes bear a fixed rate of interest for the first ten and a half years with interest payable semiannually in May and November of each year, after which the notes will bear a variable rate of interest (3-month London Interbank Offered Rate (LIBOR) plus 2.35%). Proceeds were used to fund the redemption of the remaining $37.8 million 8.231% Securities and to repay short-term debt.

The Notes are structured to be treated as debt by the Internal Revenue Service (IRS), yet they are considered to be similar to equity by the credit rating agencies. In addition, the Notes contain a call option feature and are callable in whole or in part by PSE on or after June 1, 2017. They are presented on the balance sheet as a separate line item in redeemable securities and long-term debt.

On January 23, 2009, PSE issued $250.0 million of first mortgage bonds. The bonds were placed with approximately 35 institutional investors, have a term of seven years and carry a 6.75% coupon. Net proceeds from the issue were used primarily to repay outstanding short-term debt incurred to partially fund the utility's capital expenditures, including the $240.0 million Mint Farm Power Generating Facility (Mint Farm), a natural gas-fired power plant in Longview, Washington purchased by PSE in December 2008 using short term debt financing.

Substantially all utility properties owned by the Company are subject to the lien of the Company's electric and natural 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, 2008, 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 | 2008 | 2007 |
|---|---|---|---|
| 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) | 2009 | 2010 | 2011 | 2012 | 2013 | THEREAFTER |
|---|---|---|---|---|---|---|
| Maturities of: | | | | | | |
| Long-term debt | $ 158,000 | $ 232,000 | $ 260,000 | $ -- | $ 13,000 | $ 2,015,860 |

NOTE 9. *Related Party Transactions*

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. (PSE Funding), a PSE subsidiary, which is the LIBOR plus a marginal rate. At December 31, 2008 and December 31, 2007, the outstanding balance of the Note was $26.1 million and $15.8 million, respectively and the interest rate was 1.7% and 5.31%, respectively. The outstanding balance and the related interest under the Note are eliminated by Puget Energy upon consolidation of PSE's financial statements. The $30.0 million credit facility with Puget Energy was unaffected by the merger.

The Company has a general liability claim from AEGIS Insurance Services Inc. (AEGIS) for $5.7 million as of December 31, 2008 of which $3.6 million was received as a partial payment in January 2009. One nonemployee director of Puget Energy and PSE also serves on the board of AEGIS and a PSE management employee serves on one of AEGIS' risk management committees.

PSE has property insurance with various companies and approximately 35.0% of the property insurance coverage is with American International Group, Inc (AIG). On October 23, 2008, AIG named the wife of Puget Energy's and PSE's President and Chief Executive Officer as its Vice Chairman and Chief Restructuring Officer.

NOTE 10. *Liquidity Facilities and Other Financing Arrangements*

As of December 31, 2008, and 2007, the Company had $964.7 million and $260.5 million in short-term debt outstanding with a weighted average interest rate of 3.87% and 5.97%, respectively. As of December 31 2008, the Company had four committed credit facilities that provided, in aggregate, $1.4 billion in short-term borrowing capability. Those included a $500.0 million unsecured revolving credit agreement, a $200.0 million accounts receivable securitization facility, a $375.0 million unsecured short-term credit facility and a $350.0 million unsecured credit agreement to support hedging activity. Effective with the merger on February 6, 2009, the existing credit agreements were replaced with three new credit facilities as described below.

**PSE Credit Agreements at December 31, 2008**

At December 31, 2008, PSE had available unsecured revolving credit agreements in the amounts of $500.0 million and $350.0 million, each expiring in April 2012. The credit agreements provide credit support for letters of credit and commercial paper. Lehman Brothers Bank, FSB (Lehman) committed $35.0 million to each of these facilities. In September 2008, a large Japanese bank acquired $25.0 million of Lehman's commitment to the $500.0 million facility. Consequently, at September 2008, Lehman had commitments of $10.0 million and $35.0 million under PSE's $500.0 million and $350.0 million facilities, respectively. In September 2008, Lehman informed PSE that it had suspended funding borrowing requests for its portion of these facilities. The impact of the suspension was to effectively reduce the size of these facilities to $490.0 million and $315.0 million, respectively.

At December 31, 2008, PSE had $6.6 million outstanding under a letter of credit and $431.7 million drawn on the $500.0 million facility, effectively reducing the available borrowing capacity to $51.7 million. There was no commercial paper outstanding.

At December 31, 2008, PSE had a $20.0 million letter of credit outstanding under the $350.0 million facility and no draws, effectively reducing the available borrowing capacity to $295.0 million,

In August 2008, PSE entered into a nine-month, $375.0 million credit agreement with four banks and as of December 31, 2008, PSE had fully drawn the $375.0 million capacity under the agreement.

At December 31, 2008, PSE had available a $200.0 million receivables securitization facility that expires in December 2010. $158.0 million was outstanding under the receivables securitization facility at December 31, 2008 thus leaving $42.0 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.

On February 6, 2009, the credit agreements and securitization facility described above were terminated and replaced with new facilities as a result of the merger of Puget Energy with Puget Holdings LLC (Puget Holdings).

**PSE Credit Agreements at February 6, 2009**

Effective with the merger of Puget Energy and Puget Holdings, the Company has three committed unsecured revolving credit facilities that provide, in the aggregate, $1.150 billion in short-term borrowing capability. These new facilities include a $400.0 million credit agreement for working capital needs, a $400.0 million credit facility for funding capital expenditures and a $350.0 million facility to support energy hedging activities.

These facilities mature in 2014, contain similar terms and conditions, and are syndicated among numerous committed banks. The agreements provide PSE with the ability to borrow at different interest rate options and include variable fee levels. The bank credit agreements allow the Company to borrow at the bank's prime rate or to make floating rate advances at LIBOR plus a spread that is based upon the Company's credit rating. The $400.0 million working capital facility and $350.0 million credit agreement to support energy hedging allow for issuing standby letters of credit up to the entire amount of the credit agreements. The $400.0 million working capital facility also serves as a backstop for the Company's commercial paper program.

At the close of the merger on February 6, 2009, PSE had borrowed $70.0 million on the $400.0 million working capital facility and had a $30.0 million letter of credit outstanding under the $350.0 million facility supporting energy hedging. Outside of the credit agreements, PSE had a $6.6 million letter of credit through a bank in support of a long-term transmission contract.

**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 receivables securitization facility of PSE Funding, a PSE subsidiary. Absent such borrowings, interest is charged at a base rate. At December 31, 2008, the outstanding balance of the Note was $26.1 million. The outstanding balance and the related interest under the Note are eliminated by Puget Energy upon consolidation of PSE's financial statements. This note is unaffected by the February 6, 2006 merger.

**PUGET ENERGY CREDIT FACILITIES**

As of December 31, 2008, Puget Energy had no short-term credit facilities. Effective with the close of the merger on February 6, 2009, Puget Energy has a $1.225 billion five year term loan and a $1.0 billion credit facility for funding capital expenditures.

These facilities mature in 2014, contain similar terms and conditions, and are syndicated among numerous committed banks. The agreements provide Puget Energy with the ability to borrow at different interest rate options and include variable fee levels. Borrowings may be at the bank's prime rate or at floating rates based on LIBOR plus a spread that is based upon the Puget Energy's credit rating.

As of February 6, 2009, the term loan was fully drawn and $258.0 million was outstanding under the $1.0 billion facility.

| (DOLLARS IN THOUSANDS)<br>AT DECEMBER 31 | 2008 [6] | 2007 |
|---|---|---|
| Committed financing arrangements: | | |
| PSE line of credit [1] | $490,000 | $ 500,000 |
| PSE line of credit [2] | 315,000 | 350,000 |
| PSE line of credit [3] | 375,000 | -- |
| PSE receivables securitization program [4] | 200,000 | 200,000 |
| Uncommitted financing agreements: | | |
| Puget Energy Demand Promissory Note [5] | 30,000 | 30,000 |

1 *Provided liquidity for PSE's general corporate purposes and support for PSE's outstanding commercial paper and letters of credit. At December 31, 2008, PSE had $431.7 million of loans and $6.6 million of letters of credit outstanding under this facility leaving $51.7 million of available borrowing capacity. At December 31, 2007, PSE had $108.5 million of commercial paper and $7.4 million of letters of credit outstanding under this facility leaving $384.1 million of available borrowing capacity. This credit facility was repaid and subsequently terminated in connection with the merger.*

2 *Provided credit support for PSE's energy and natural gas hedging activities. At December 31, 2008, PSE had one outstanding letter of credit under this facility in the amount of $20.0 million. There were no loans outstanding at December 31, 2008. There were no loans or letters of credit outstanding under this facility at December 31, 2007. This credit facility was repaid and subsequently terminated in connection with the merger.*

3 *Provided short term funding for PSE's acquisition of the Mint Farm natural gas fired electric generating facility and general corporate liquidity. At December 31, 2008, there were $375.0 million of loans outstanding under this facility. This credit facility was repaid and subsequently terminated in connection with the merger.*

4 *Provided borrowings secured by accounts receivable and unbilled revenues. At December 31, 2008, PSE Funding had borrowed $158.0 million, leaving $42.0 million available to borrow under the program. At December 31, 2007, PSE Funding had $152.0 million of loans secured by accounts receivable pledged as collateral under the accounts receivable securitization program. This credit facility was repaid and subsequently terminated in connection with the merger.*

5 *PSE has a revolving credit facility with Puget Energy in the form of a promissory note to borrow up to $30.0 million subject to approval by Puget Energy. At December 31, 2008, the outstanding balance on the note was $26.1 million. The outstanding balance and related interest are eliminated on Puget Energy's balance sheet upon consolidation.*

6 *Effective February 6, 2009, the PSE lines of credit and PSE receivables securitization program were terminated and replaced with three lines of credit with a group of banks. The three new lines of credit are for $400.0 million to fund operating expenses, $400.0 million to fund capital expenditures and $350.0 million to support energy and natural gas hedging activity.*

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, 2008 and 2007.

| | 2008 | | 2007 | |
|---|---|---|---|---|
| (DOLLARS IN MILLIONS) | CARRYING AMOUNT | FAIR VALUE | CARRYING AMOUNT | FAIR VALUE |
| Financial assets: | | | | |
| Cash | $ 38.5 | $ 38.5 | $ 40.8 | $ 40.8 |
| Restricted cash | 18.9 | 18.9 | 4.8 | 4.8 |
| Equity securities | 1.0 | 1.0 | 1.5 | 1.5 |
| Notes receivable and other | 71.8 | 71.8 | 70.2 | 70.2 |
| Energy derivatives | 22.3 | 22.3 | 29.0 | 29.0 |
| Long-term restricted cash | -- | -- | -- | -- |
| Financial liabilities: | | | | |
| Short-term debt | $ 964.7 | $ 964.7 | $ 260.5 | $ 260.5 |
| Short-term debt owed by PSE to Puget Energy[1] | 26.1 | 26.1 | 15.8 | 15.8 |
| Preferred stock subject to mandatory redemption | 1.9 | 1.9 | 1.9 | 1.2 |
| Junior subordinated notes | 250.0 | 112.5 | 250.0 | 215.1 |
| Long-term debt – fixed-rate[2] | 2,678.9 | 2,109.0 | 2,858.4 | 2,623.2 |
| Energy derivatives | 395.3 | 395.3 | 27.0 | 27.0 |

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 2008 and 2007.*

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 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. On February 2, 2009, PSE purchased the two 74 megawatt (MW) combustion turbine generators for $22.6 million. In accordance with SFAS No. 71, 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 2008 was $0.4 million and capital lease amortization was $0.6 million for 2008. Certain leases contain purchase options and renewal and escalation provisions. Rent expense net of sublease receipts were:

| (DOLLARS IN THOUSANDS) AT DECEMBER 31 | |
|---|---|
| 2008 | $ 29,087 |
| 2007 | 27,012 |
| 2006 | 24,184 |

Payments received for the subleases of properties were approximately $0.1 million, $0.1 million and $0.1 million for 2008, 2007 and 2006, respectively.

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

| (DOLLARS IN THOUSANDS) AT DECEMBER 31 | OPERATING | CAPITAL |
|---|---|---|
| 2009 | $ 15,471 | $ 70,703 |
| 2010 | 13,465 | -- |
| 2011 | 13,155 | -- |
| 2012 | 12,292 | -- |
| 2013 | 12,075 | -- |
| Thereafter | 74,361 | -- |
| Total minimum lease payments | $140,819 | $ 70,703 |

PSE leases a portion of its owned natural 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 | 2009 |
|---|---|
| Lease receipts | $ 886 |

NOTE 13. *Income Taxes*

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

| PUGET ENERGY (DOLLARS IN THOUSANDS) | 2008 | 2007 | 2006 |
|---|---|---|---|
| Charged to operating expense: | | | |
| Current: | | | |
| Federal | $ (16,625) | $ 3,238 | $ 57,526 |
| State | (85) | (189) | 979 |
| Deferred - federal | 76,616 | 69,533 | 33,982 |
| Total income taxes before cumulative effect of accounting change | 59,906 | 72,582 | 92,487 |
| Cumulative effect of accounting change | -- | -- | 48 |
| Total income taxes from continuing operations | $ 59,906 | $ 72,582 | $ 92,535 |

| PUGET SOUND ENERGY (DOLLARS IN THOUSANDS) | 2008 | 2007 | 2006 |
|---|---|---|---|
| Charged to operating expense: | | | |
| Current: | | | |
| Federal | $ (13,103) | $ 5,555 | $ 63,475 |
| State | (85) | (189) | 979 |
| Deferred - federal | 74,070 | 68,815 | 34,235 |
| Total income taxes before cumulative effect of accounting change | 60,882 | 74,181 | 98,689 |
| Cumulative effect of accounting change | -- | -- | 48 |
| Total income taxes from continuing operations | $ 60,882 | $ 74,181 | $ 98,737 |

The following reconciliation compares pre-tax book income at the federal statutory rate of 35.0% to the actual income tax expense in the Consolidated Statements of Income:

| PUGET ENERGY<br>(DOLLARS IN THOUSANDS) | 2008 | 2007 | 2006 |
|---|---|---|---|
| Income taxes at the statutory rate | $ 75,069 | $ 89,966 | $ 90,947 |
| Increase (decrease): | | | |
| Utility plant differences | 5,882 | 6,032 | 9,307 |
| AFUDC excluded from taxable income | (4,670) | (5,055) | (7,987) |
| Capitalized interest | 3,653 | 3,649 | 5,806 |
| Production tax credit | (23,112) | (20,154) | (7,019) |
| Other - net | 3,084 | (1,856) | 1,481 |
| Total income taxes | $ 59,906 | $ 72,582 | $ 92,535 |
| Effective tax rate | 27.9% | 28.2% | 35.6% |

| PUGET SOUND ENERGY<br>(DOLLARS IN THOUSANDS) | 2008 | 2007 | 2006 |
|---|---|---|---|
| Income taxes at the statutory rate | $ 78,266 | $ 92,858 | $ 96,417 |
| Increase (decrease): | | | |
| Utility plant differences | 5,882 | 6,032 | 9,307 |
| AFUDC excluded from taxable income | (4,670) | (5,055) | (7,987) |
| Capitalized interest | 3,653 | 3,649 | 5,806 |
| Production tax credit | (23,112) | (20,154) | (7,019) |
| Other - net | 863 | (3,149) | 2,213 |
| Total income taxes | $ 60,882 | $ 74,181 | $ 98,737 |
| Effective tax rate | 27.2% | 28.0% | 35.8% |

The Company's deferred tax liability at December 31, 2008 and 2007 is composed of amounts related to the following types of temporary differences:

| PUGET ENERGY<br>(DOLLARS IN THOUSANDS) | 2008 | 2007 |
|---|---|---|
| Utility plant and equipment | $ 746,486 | $ 642,169 |
| Regulatory asset for income taxes | 95,417 | 104,928 |
| Storm damage | 42,037 | 44,571 |
| Other deferred tax liabilities | 47,963 | 62,395 |
| Subtotal deferred tax liabilities | 931,903 | 854,063 |
| Pensions and other compensation | (62,837) | 9,852 |
| Fair value of derivative instruments | (69,259) | (1,612) |
| Other deferred tax assets | (59,480) | (48,153) |
| Subtotal deferred tax assets | (191,576) | (39,913) |
| Total | $ 740,327 | $ 814,150 |

| PUGET SOUND ENERGY<br>(DOLLARS IN THOUSANDS) | 2008 | 2007 |
|---|---|---|
| Utility plant and equipment | $ 746,486 | $ 717,661 |
| Regulatory asset for income taxes | 95,417 | 104,928 |
| Storm damage | 42,037 | 44,571 |
| Other deferred tax liabilities | 48,637 | 65,616 |
| Subtotal deferred tax liabilities | 932,577 | 932,776 |
| Pensions and other compensation | (62,837) | (75,492) |
| Fair value of derivative instruments | (69,259) | |
| Other deferred tax assets | (59,480) | (39,913) |
| Subtotal deferred tax assets | (191,576) | (115,405) |
| Total | $ 741,001 | $ 817,371 |

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

| PUGET ENERGY (DOLLARS IN THOUSANDS) | 2008 | 2007 |
|---|---|---|
| Current deferred taxes | $ (9,439) | $ (4,011) |
| Non-current deferred taxes | 749,766 | 818,161 |
| Total | $ 740,327 | $ 814,150 |

| PUGET SOUND ENERGY (DOLLARS IN THOUSANDS) | 2008 | 2007 |
|---|---|---|
| Current deferred taxes | $ (9,439) | $ (4,011) |
| Non-current deferred taxes | 750,440 | 821,382 |
| Total | $ 741,001 | $ 817,371 |

The Company calculates its deferred tax assets and liabilities under SFAS No. 109. 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. PSE has established a regulatory asset for income taxes recoverable through future rates related to those temporary differences for which no deferred taxes have been provided, based on prior and expected future ratemaking treatment.

The Company accounts for uncertain tax position under FIN 48, which clarifies the accounting for uncertainty in income taxes recognized in the financial statements in accordance with SFAS No. 109. 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. As of the date of adoption, the Company had no material unrecognized tax benefits. As of December 31, 2008, the Company had no material unrecognized tax benefits. As a result, no interest or penalties were accrued for unrecognized tax benefits during the year.

For FIN 48 purposes, the Company has open tax years from 2006 through 2008. The Company classifies interest as interest expense and penalties as other expense in the financial statements.

IRS AUDIT

The Company's tax returns are routinely audited by federal, state and city tax authorities. In May 2006, the IRS completed its examination of the Company's 2001, 2002 and 2003 federal income tax returns. In June 2008, the IRS completed its examination of the Company's 2004 and 2005 federal income tax returns. The Company formally appealed the IRS audit adjustment relating 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.

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.

During 2007, the IRS national office established settlement guidelines which the appeals office uses in reaching settlements with taxpayers. The effect of the settlement guidelines shift some of the benefits claimed in 2001 through 2004 into 2005 and 2006. As a result, through 2008, the Company accrued interest in the amount of $7.0 million.

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. On November 5, 2008, PSE filed an accounting petition for a Washington Commission order authorizing the deferral and recovery of interest due the IRS for tax years 2001 to 2006 along with carrying costs incurred in connection with the interest due.

In its 2003 tax return, the Company claimed a deduction for a portion of the California Independent System Operator (CAISO) receivable. Upon examination, the IRS claimed that the deduction was not valid for the 2003 tax year. The Company formally appealed. In appeals, the Company and the IRS agreed to move the deduction from 2003 to 2005. This resulted in a net interest charge of $1.4 million.

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). 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 following table illustrates the effect of applying SFAS No. 158 in 2006, the year of initial adoption by the Company:

| | Before Application of Statement 158 | | Adjustments | | After Application of Statement 158 | |
|---|---|---|---|---|---|---|
| (Dollars in Thousands) | Pension Plan | Other Benefits | Pension Plan | Other Benefits | Pension Plan | Other Benefits |
| **Transition Adjustments for Statement of Financial Position:** | | | | | | |
| Prepaid benefit cost | $ 122,274 | $ -- | $ (122,274) | $ -- | $ -- | $ -- |
| Accrued benefit (liability) | -- | (12,309) | -- | 12,309 | -- | -- |
| Intangible asset | -- | -- | -- | -- | -- | -- |
| Accumulated other comprehensive income, (pre-tax) | -- | -- | -- | -- | -- | -- |
| Noncurrent asset | -- | -- | 101,708 | -- | 101,708 | -- |
| Current liability | -- | -- | -- | (50) | -- | (50) |
| Noncurrent liability | -- | -- | -- | (11,309) | -- | (11,309) |
| Total | $ 122,274 | $ (12,309) | $ (20,566 ) | $ 950 | $ 101,708 | $ (11,359) |

The following table represents the effect of applying SFAS No. 158 on the Supplemental Executive Retirement Plan (SERP) plan:

| | Before Application of Statement 158 | Adjustments | After Application of Statement 158 |
|---|---|---|---|
| (Dollars in Thousands) | SERP | SERP | SERP |
| **Transition Adjustments for Statement of Financial Position:** | | | |
| Prepaid benefit cost | $ -- | $ -- | $ -- |
| Accrued benefit (liability) | (33,056) | 33,056 | -- |
| Intangible asset | 4,027 | (4,027) | -- |
| Accumulated other comprehensive income, (pre-tax) | 6,789 | (6,789) | -- |
| Noncurrent asset | -- | -- | -- |
| Current liability | -- | (4,533) | (4,533) |
| Noncurrent liability | -- | (33,577) | (33,577) |
| Total | $ (22,240) | $ (15,870) | $(38,110) |

The Company has a defined benefit pension plan covering substantially all PSE employees, with a cash balance feature for all but International Brotherhood of Electrical Workers Union (IBEW) represented employees. Benefits are a function of age, salary and service. The Company also maintains a non-qualified SERP for certain of its senior management 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.

| (Dollars in Thousands) | Qualified Pension Benefits 2008 | Qualified Pension Benefits 2007 | SERP Pension Benefits 2008 | SERP Pension Benefits 2007 | Other Benefits 2008 | Other Benefits 2007 |
|---|---|---|---|---|---|---|
| **Change in benefit obligation:** | | | | | | |
| Benefit obligation at beginning of year | $ 426,253 | $ 430,900 | $ 37,111 | $ 38,110 | $ 18,864 | $ 27,207 |
| Service cost | 12,750 | 12,385 | 935 | 926 | 127 | 269 |
| Interest cost | 26,685 | 24,434 | 2,211 | 2,079 | 1,130 | 1,249 |
| Mergers, sales and closures | -- | -- | -- | -- | -- | (2,648 ) |
| Amendment | 5,324 [2] | -- | -- | -- | -- | (306 ) [1] |
| Actuarial loss (gain) | 11,804 | (14,943 ) | 616 | (1,678 ) | 90 | (3,723 ) |
| Benefits paid | (22,230 ) | (26,523 ) | (1,525 ) | (2,326 ) | (2,123 ) | (3,184 ) |
| Benefit obligation at end of year | $ 460,586 | $ 426,253 | $ 39,348 | $ 37,111 | $ 18,088 | $ 18,864 |

[1] *The Company has an amendment related to changes in eligibility criteria. On June 20, 2007, the IBEW ratified a collective bargaining agreement with PSE. The collective bargaining agreement included changes to the Company's subsidy for retiree medical insurance. Effective June 20, 2007, IBEW-represented employees hired after June 20, 2002 will not receive a retiree medical subsidy at retirement.*

[2] *On August 27, 2008, the Plan was amended, effective October 1, 2008, increasing the benefits for participants whose monthly benefit payments commenced on or before January 1, 1999. The amendment resulted in a one-time increase in benefits by 1.0% for each year of retirement prior to 1999, subject to a maximum increase of 15.0%.*

| (Dollars in Thousands) | Qualified Pension Benefits 2008 | Qualified Pension Benefits 2007 | SERP Pension Benefits 2008 | SERP Pension Benefits 2007 | Other Benefits 2008 | Other Benefits 2007 |
|---|---|---|---|---|---|---|
| **Change in plan assets:** | | | | | | |
| Fair value of plan assets at beginning of year | $ 558,529 | $ 532,608 | $ -- | $ -- | $ 14,700 | $ 15,847 |
| Actual return on plan assets | (168,299 ) | 52,444 | -- | -- | (4,218 ) | 499 |
| Employer contribution | 24,900 | -- | 1,525 | 2,326 | 76 | 1,538 |
| Benefits paid | (22,230 ) | (26,523 ) | (1,525 ) | (2,326 ) | (2,123 ) | (3,184 ) |
| Fair value of plan assets at end of year | $ 392,900 | $ 558,529 | $ -- | $ -- | $ 8,435 | $ 14,700 |
| Funded status at end of year | $ (67,686 ) | $ 132,276 | $ (39,348 ) | $ (37,111 ) | $ (9,653 ) | $ (4,164 ) |

| (Dollars in Thousands) | Qualified Pension Benefits 2008 | Qualified Pension Benefits 2007 | SERP Pension Benefits 2008 | SERP Pension Benefits 2007 | Other Benefits 2008 | Other Benefits 2007 |
|---|---|---|---|---|---|---|
| **Amounts recognized in Statement of Financial Position consist of:** | | | | | | |
| Noncurrent assets | $ -- | $ 132,276 | $ -- | $ -- | $ -- | $ -- |
| Current liabilities | -- | -- | (4,027 ) | (4,029 ) | (58 ) | (49 ) |
| Noncurrent liabilities | (67,686 ) | -- | (35,321 ) | (33,082 ) | (9,595 ) | (4,115 ) |
| Total | $ (67,686 ) | $ 132,276 | $ (39,348 ) | $ (37,111 ) | $ (9,653 ) | $ (4,164 ) |
| **Amounts recognized in Accumulated Other Comprehensive Income consist of:** | | | | | | |
| Net loss (gain) | $ 206,134 | $ (14,578 ) | $ 9,055 | $ 9,171 | $ (2,948 ) | $ (8,445 ) |
| Prior service cost | 6,304 | 1,747 | 2,046 | 2,662 | 350 | 433 |
| Transition obligations | -- | -- | -- | -- | 200 | 250 |
| Total | $ 212,438 | $ (12,831 ) | $ 11,101 | $ 11,833 | $ (2,398 ) | $ (7,762 ) |

| (DOLLARS IN THOUSANDS) | QUALIFIED PENSION BENEFITS 2008 | 2007 | 2006 | SERP PENSION BENEFITS 2008 | 2007 | 2006 | OTHER BENEFITS 2008 | 2007 | 2006 |
|---|---|---|---|---|---|---|---|---|---|
| **Components of net periodic benefit cost:** | | | | | | | | | |
| Service cost | $ 12,750 | $ 12,385 | $ 11,367 | $ 935 | $ 926 | $ 1,186 | $ 128 | $ 269 | $ 361 |
| Interest cost | 26,685 | 24,433 | 22,536 | 2,211 | 2,079 | 2,131 | 1,130 | 1,250 | 1,522 |
| Expected return on plan assets | (41,555 ) | (38,859 ) | (37,572 ) | -- | -- | -- | (789 ) | (826 ) | (871 ) |
| Amortization of prior service cost | 768 | 677 | 680 | 616 | 1,365 | 1,661 | 84 | 353 | 534 |
| Amortization of net loss (gain) | 945 | 4,193 | 4,032 | 732 | 994 | 1,198 | (799 ) | (834 ) | (273 ) |
| Amortization of transition obligation | -- | -- | -- | -- | -- | | 50 | 234 | 418 |
| Net periodic benefit cost (income) | $ (407 ) | $ 2,829 | $ 1,043 | $ 4,494 | $ 5,364 | $ 6,176 | $ (196 ) | $ 446 | $ 1,691 |
| Curtailment/settlement cost [1] | $ -- | $ -- | $ -- | $ -- | $ -- | $ -- | $ -- | $ 708 | $ -- |

1 *As part of the June 20, 2007 settlement, IBEW-represented employees with less than five years of service would no longer receive a medical subsidy at retirement and those employees with more than one year of service but less than five years of service received a one-time cash payment. Current IBEW-represented employees with five or more years of service had a one-time opportunity to elect a cash payment that varied depending on the years of employment with PSE in lieu of continuing eligibility for the retiree medical subsidy. As a result of the termination, the curtailment loss was $0.7 million.*

| (DOLLARS IN THOUSANDS) | QUALIFIED PENSION BENEFITS 2008 | 2007 | SERP PENSION BENEFITS 2008 | 2007 | OTHER BENEFITS 2008 | 2007 |
|---|---|---|---|---|---|---|
| **Other changes (pre-tax) in plan assets and benefit obligations recognized in other comprehensive income:** | | | | | | |
| Net loss (gain) | $ 221,657 | $ (28,527 ) | $ 615 | $ (1,678 ) | $ 4,698 | $ (3,396 ) |
| Amortization of net loss (gain) | (945 ) | (4,193 ) | (731 ) | (994 ) | 799 | 835 |
| Mergers, sales and closures | -- | -- | -- | -- | -- | (3,356 ) |
| Prior service cost (credit) | 5,325 | -- | -- | -- | -- | (307 ) |
| Amortization of prior service cost | (768 ) | (678 ) | (616 ) | (1,365 ) | (84 ) | (353 ) |
| Amortization of transition (asset) obligation | -- | -- | -- | -- | (50 ) | (234 ) |
| Total change in other comprehensive income for year | $ 225,269 | $ (33,398 ) | $ (732 ) | $ (4,037 ) | $ 5,363 | $ (6,811 ) |

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 2009 are $3.2 million and $1.1 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 2009 are $(0.2) million, $0.1 million and less than $0.1 million, respectively. The estimated net loss (gain) and prior service cost (credit) for the SERP that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2009 are $0.9 million and $0.6 million, respectively.

ASSUMPTIONS

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

| | Qualified Pension Benefits | | | SERP Pension Benefits | | | Other Benefits | | |
|---|---|---|---|---|---|---|---|---|---|
| **Benefit Obligation Assumptions** | 2008 | 2007 | 2006 | 2008 | 2007 | 2006 | 2008 | 2007 | 2006 |
| Discount rate | 6.20% | 6.30% | 5.80% | 6.20% | 6.30% | 5.80% | 6.20% | 6.30% | 5.80% |
| Rate of compensation increase | 4.50% | 4.50% | 4.50% | 4.50% | 4.50% | 4.50% | 4.50% | -- | -- |
| Medical trend rate | -- | -- | -- | -- | -- | -- | 8.00% | 9.00% | 10.00% |

| | Qualified Pension Benefits | | | SERP Pension Benefits | | | Other Benefits | | |
|---|---|---|---|---|---|---|---|---|---|
| **Benefit Cost Assumptions** | 2008 | 2007 | 2006 | 2008 | 2007 | 2006 | 2008 | 2007 | 2006 |
| Discount rate | 6.30% | 5.80% | 5.60% | 6.30% | 5.80% | 5.60% | 6.30% | 5.80% | 5.60% |
| Rate of plan assets | 8.25% | 8.25% | 8.25% | -- | -- | 8.25% | -- | 3.9-8% | 4.3-8% |
| Rate of compensation increase | 4.50% | 4.50% | 4.50% | 4.50% | 4.50% | 4.50% | 4.50% | -- | -- |
| Medical trend rate | -- | -- | -- | -- | -- | -- | 9.00% | 10.00% | 11.00% |

The assumed medical inflation rate used to determine benefit obligations is 8.0% in 2009 grading down to 7.0% in 2010. A 1.0% change in the assumed medical inflation rate would have the following effects:

| | 2008 | | 2007 | |
|---|---|---|---|---|
| (Dollars in Thousands) | 1% Increase | 1% Decrease | 1% Increase | 1% Decrease |
| Effect on post-retirement benefit obligation | $ 184 | $ (171) | $ 216 | $ (189) |
| Effect on service and interest cost components | 12 | (11) | 16 | (15) |

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. 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 SERP and the other postretirement plans for the year ending December 31, 2009 are $4.0 million and $0.1 million respectively. The full amount of the pension funding for 2009 is for the Company's non-qualified supplemental retirement plan.

PLAN ASSETS

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

| | 2008 | | 2007 | |
|---|---|---|---|---|
| | PENSION BENEFITS | OTHER BENEFITS | PENSION BENEFITS | OTHER BENEFITS |
| Short-term investments and cash | 2.80% | 1.4% | 2.08% | -- |
| Equity securities | 39.04% | -- | 54.83% | -- |
| Fixed income securities | 11.83% | 13.1% | 15.07% | 12.3% |
| Mutual funds (equity and fixed income) | 46.33% | 85.5% | 28.02% | 87.7% |

The Company has a Retirement Plan 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 Plan Committee prior to being implemented.

The Retirement Plan Committee invests trust assets 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 Plan Committee has established investment allocation percentages by asset classes as follows:

| | ALLOCATION | | |
|---|---|---|---|
| ASSET CLASS | MINIMUM | TARGET | MAXIMUM |
| Equity securities | 35% | 62% | 85% |
| Fund of Hedge Funds | 5% | 10% | 15% |
| Tactical Asset Allocation | -- | 5% | 10% |
| Fixed-income securities | 15% | 23% | 30% |
| Real estate and cash | -- | -- | 15% |

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

| (DOLLARS IN THOUSANDS) | 2009 | 2010 | 2011 | 2012 | 2013 | 2014-2018 |
|---|---|---|---|---|---|---|
| Total benefits | $ 30,200 | $ 31,500 | $ 32,100 | $ 33,700 | $ 35,200 | $ 189,500 |

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

| (DOLLARS IN THOUSANDS) | 2009 | 2010 | 2011 | 2012 | 2013 | 2014-2018 |
|---|---|---|---|---|---|---|
| Total benefits | $ 4,027 | $ 3,118 | $ 2,202 | $ 2,832 | $ 3,854 | $ 20,529 |

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

| (DOLLARS IN THOUSANDS) | 2009 | 2010 | 2011 | 2012 | 2013 | 2014-2018 |
|---|---|---|---|---|---|---|
| Total benefits | $ 1,788 | $ 1,767 | $ 1,693 | $ 1,616 | $ 1,542 | $ 7,053 |
| Total benefits without Medicare Part D subsidy | $ 2,217 | $ 2,201 | $ 2,162 | $ 2,119 | $ 2,060 | $ 9,268 |

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 $10.0 million, $9.0 million and $7.9 million for the years 2008, 2007 and 2006, respectively. The Employee Investment Plan eligibility requirements are set forth in the plan documents.

NOTE 16. *Stock-based Compensation Plans*

Effective January 1, 2006, the Company adopted the fair value recognition provisions of SFAS No. 123R, using the modified-prospective transition method. Under that transition method, compensation cost recognized effective 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. 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. For purposes of determining stock compensation expense under SFAS No. 123R, forfeitures for multi-year plans are calculated based on the historical average forfeiture rate for vested cycles and are trued up to actual forfeiture experience in the year of vesting.

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, was $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.

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 and 2007 cycles 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. As a result of the merger on February 6, 2009, all shares outstanding under the LTI Plan vested and were paid out in cash to plan participants. Puget Energy recorded $12.7 million as a merger expense due to the vesting of the LTI Plan shares.

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. The number of shares awarded and the amount of 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 $3.7 million, $7.9 million and $(1.6) million for 2008, 2007 and 2006, respectively. As of December 31, 2008, the Company had $2.7 million of total unrecognized compensation cost, net of forfeitures, related to nonvested performance share grants. That cost was recognized upon close of the merger. The weighted-average fair value per performance share granted for the years ended 2007 and 2006 was $24.75 and $24.77, respectively.

Performance shares activity for the twelve months ended December 31, 2008 was as follows:

| | Number of Shares | Weighted-Average Fair Value Per Share |
|---|---|---|
| Performance Shares Outstanding at December 31, 2006 includes: | 378,211 | $ 21.72 |
| Granted | 144,894 | 24.64 |
| Vested | (232,344) | 21.21 |
| Cancelled | (59) | 22.52 |
| Forfeited | (5,583) | 22.73 |
| Total at December 31, 2007: | 285,119 | $ 23.60 |
| Granted | 111,208 | 26.72 |
| Vested | (141,406) | 22.52 |
| Forfeited | (10,531) | 23.56 |
| Performance Shares Outstanding at December 31, 2008: | 244,390 | $ 25.65 |

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 portion of the performance share grants that can be paid in cash is classified and accounted for as a liability. As a result, the compensation expense of these liability awards is recognized over the performance period based on the fair value (i.e. cash value) of the award, and is periodically updated based on expected ultimate cash payout. Compensation cost recognized during the performance period for the liability portion of the performance grants is based on the closing price of the Company's common stock on the date of measurement and the number of months of service rendered during the period. 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 the LTI Plan (for a total of 300,000 non-qualified stock options) to the 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. All 300,000 options were fully vested and remained outstanding and exercisable at December 31, 2008. The fair value of the options at the grant date was $3.33 per share. The fair value of the stock option award was estimated on the date of grant using the Black-Scholes option valuation model. The options were cancelled at the time of the merger and paid in cash to the President and Chief Executive Officer per the terms of the merger agreement.

### Restricted Stock

In 2008, 2007 and 2006, the Company granted 91,115 shares, 97,244 shares and 107,555 shares, respectively, of restricted stock under the LTI Plan to be purchased on the open market or as a new issuance. Under the 2008, 2007 and 2006 grants, the shares vest 15.0% in year 1 on January 1, 25.0% vest in year 2 on January 1 and the remaining 60.0% vest in year 3 on January 1, based upon a performance and service condition.

Restricted stock activity for the twelve months ended December 31, 2008 and 2007 were as follows:

| | Number of Shares | Weighted-Average Fair Value Per Share |
|---|---|---|
| Restricted Stock Outstanding at December 31, 2006: | 205,656 | $ 22.02 |
| Granted | 97,244 | 24.72 |
| Vested | (39,083 ) | 22.27 |
| Forfeited | (3,435 ) | 23.19 |
| Restricted Stock Outstanding at December 31, 2007: | 260,382 | $ 22.98 |
| Granted | 91,115 | 26.72 |
| Vested | (117,439 ) | 22.99 |
| Forfeited | (6,415 ) | 23.21 |
| Restricted Stock Outstanding at December 31, 2008: | 227,643 | $ 24.64 |

Compensation expense related to the restricted shares was $2.4 million and $1.4 million for 2008 and 2007, 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.

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. 2,000 shares vested on January 8, 2007, 3,000 shares vested on January 8, 2008 and the remaining 5,000 shares vested on May 6, 2008.

Restricted stock units activity for the twelve months ended December 31, 2008 was as follows:

| | NUMBER OF SHARES | WEIGHTED-AVERAGE FAIR VALUE PER SHARE |
|---|---|---|
| Restricted Stock Units Outstanding at December 31, 2006: | 10,000 | $ 25.36 |
| Vested | (2,000 ) | 25.36 |
| Restricted Stock Units Outstanding at December 31, 2007: | 8,000 | $ 25.36 |
| Vested | (8,000 ) | 25.36 |
| Restricted Stock Units Outstanding at December 31, 2008: | -- | -- |

There were no restricted stock units granted or forfeited during 2008 and 2007. Compensation expense related to the restricted stock units agreement was $0.1 million for 2008 and 2007. 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 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. Retirement equivalent stock activity is as follows:

| | NUMBER OF SHARES | WEIGHTED-AVERAGE FAIR VALUE PER SHARE |
|---|---|---|
| Retirement Equivalent Stock Awarded: | | |
| 2007 | 9,476 | $ 25.36 |
| 2008 | 7,574 | $ 27.43 |

All shares vested in May 2008. Compensation expense related to the retirement equivalent stock agreement was $0.3 million, $0.1 million and $0.2 million in 2008, 2007 and 2006, respectively. All equivalent stock units are vested.

NON-EMPLOYEE DIRECTOR STOCK PLAN

Prior to February 6, 2009, when it was terminated, the Company had 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 had a term through December 31, 2015, non-employee directors received a portion of their quarterly retainer fees in Puget Energy stock except that 100.0% of quarterly retainers were paid in Puget Energy stock until the director held a number of shares equal in value to two years of their retainer fees. Directors could choose to continue to receive their entire retainer in Puget Energy stock. The compensation expense related to the director stock plan was $0.7 million and $0.6 million in 2008 and 2007, respectively. The Company issued new shares or purchased stock for this plan on the open market up to a maximum of 350,000 shares. As of December 31, 2008, 62,362 shares had been issued or purchased for the director stock plan and 121,253 deferred, for a total of 183,615 shares. As of December 31, 2007, the number of shares that had been purchased for the director stock plan was 53,173 and deferred was 101,678, for a total of 154,851 shares. The director stock plan was terminated on February 6, 2009 by action of the Board of Directors upon completion of the merger and future director payments will be paid in cash.

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 2008 and 2007.

| STOCK ISSUANCE CYCLE | 2008 | 2007 | 2006 |
|---|---|---|---|
| Performance awards | | | |
| Risk-free interest rate | * | ** | ** |
| Expected lives – years | 3.0 | 3.0 | 3.0 |
| Expected stock volatility | ** | ** | ** |
| Dividend yield | * | * | * |

* *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, as amended, 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 the Company's physical contracts qualify for the NPNS exception to derivative accounting rules, provided they meet certain criteria. Generally, NPNS applies if the Company deems the counterparty creditworthy, if the counterparty owns or controls energy resources within the western region to allow for physical delivery of the energy and if the transaction is within the Company's forecasted load requirements. The Company may enter into financial fixed contracts to hedge the variability of certain NPNS contracts. 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, for energy related derivatives due to the PCA mechanism and 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 following table presents electric derivatives that are designated as cash flow hedges or contracts that do not meet the NPNS exception at December 31, 2008 and December 31, 2007:

| | Electric Derivatives | |
|---|---|---|
| (Dollars in Millions) | December 31, 2008 | December 31, 2007 |
| Current asset | $ 0.4 | $ 11.1 |
| Long-term asset | 0.5 | 6.6 |
| Total assets | $ 0.9 | $ 17.7 |
| | | |
| Current liability | $ 90.6 | $ 9.8 |
| Long-term liability | 96.1 | -- |
| Total liabilities | $ 186.7 | $ 9.8 |

If it is determined that it is uneconomical to operate the Company's controlled electric generating facilities in the future period, the fuel supply cash flow hedge relationship is terminated and the hedge is de-designated which results in the unrealized gains and losses associated with the contracts being recorded in the income statement. As these contracts are settled, the costs are recognized as energy costs and are included as part of the PCA mechanism.

At December 31, 2007, the Company had an unrealized day one loss deferral of $9.0 million related to a three-year locational power exchange contract which was modeled and therefore the day one loss was deferred under EITF No. 02-3. The contract has economic benefit to the Company over its terms. The locational exchange will help ease electric transmission congestion across the Cascade Mountains during the winter months as the Company will take delivery of energy at a location that interconnects with the Company's transmission system in western Washington. At the same time, the Company will make available the quantities of power at the Mid-Columbia trading hub location. The day one loss deferral was transferred to retained earnings on January 1, 2008 as required by SFAS No. 157 and any future day one loss on contracts will be recorded in the income statement beginning January 1, 2008 in accordance with the statement.

The following table presents the impact of changes in the market value of derivative instruments not meeting NPNS or cash flow hedge criteria to the Company's earnings during the twelve months ending December 31, 2008 and December 31, 2007:

| (Dollars in millions) | December 31, 2008 | December 31, 2007 | Change |
|---|---|---|---|
| Increase (decrease) in earnings | $ (7.5) | $ 2.7 | $ (10.2) |

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 under SFAS No. 133 of $7.5 million for 2008 compared to an increase in earnings of $2.7 million for 2007. The decrease in earnings in 2008 primarily relates to a $6.1 million unrealized loss associated with the ineffective portion of cash flow hedges for two long-term power supply agreements.

The amount of unrealized gain (loss), net of tax, related to the Company's energy-related cash flow hedges under SFAS No. 133 consisted of the following at December 31, 2008 and December 31, 2007:

| (Dollars in Millions, net of tax) | December 31, 2008 | December 31, 2007 |
|---|---|---|
| Other comprehensive income – unrealized gain/(loss) | $ (111.7) | $ 3.4 |

The following table presents the derivative hedges of natural gas contracts to serve natural gas customers at December 31, 2008 and December 31, 2007:

| | Gas Derivatives | |
|---|---|---|
| (Dollars in millions) | December 31, 2008 | December 31, 2007 |
| Current asset | $ 15.2 | $ 6.0 |
| Long-term asset | 6.2 | 5.3 |
| Total assets | $ 21.4 | $ 11.3 |
| | | |
| Current liability | $ 146.3 | $ 17.3 |
| Long-term liability | 62.3 | -- |
| Total liabilities | $ 208.6 | $ 17.3 |

At December 31, 2008, the Company had total assets of $21.4 million and total liabilities of $208.6 million related to financial contracts used to hedge the cost of physical gas purchased 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.

The ending balance in other comprehensive income (OCI) related to the forward starting swaps and previously settled treasury lock contracts at December 31, 2008 is a net loss of $7.9 million after tax and accumulated amortization. This compares to a loss of $8.2 million in OCI after tax and accumulated amortization at December 31, 2007.

SFAS No. 161 became effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. SFAS No. 161 requires enhanced disclosures about a company's derivative activities and how the related hedged items affect a company's financial position, financial performance and cash flows. To meet the objectives, SFAS No. 161 requires qualitative disclosures about the Company's fair value amounts of gains and losses associated with derivative instruments, as well as disclosures abut credit-risk-related contingent features in derivative agreements. The Company elected to report such activities for the period ended December 31, 2008.

The following table presents the fair values and locations of derivative instruments recorded in the balance sheet at December 31, 2008:

| | Derivatives Designated as Hedging Instruments | | | |
|---|---|---|---|---|
| | Asset Derivatives | | Liability Derivatives | |
| (Dollars in Millions) At December 31, 2008 | Balance Sheet Location | Fair Value | Balance Sheet Location | Fair Value |
| Commodity contracts: | | | | |
| Electric derivatives: Current | Unrealized gain on derivative instruments | $ 0.1 | Unrealized loss on derivative instruments | $ 85.3 |
| Long term | Unrealized gain on derivative instruments | 0.4 | Unrealized loss on derivative instruments | 93.1 |
| Gas Derivatives: Current | Unrealized gain on derivative instruments | -- | Unrealized loss on derivative instruments | -- |
| Long term | Unrealized gain on derivative instruments | -- | Unrealized loss on derivative instruments | -- |
| Total derivatives designated as hedging instruments | | $ 0.5 | | $ 178.4 |

| | Derivatives Not Designated as Hedging Instruments [1] | | | |
|---|---|---|---|---|
| Commodity contracts: | | | | |
| Electric derivatives: | | | | |
| Current | Unrealized gain on derivative instruments | $ 0.3 | Unrealized loss on derivative instruments | $ 5.3 |
| Long term | Unrealized gain on derivative instruments | 0.1 | Unrealized loss on derivative instruments | 3.0 |
| Gas derivatives: | | | | |
| Current | Unrealized gain on derivative instruments | 15.2 | Unrealized loss on derivative instruments | 146.3 |
| Long term | Unrealized gain on derivative instruments | 6.2 | Unrealized loss on derivative instruments | 62.3 |
| Total derivatives not designated as hedging instruments | | $ 21.8 | | $ 216.9 |
| Combined total | | $ 22.3 | | $ 395.3 |

1 *Derivatives that did not meet NPNS or cash flow hedge criteria are classified above as Derivatives not Designated as Hedging Instruments.*

The following table presents the effect of energy related derivatives on the PGA mechanism in the balance sheet as of December 31, 2008:

| | Asset Derivatives | | Liability Derivatives | |
|---|---|---|---|---|
| (Dollars in Millions) At December 31, 2008 | Balance Sheet Location [1] | Fair Value | Balance Sheet Location [1] | Fair Value |
| Commodity contracts: | | | | |
| Gas derivatives: | | | | |
| Current | Other regulatory assets | $ 187.2 | Regulatory liabilities | $ -- |
| Total | | $ 187.2 | | $ -- |

1 *Natural gas derivatives are deferred, in accordance with SFAS No. 71 and all increases and decreases in the cost of natural gas supply are passed on to customers with the PGA mechanism. As gains and losses are realized in future periods, they will be recorded as Purchased Gas costs in the Income Statement.*

The following table presents the effect of hedging instruments on OCI and income for the year ended December 31, 2008:

| (Dollars in Millions) | Amount of Gain/(Loss) Recognized in OCI on Derivatives | Location of Gain/(Loss) Reclassified from Accumulated OCI into Income | Amount of Gain/(Loss) Reclassified from Accumulated OCI into Income | Location of Gain/(Loss) Recognized in Income on Derivatives | Amount of Gain/(Loss) Recognized in Income on Derivatives |
|---|---|---|---|---|---|
| Derivatives in SFAS No. 133 Cash Flow Hedging Relationships | Effective Portion [1] | Effective Portion [1] | | Ineffective Portion and Amount Excluded from Effectiveness Testing [2] | |
| Interest rate contracts: | $ -- | Interest Expense | $ 0.3 | | $ -- |
| Commodity contracts: Electric derivatives | (54.4) | Electric generation fuel | (20.0) | Net unrealized gain/(loss) on derivative instruments | -- |
| Electric derivatives | (40.7) | Purchased electricity | -- | Net unrealized gain/(loss) on derivative instruments | (6.1) |
| Gas derivatives | -- | Purchased gas | -- | Net unrealized gain/(loss) on derivative instruments | -- |
| Total | $ (95.1) | | $ (19.7) | | $ (6.1) |

1 *Changes in OCI are reported in after tax dollars.*

2 *Ineffective portion of long-term power supply contracts that are designated as cash flow hedges.*

For derivative instruments that meet cash flow hedge criteria, the effective portion of the gain or loss on the derivative is reported as a component of OCI and reclassified into earnings in the same period or period during which the hedged transaction affects earnings. Gains and losses on the derivatives representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in current earnings.

The following table presents the derivative activity for instruments classified as qualifying cash flow hedges for the year ended December 31, 2008:

| (Dollars in Millions) Year Ended December 31, 2008 | Fair Value Asset/(Liability) | Amount of Gain/(Loss) Recognized In OCI [1] | Amount of Gain/(Loss) Recognized in Income on Derivatives [2] |
|---|---|---|---|
| Electric generation fuel financial Contracts | $ (111.9) | $ (54.4) | $ -- |
| Electric physical contracts | (66.0) | (40.7) | (6.1) |
| Total | $ (177.9) | $ (95.1) | $ (6.1) |

1 *Changes in OCI are reported in after tax dollars.*

2 *Ineffective portion of long-term power supply contracts that are designated as cash flow hedges.*

As of December 31, 2008, the Company reported $0.8 million in net derivative losses related to discontinued cash flow hedges, of which $0.5 million in losses are reported in OCI because the forecasted transaction is considered to be probable. The Company expects that $83.0 million of losses in OCI will be reclassified into earnings within the next 12 months.

The maximum length of time over which the Company is hedging its exposure to the variability in future cash flows extends to February 2015 for the physical electric contracts and to November 2011 for electric generation fuel financial contracts.

The following table presents the effect of derivatives not designated as hedging instruments on income for the year ended December 31, 2008:

| (Dollars in Millions) Year Ended December 31, 2008 | Location of Gain/(Loss) in Income on Derivatives | Amount of Gain/(Loss) Recognized in Income on Derivatives |
|---|---|---|
| Interest rate contracts: | | $ -- |
| Commodity Contracts: | | |
| Electric derivatives | Net unrealized gain/(loss) on derivative instruments | (1.5) |
| Gas derivatives | Net unrealized gain/(loss) on derivative instruments | -- |
| Total | | $ (1.5) |

For the year ended December 31, 2008, the Company reported $1.9 million in losses that were reclassified into earnings as a result of the discontinuance of cash flow hedges because the original forecasted transactions have a remote chance of occurring. The Company also reported year-to-date gains of $0.4 million related to transactions that did not meet NPNS or cash flow hedge criteria.

As of December 31, 2008, the Company had 543 contracts which were considered to be derivatives under SFAS No. 133. The following table presents the number of contracts by commodity type and final settlement year:

| At December 31, 2008 | | | | | | |
|---|---|---|---|---|---|---|
| | Electric Derivatives | | | | Gas Derivatives | |
| | Electric Contracts | | Electric Generation Fuel Contracts | | Gas Contracts | |
| Year | Physical | Financial | Physical | Financial | Physical | Financial |
| 2009 | 3 | -- | 5 | 177 | -- | 71 |
| 2010 | 1 | -- | -- | 148 | -- | 51 |
| 2011 | -- | -- | -- | 65 | -- | 19 |
| 2013 | 2 | -- | -- | -- | -- | -- |
| 2015 | 1 | -- | -- | -- | -- | -- |
| Total | 7 | -- | 5 | 390 | -- | 141 |

The following table presents the Company's derivative volumes by commodity type that are expected to settle each year at December 31, 2008:

AT DECEMBER 31, 2008

| | Electric Derivatives | | | | Gas Derivatives | |
|---|---|---|---|---|---|---|
| | Electric Contracts | | Electric Generation Fuel Contracts | | Gas Contracts | |
| Year | Physical MWhs | Financial MWhs | Physical MMBtu | Financial MMBtu | Physical MMBtu | Financial MMBtu |
| 2009 | 2,623,400 | -- | 1,277,570 | 26,245,000 | -- | 44,154,297 |
| 2010 | 2,519,400 | -- | -- | 21,895,000 | -- | 32,793,905 |
| 2011 | 1,095,675 | -- | -- | 9,830,000 | -- | 8,420,450 |
| 2012 | 1,206,675 | -- | -- | -- | -- | -- |
| 2013 | 485,950 | -- | -- | -- | -- | -- |
| 2014 | 216,075 | -- | -- | -- | -- | -- |
| 2015 | 106,200 | -- | -- | -- | -- | -- |
| Total | 8,253,375 | -- | 1,277,570 | 57,970,000 | -- | 85,368,652 |

The Company is exposed to credit risk primarily through buying and selling electricity and natural 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, and exposure monitoring and exposure mitigation.

Where deemed appropriate, the Company may request collateral or other security from its counterparties to mitigate the potential credit default losses. Criteria employed in this decision include, among other things, the perceived creditworthiness of the counterparty and the expected credit exposure. As of December 31, 2008, the Company held approximately $2.3 million worth of standby letters of credit in support of various electricity and renewable energy credit transactions.

The Company monitors counterparties' credit standing, including those that are experiencing financial problems, have significant swings in credit default swap rates, have credit rating changes by external rating agencies, or have changes in ownership.

It is possible that volatility in energy commodity prices could cause the Company to have material 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, 2008, approximately 99.9% of the counterparties with transaction amounts outstanding in the Company's energy portfolio are rated at least investment grade by the major rating agencies and 0.1% 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.

The Company has entered into commodity master arrangements with its counterparties to mitigate credit exposure to those counterparties. The Company generally enters into the following master arrangements: (1) Western Systems Power Pool agreements (WSPP) - standardized power sales contract in the electric industry; (2) International Swaps and Derivatives Association agreements (ISDA) - standardized financial gas and electric contracts; and (3) North American Energy Standards Board agreements (NAESB) - standardized physical gas contracts. The Company believes that entering into such agreements reduces the risk of default by allowing a counterparty the ability to make only one net payment.

The Company computes credit reserves at a master agreement level (i.e. WSPP, ISDA or NAESB) by counterparty. The Company considers external credit ratings and market factors, such as credit default swaps and bond spreads, in determination of reserves. The Company recognizes that external ratings may not always reflect how a market participant perceives counterparty's risk of default. The company uses both default factors published by Standard & Poor's (S&P) and factors derived through analysis of market risk, which reflect the application of an industry standard recovery rate. The Company selects a default factor by counterparty at an aggregate master agreement level based on a weighted average default tenor for that counterparty's deals. The default tenor is used by weighting fair values and contract tenors for all deals for each counterparty and coming up with an average value. The default factor used is dependent upon whether the counterparty is in a net asset or a net liability position after applying the master agreement levels.

The Company applies the counterparty's default factor to compute credit reserves for counterparties that are in a net asset position. Moreover, the Company applies its own default factor based on the S&P credit rating to compute credit reserves for counterparties in a net liability position. The Company's S&P rating at December 31, 2008 was BBB-. Credit reserves are booked as contra accounts to unrealized gain/(loss) positions. As of December 31, 2008, the Company was in a net liability position with the majority of counterparties, so the default factors of counterparties did not have a significant impact on reserves for the year.

The majority of the Company's derivative contracts are with financial institutions and other utilities operating within the Western Electric Coordinating Council (WECC). The following table presents the number of counterparties and associated S&P credit ratings for the Company's derivative contracts at December 31, 2008:

COUNTERPARTY S&P RATINGS
AT DECEMBER 31, 2008

| RATING | ELECTRIC PHYSICAL | GAS FINANCIAL | GAS PHYSICAL | COMBINED |
|---|---|---|---|---|
| AA+ | -- | 1 | -- | 1 |
| AA | -- | -- | 1 | 1 |
| AA- | 1 | 8 | 1 | 10 |
| A+ | 2 | 6 | -- | 8 |
| A[1] | 1 | 3 | -- | 4 |
| A- | -- | 1 | -- | 1 |
| BBB+ | 1 | -- | -- | 1 |
| BBB | 1 | -- | -- | 1 |
| BB[2] | -- | -- | 1 | 1 |
| Total count | 6 | 19 | 3 | 28 |

1 *One gas financial counterparty received an "A" rating by S&P. The Company assigned a lower internal rating of "BBB."*
2 *Gas physical counterparty not rated by S&P. An internal rating of "BB" was assigned by the Company.*

The Company enters into energy contracts with various credit-risk-related contingent features, which could result in a counterparty requesting immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in a net liability position.

The table below presents the fair value of the overall contractual contingent liability positions for the Company's derivative activity at December 31, 2008:

(DOLLARS IN MILLIONS)
AT DECEMBER 31, 2008

| CONTINGENT FEATURE | FAIR VALUE ASSET /(LIABILITY) | DERIVATIVE EXPOSURE [4] ASSET /(LIABILITY) | POSTED COLLATERAL |
|---|---|---|---|
| Credit Rating [1] | $ (5.4) | $ (13.7) | $ -- |
| Reasonable Grounds for Adequate Assurance [2] | (90.0) | (162.9) | -- |
| Forward Value of Contract [3] | (44.6) | (44.6) | 20.0 |
| Total | $ (140.0) | $ (221.2) | $ 20.0 |

1 *The Company is required to maintain an investment grade credit rating from each of the major credit rating agencies.*
2 *A counterparty with reasonable grounds for insecurity regarding performance of an obligation may request adequate assurance of performance.*
3 *Collateral requirements may vary, based on changes in forward value of underlying transactions.*
4 *Represents derivative and NPNS contract exposures associated with counterparties in net derivative liability positions at December 31, 2008.*

NOTE 18. *Fair Value Measurements*

SFAS No. 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy defined by SFAS No. 157 are as follows:

> Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives and listed equities. Equity securities that are also classified as cash equivalents are considered Level 1 if there are unadjusted quoted prices in active markets for identical assets or liabilities.
>
> Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reported date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange-traded derivatives such as over the counter forwards and options.
>
> Level 3 – Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management’s best estimate of fair value. Level 3 instruments include those that may be more structured or otherwise tailored to customers’ needs. At each balance sheet date, the Company performs an analysis of all instruments subject to SFAS No. 157 and includes in Level 3 all of those whose fair value is based on significant unobservable inputs.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. If a fair value measurement relies on inputs from different levels of the hierarchy, the entire measurement must be placed into the same level based on the lowest level input that is significant to the fair value measurement. The Company’s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The determination of the fair values incorporates various factors that not only include the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests), but also the impact of the Company’s nonperformance risk on its liabilities. The Company uses U.S. Treasury risk free rates in fair value calculations.

As of December 31, 2008, the Company considers the markets for its electric and natural gas Level 2 derivative instruments to be actively traded. Management’s assessment is based on the trading activity volume in real-time and forward electric and natural gas markets. The Company regularly confirms the validity of pricing service quoted prices (e.g. Level 2 in the fair value hierarchy) used to value commodity contracts to the actual prices of commodity contracts entered into during the most recent quarter.

The following table sets forth by level within the fair value hierarchy the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2008.

| RECURRING FAIR VALUE MEASURES (DOLLARS IN MILLIONS) | AT FAIR VALUE AS OF DECEMBER 31, 2008 LEVEL 1 | LEVEL 2 | LEVEL 3 | TOTAL |
|---|---|---|---|---|
| **Assets:** | | | | |
| Energy derivative instruments | $ -- | $ 21.8 | $ 0.5 | $ 22.3 |
| Money market accounts | 24.7 | -- | 1.4 | 26.1 |
| Total assets | $ 24.7 | $ 21.8 | $ 1.9 | $ 48.4 |
| **Liabilities:** | | | | |
| Energy derivative instruments | $ -- | $ 261.2 | $ 134.1 | $ 395.3 |
| Total liabilities | $ -- | $ 261.2 | $ 134.1 | $ 395.3 |

The following table sets forth a reconciliation of changes in the fair value of derivatives classified as Level 3 in the fair value hierarchy:

| (DOLLARS IN MILLIONS) | 2008 |
|---|---|
| Balance at beginning of period (net credit reserve on energy derivatives) | $ (6.1) |
| **Changes during period (reported gross credit reserve):** | |
| Realized and unrealized energy derivatives | |
| - included in earnings | (3.0) |
| - included in other comprehensive income | (110.4) |
| - included in regulatory assets/liabilities | (17.3) |
| Energy derivatives transferred in/out of Level 3 | (2.1) |
| Terminations | (1.5) |
| Other financial items settled | 7.2 |
| Money market accounts | 0.2 |
| Credit reserve | 0.8 |
| Balance as of December 31, 2008 (net credit reserve on energy derivatives) | $ (132.2) |

Realized gains and losses on energy derivatives for Level 3 recurring items are included in energy costs in the Company's income statement under purchased electricity, electric generation fuel or purchased gas when settled.

Unrealized gains and losses for Level 3 inputs on energy derivatives recurring items are included in the net unrealized (gain) loss on derivative instruments section in the Company's income statement and as net unrealized (gain) loss on derivative instruments in other comprehensive income. The Company does not believe that the fair values diverge materially from the amounts the Company currently anticipates realizing on settlement or maturity.

Energy derivative instruments are classified as Level 3 in the fair value hierarchy because Level 3 inputs are significant to their fair value measurement. Energy derivatives transferred out of Level 3 represent existing assets or liabilities that were classified as Level 3 at end of the prior reporting period for which the lowest significant input became observable during the current reporting period. The net unrealized loss recognized during the reporting period is primarily due to a significant decrease in market prices.

## NOTE 19. *Colstrip Matters*

In May 2003, approximately 50 plaintiffs initiated an action against the owners of Colstrip alleging that (1) seepage from two different wastewater pond areas caused groundwater contamination and threatened to contaminate domestic water wells and the Colstrip water supply pond, and (2) seepage from the Colstrip water supply pond caused structural damage to buildings and toxic mold. The defendants reached agreement on a global settlement with all plaintiffs on April 29, 2008 and PSE paid its share of the settlement in the amount of $10.7 million in July 2008. PSE had previously expensed the settlement in the first quarter 2008. PSE has also filed an accounting petition with the Washington Commission to recover such costs in the future.

On March 29, 2007, a second complaint related to pond seepage was filed on behalf of two ranch owners alleging damage due to the Colstrip Units 3 & 4 effluent holding pond. Discovery is on-going and no trial date has been set.

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. Treatment technology studies undertaken by the Colstrip owners estimate that PSE's portion of the costs to comply with the Montana rule could be as much as $11.0 million in construction expenditures and as much as $9.0 million per year in operation and maintenance expenditures but this number could change as new information becomes available. On February 8, 2008, the District of Columbia Federal Court of Appeals vacated the EPA CAMR rule. This action does not invalidate the rule adopted by Montana.

On June 15, 2005, 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 (BART) requirements for electric generating units, including presumptive limits for sulfur dioxide, particulate matter and nitrogen oxide controls for large units. In February 2007, Colstrip was notified by EPA that Colstrip Units 1 & 2 were determined to be subject to BART requirements. PSE submitted a BART engineering analysis for Colstrip Units 1 & 2 in August 2007. PSE cannot yet determine the need for or costs of additional controls to comply with this rule.

The Minerals Management Service of the United States Department of Interior (MMS) issued a series of orders to Western Energy Company (WECO) to pay additional taxes and royalties concerning coal WECO sold to the owners of Colstrip 3 & 4 and similar orders have been issued in the administrative appellate process. The orders asserted that additional royalties are owed in connection with payments received by WECO from Colstrip 3 & 4 owners (including PSE) for the construction and operation of a conveyor system that runs several miles from the mine to Colstrip 3 & 4. The state of Montana also issued a demand to WECO consistent with the MMS position. In November and December 2008, WECO and the Colstrip 3 & 4 owners reached settlements of these issues with the state of Montana and with MMS. The settlements will result in payments of agreed amounts with respect to the allegedly past due payments, and establish an ongoing payment process for keeping all future obligations current. PSE's outstanding payment for the past due amounts in total is $2.8 million which has been fully reserved.

The MMS also issued an order to WECO concerning allegedly unpaid past due royalties for a "gross inequity" settlement that WECO, Montana Power Company and PSE entered into in 1997. In December 2008, WECO and MMS reached a settlement in principle of this MMS claim. Under the 1997 settlement, PSE will reimburse WECO for such payments. The payment will likely be made in the first quarter 2009, after documentation is complete, in the approximate amount of $1.9 million. This amount has been fully reserved.

A lawsuit was filed in February 2009 against the Colstrip operator related to a fatality that occurred at the plant in June 2008. PSE's level of exposure in this matter is currently unknown.

NOTE 20. *Taxes Other Than Income Taxes*

| (DOLLARS IN THOUSANDS) | 2008 | 2007 | 2006 |
|---|---|---|---|
| Taxes other than income taxes: | | | |
| Real estate and personal property | $ 45,841 | $ 49,873 | $ 39,832 |
| State business | 123,137 | 118,954 | 107,140 |
| Municipal and occupational | 117,567 | 111,241 | 97,671 |
| Other | 31,935 | 35,836 | 33,144 |
| Total taxes other than income taxes | $ 318,480 | $ 315,904 | $ 277,787 |
| Charged to: | | | |
| Operating expense | $ 297,128 | $ 288,417 | $ 255,712 |
| Other accounts, including construction work in progress | 21,352 | 27,487 | 22,075 |
| Total taxes other than income taxes | $ 318,480 | $ 315,904 | $ 277,787 |

NOTE 21. *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 Institute of Electrical and Electronics Engineers (IEEE) outage criteria for system average interruption duration index. PSE's storm accounting, which allows deferral of certain storm damage costs, was subject to review by the Washington Commission at the end of the current three-year period, which was December 31, 2007. In PSE's electric general rate case, the annual threshold at which qualifying storm costs may be deferred has been increased to $8.0 million beginning with calendar year 2009. In 2008, PSE incurred $11.4 million in storm-related electric transmission and distribution system restoration costs, of which $1.4 million was deferred. In 2007, PSE incurred $38.3 million in storm-related electric transmission and distribution system restoration costs, of which $29.3 million was deferred.

ELECTRIC GENERAL RATE CASE

On October 8, 2008, the Washington Commission issued its order in PSE's electric general rate case filed in December 2007, approving a general rate increase for electric customers of $130.2 million or 7.1% annually. The rate increase for electric gas customers was effective November 1, 2008. In its order, the Washington Commission approved a weighted cost of capital of 8.25%, or 7.00% after-tax, and a capital structure that included 46.0% common equity with a return on equity of 10.15%.

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 became 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

PCORC, a limited-scope proceeding, was approved in 2002 by the Washington Commission to periodically reset power cost rates. In addition to providing the opportunity to reset all power costs, the PCORC proceeding also provides for timely review of new resource acquisition costs and inclusion of such costs in rates at the time the new resource goes into service. To achieve this objective, the Washington Commission approved an expedited five-month PCORC decision timeline rather than the statutory 11-month timeline for a general rate case.

On March 20, 2007, PSE submitted a PCORC filing to request approval of an updated power cost baseline rate beginning September 2007. The PCORC filing also requested recovery of ownership and operating costs of the Goldendale generating facility (Goldendale) through retail electric rates. On May 23, 2007, PSE filed updated power costs due to changes in market conditions of natural gas and other costs which resulted in a revised proposed increase of $77.8 million or 4.4% annually. On July 5, 2007, a settlement agreement in this PCORC signed by PSE and certain other parties to the proceeding was filed with the Washington Commission, the terms of which included an electric rate increase of $64.7 million. On August 2, 2007, the Washington Commission approved the settlement agreement and authorized an increase in PSE's electric rates of $64.7 million or an average increase of 3.7% annually effective September 1, 2007. The investment in Goldendale was found prudent, thus allowing for recovery of certain ownership and operating costs through electric retail rates effective September 1, 2007 along with updating other power costs.

In accordance with the August 2, 2007 Washington Commission order approving the PCORC settlement, PSE and other parties agreed to conduct a collaborative stakeholder review of the PCORC process to consider the scope and timing of the PCORC mechanism. The collaborative review included but was not limited to: (1) the number of PCORCs that a company will be allowed to file in any given year; (2) the number and timing of updates that a company may submit in the PCORC process; (3) the items directly associated with power costs that may be included and considered in a PCORC filing; and (4) whether the number and timing of updates may vary depending on if other parties can easily verify. On December 12, 2007 the collaboration filed a final report with the Washington Commission reporting that the parties were not able to reach agreement on revisions to the PCORC mechanism and that the parties would address such issues in the Company's pending general rate case filing. On January 15, 2009, the Washington Commission issued an order that authorized the continuation of the PCORC with certain modifications to which the Washington Commission staff and the Company agree. The five procedural modifications to the PCORC include extending the expected procedural schedule from five to six months, limiting the power cost updates to one per PCORC unless an additional update is allowed by the Washington Commission as part of the compliance filing, prohibiting the overlap of PCORC and general rate cases (except for requests for interim rate relief), shortening data request time from ten to five business days, and requiring the Company to provide its AURORA data files to Public Counsel and intervenors at the outset of a case.

ACCOUNTING ORDERS AND PETITIONS

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 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 April 11, 2007, the Washington Commission approved PSE's petition for issuance of an accounting order that authorizes PSE to defer certain ownership and operating costs (and associated carrying costs) PSE incurred related to its purchase of Goldendale during the period prior to inclusion in PSE's retail electric rates in the PCORC. The deferral is for the time period from March 15, 2007 through September 1, 2007. As of December 31, 2008, PSE had established a regulatory asset of $11.8 million. Recovery of these costs over a period of three years began November 2008 as allowed in the October 2008 general rate case order.

On April 13, 2007, PSE filed an accounting petition for a Washington Commission order authorizing the deferral and use of net revenues from the sale of Renewable Energy Credits (RECs) and Emission Reduction Allowances (ERA) to further the development of renewable generation resources in Washington State or to be credited to customers. The accounting petition also requests approval of amortization of the deferred REC and ERA proceeds to expense.

On May 30, 2007, PSE agreed to extend the terms of the existing leases of its Bellevue corporate office complex from ten years to 15 years. PSE's lease agreement included a one-time right to purchase the office complex. PSE elected to monetize the value of this purchase option and negotiated for a cash payment of $18.9 million, net of transaction fees, in exchange for the termination of the purchase option. PSE received authorization for deferred accounting treatment of the net proceeds in the 2007 General Rate Case. Amortization began effective November 1, 2008 for a period of 12 years.

On May 21, 2008, PSE filed an accounting petition for a Washington Commission order authorizing the deferral of a settlement payment of $10.7 million incurred as a result of the recent settlement of a lawsuit in the state of Montana over alleged damages caused by the operation of Colstrip.

On May 28, 2008, the Washington Commission authorized PSE to defer to a maximum of $2.3 million of costs associated with the FERC required studies of Baker River Dam. The accounting petition allows PSE to defer costs incurred from January 8, 2007 through December 31, 2010.

On November 5, 2008, PSE filed an accounting petition for a Washington Commission order authorizing the deferral and recovery of interest due the IRS for tax years 2001 to 2006 along with carrying costs incurred in connection with the interest due. In October 2005, the Washington Commission issued an order authorizing the deferral and recovery of costs associated with increased borrowings necessary to remit deferred taxes to the IRS.

On November 6, 2008, PSE filed an accounting petition for a Washington Commission order authorizing accounting treatment and amortization related to payments received for taking assignment of Westcoast Pipeline Capacity. The accounting petition seeks deferred accounting treatment and amortization of the regulatory liability to power costs beginning in November 2009 and extending over the remaining primary term of the pipeline capacity contract through October 31, 2018.

On November 15, 2008, PSE filed an accounting petition for a Washington Commission order determining that its newly acquired Mint Farm complies with the Washington State greenhouse gases (GHG) emissions performance standard. Under this standard PSE can defer the costs associated with Mint Farm until the cost of the plant is included in rates. The Company is currently deferring both variable and fixed costs as allowed. The Mint Farm purchase was completed on December 5,

2008. On December 23, 2008 the Washington Commission set this matter for hearing. PSE expects to receive an order by the third quarter 2009.

On December 30, 2008, the Washington Commission approved an order authorizing the sale of Puget Energy and PSE to Puget Holdings subject to a Settlement Stipulation which included 78 conditions. Items included in the conditions that may affect the financial statements are dividend restrictions for Puget Energy and PSE. These items are discussed in Note 6. In addition, the conditions provided for rate credits of $10.0 million per year due to merger savings and a lower return by the investor consortium over a ten-year period beginning at the closing of the transaction.

### Residential Exchange Deferred Asset

On May 21, 2007, the BPA notified PSE and other investor-owned utilities that BPA was suspending payments related to its residential exchange program (REP) due to adverse Ninth Circuit Court of Appeals (Ninth Circuit) decisions of May 3, 2007. The Ninth Circuit concluded in its decisions that certain BPA actions in entering into residential exchange settlements in 2000 were not in accordance with the law. BPA suspended payments under the REP as a result of the Ninth Circuit decisions. As a result of the BPA suspension of payment, PSE filed revisions to the tariffs which pass through the benefits of the REP to all residential and small farm customers. The Washington Commission approved the termination of the Residential Exchange Credit effective June 7, 2007. Under Federal law investor-owned utilities receiving REP benefits must pass-through the benefits to their residential and small farm electric customers.

On August 29, 2007, the Washington Commission approved PSE's accounting petition to defer as a regulatory asset the excess REP benefit provided to customers and accrue monthly carrying charges on the deferred balance from June 7, 2007 until the deferral is recovered from customers or BPA. The accounting petition sought approval to record carrying costs on the deferred balance until the deferred balance is recovered from customers. In March 2008, BPA and PSE signed an agreement pursuant to which BPA (on April 2, 2008) paid PSE $53.7 million in REP benefits for fiscal year ending September 30, 2008, which payment is subject to true-up depending upon the amount of any REP benefits ultimately determined to be payable to PSE. In April 2008, the Washington Commission approved PSE's tariff filing seeking to pass-through the net amount of the benefits under the interim agreements to residential and small farm customers. The Washington Commission also approved PSE's request to credit the regulatory asset amount of $33.7 million against the $53.7 million payment and pass-through to customers the remaining amount of approximately $20.0 million, which occurred during the second quarter 2008. These amounts did not affect PSE's net income. PSE began amortization of the accrued carrying charges on the regulatory asset totaling $3.1 million at September 30, 2008 on November 1, 2008 over a two year period as determined in PSE's electric general rate case. On October 30, 2008, the Washington Commission approved PSE's tariff request to resume the REP pass-through credits to residential electric customers. The result is a 9.9% reduction to residential electric customers bill without an impact on earnings.

### Production Tax Credit

PSE has a tariff schedule which passes the benefits of the Production Tax Credit (PTCs) to customers based on estimated generation of the PTC credits. PSE may adjust the PTC tariff annually based on differences between the PTC credits provided to the customers and the PTC credits actually earned, plus estimated PTC credits for the following year, less interest associated with the deferred tax balance for the PTC credits. The tariff is not subject to the sharing bands in the PCA. Since customers receive 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 for its carrying costs for funds through this calculation.

On October 30, 2006, PSE revised its PTC electric tariff to increase the revenue credit to customers from $13.1 million to $28.8 million, effective January 1, 2007. On December 12, 2007, PSE revised its PTC electric tariff to decrease the revenue credit to customers from $28.8 million to $28.6 million, effective January 12, 2008. PSE will be revising the tariff effective January 1, 2009 based on a filing made in the fourth quarter 2008.

### PCA Mechanism

In 2002, the Washington Commission approved a PCA mechanism that triggers if PSE's costs to provide customers' electricity varies from a power cost baseline rate established in a rate proceeding. 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 continuation of the PCA mechanism 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 |
|---|---|---|---|
| +/- $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 PCORC 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.*

### Gas Regulation and Rates

#### Gas General Rate Case

On October 8, 2008, the Washington Commission issued its order in PSE's natural gas general rate case filed in December 2007, approving a general rate increase for natural gas rates of $49.2 million or 4.6% annually. The rate increases for natural gas customers were effective November 1, 2008. In its order, the Washington Commission approved a weighted cost of capital of 8.25%, or 7.00% after tax and a capital structure that included 46.0% common equity with a return on equity of 10.15%.

On January 5, 2007, the Washington Commission issued its order in PSE's natural gas general rate case, granting an increase for natural gas customers of $29.5 million or 2.8% annually, effective beginning January 13, 2007 which resulted in an increase in gas margin of approximately 9.8% annually. 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 natural 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 25, 2008, the Washington Commission approved PSE's requested revisions to its PGA tariff schedules resulting in an increase of $108.8 million or 11.1% on an annual basis in gas sales revenues effective October 1, 2008. The rate increase was the result of higher costs of natural gas in the forward market and a reduction of the credit for the accumulated PGA payable balance. The PGA rate change will increase PSE's 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 2008, 2007 and 2006:

| Effective Date | Percentage Increase (Decrease) in Rates | Annual Increase (Decrease) in Revenues (Dollars In Millions) |
|---|---|---|
| October 1, 2008 | 11.1 % | $ 108.8 |
| October 1, 2007 | (13.0) % | (148.1) |
| October 1, 2006 | 10.2 % | 95.1 |

NOTE 22. *Other*

The Washington Commission issued an order on May 13, 2004 determining that PSE did not prudently manage natural gas costs for the Tenaska Power Fund, L.P. (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 $6.4 million, $7.8 million and $9.0 million in 2008, 2007 and 2006, 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, 2008, the White River project net book value totaled $71.0 million, which included $40.3 million of net utility plant, $15.3 million of capitalized FERC licensing costs, $5.9 million of costs related to construction work in progress and $9.5 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 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.

A variable interest entity (VIE) is an entity in which the equity of the investors as a group do not have: (1) the characteristics of a controlling financial interest; (2) sufficient equity at risk for the entity to finance its activities without additional subordinated financial support; or (3) symmetry between voting rights and economic interests and where substantially all of the entity's activities either involve or are conducted on behalf of an investor with disproportionally few voting rights. Variable interests in a VIE are contractual, ownership or other pecuniary interests in an entity that change with changes in the fair value of the entity's net assets exclusive of variable interest.

FIN 46R requires that if a business entity has a controlling financial interest in a VIE, 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.

In December 2008, FASB issued FIN 46R-8, "Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interests in Variable Interest Entities" (FIN 46R-8), which requires new expanded disclosures in the financial statements for year ended December 31, 2008 for VIEs. FIN 46R-8 amends Interpretation 46R to require certain disclosures by a public enterprise that is (a) a sponsor that has a variable interest in a variable interest entity (irrespective of the significance of the variable interest) and (b) an enterprise that holds a significant variable interest in a qualifying special purpose entity (SPE) but was not the transferor (nontransferor enterprise) of financial assets to the qualifying SPE. The disclosures required by FIN 46R-8 are intended to provide users of the financial statements with greater transparency about a transferor's continuing involvement with transferred financial assets and an enterprise's involvement with VIEs.

A primary beneficiary of a VIE is the variable interest holder (e.g. a contractual counterparty or capital provider) deemed to have the controlling financial interest(s) and is considered to be exposed to the majority of the risks and rewards associated with the VIE and therefore must consolidate it. The Company enters into a variety of contracts for energy with other counterparties and evaluates all contracts for variable interests. The Company's variable interests primarily arise through power purchase agreements where the Company obtains control other than through voting rights and is required to buy all or a majority of generation from a plant at rates set forth in a power purchase agreement, subject to displacement. If a counterparty does not deliver energy to the Company, the Company may have to replace the energy at prices which could be higher or lower than agreed to prices. Therefore, the Company may be exposed to risk associated with replacement costs of a contract.

The Company evaluates variable interest relationships based on significance. If the Company did not participate significantly in the design or redesign of an entity, and the variable interest is not considered significant to the Company's financial statements, the variable interest is not considered significant. Purchase power contracts with governmental organizations do not require disclosure. When the Company determines a significant variable interest may exist with another party, the Company requests for information to determine if it is required to be consolidated.

The following table presents the Company's VIE relationships, irrespective of significance, related to power purchase agreements as of December 31, 2008:

| (Dollars in Millions) | Variable Interests in Power Purchase Agreements for the Year Ended December 31, 2008 | | | |
|---|---|---|---|---|
| Nature of Variable Interest | Longest Contract Tenor | Number of Counterparties | Aggregate Carrying Value Asset/(Liability) [2] | Level of Activity - 2008 Expenses [2] |
| Electric- Combustion Turbine Co-generation plant [1] | 2011 | 2 | $ (17.1) | $ 196.8 |
| Electric- Hydro | 2037 | 8 | (0.9) | 12.4 |
| Other | 2011 | 2 | -- | 0.4 |
| Total | | 12 | $ (18.0) | $ 209.6 |

[1] *Variable interests may be significant.*

[2] *Carrying values are classified in the balance sheet in accounts payable and expenses are classified on the income statement in purchased electricity.*

The Company evaluated its power purchase agreements and determined that three power purchase agreements may be considered significant VIEs under FIN 46R. One of these counterparties, Sumas Cogeneration Company, L.P. (Sumas), notified PSE that it no longer intended to deliver energy to PSE through the remaining term of its contract. After negotiations, PSE completed the purchase of the 125 MW Sumas cogeneration power plant in July 2008.The Company is required to buy all the generation from the remaining two plants, subject to displacement by the Company, at rates set forth in the relevant power purchase agreements. As a result, the Company submitted requests for information to those parties; however, the parties have refused to submit to the Company the necessary information for the Company to determine whether they meet the requirements of a VIE that requires consolidation. The Company will continue to submit requests for information to the counterparties annually to determine if FIN 46R is applicable.

PSE's purchased electricity expense for 2008, 2007 and 2006 for these entities was $196.3 million, $216.5 million and $259.8 million, respectively.

As of December 31, 2008, PSE had $7.2 million in insurance receivables recorded related to a property damage claim and a general liability claim. PSE is engaged in settlement discussions with the insurer of the general liability claim and has stated the carrying value of its receivable for this claim at management's estimate of the net realizable value as of December 31, 2008. PSE believes the property damage claim represents an insurable loss and has filed a notice of loss with its property insurers.

In November 2007, WECC audited PSE's compliance with electric reliability standards adopted by FERC, the North American Electric Reliability Corporation (NERC) and/or WECC. Compliance with these standards includes periodic self-certifications of compliance, self-reports of violations after discovery of the violation, spot checks to review self-certifications and external audits that review compliance with designated standards. During the November 2007 audit the WECC audit team identified four potential violations of the 44 standards audited that PSE had not previously self-reported. Several months after the audit, WECC issued a "Notice of Alleged Violation and Proposed Penalty Sanctions" to PSE, adding details of the violations and proposed penalties to the alleged violations. In accordance with the Compliance Monitoring Enforcement Program process, PSE met with WECC representatives in July 2008 to discuss settlement. PSE believes that all issues concerning the four alleged violations will be resolved. Resolution of reliability standards violations will be an ongoing concern; however, PSE self-reports violations when they are discovered. Such self-reports could result in settlement of issues without a penalty or issuances of penalties in the future. PSE has established a loss reserve of $0.8 million related to these alleged violations.

NOTE 23. *Commitments and Contingencies*

For the year ended December 31, 2008, approximately 21.5% of the Company's energy output was obtained at an average cost of approximately $0.017 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, 2008, the Company was entitled to purchase portions of the power output of the PUDs' projects as set forth in the following tabulation:

| Project | Contract Exp. Date | License[1] Exp. Date | Total Bonds Outstanding 12/31/08[2] (Millions) | Company's Annual Amount Purchasable (Approximate): % of Output | Megawatt Capacity | Cost[3] (Millions) |
|---|---|---|---|---|---|---|
| Rock Island | | | | | | |
| Original units | 2012 | 2029 | $ 154.6 | 50.0 | 312 | $ 35.5 |
| Additional units | 2012 | 2029 | 321.2 | 50.0 | | |
| Rocky Reach [4] | 2011 | 2006 | 320.7 | 38.9 | 498 | 28.9 |
| Wells | 2018 | 2012 | 186.7 | 29.9 | 231 | 11.8 |
| Priest Rapids [5,6,7] | 2052 | 2052 | 247.8 | 4.3 | 41 | 13.0 |
| Wanapum [5,6,7] | 2052 | 2052 | 422.0 | 10.8 | 112 | 7.5 |
| Total | | | $ 1,653.0 | | 1,194 | $ 96.7 |

1 *The Company is unable to predict whether the licenses under the Federal Power Act (FPA) 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: 83.6% at Rock Island; 80.6% at Rocky Reach; 32.4% at Wells; 0.0% at Priest Rapids; and 0.0% at Wanapum.*

3 *The components of 2008 costs associated with the interest portion of debt service are: Rock Island, $12.8 million for all units; Rocky Reach, $8.0 million; Wells, $3.0 million; Priest Rapids, $0.5 million; and Wanapum, $2.3 million.*

4 *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. 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 Washington Commission.*

5 *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.*

6 *In 2008, Grant PUD received a new, 44-year license from the Federal Energy Regulatory Commission to operate both the Priest Rapids and the Wanapum projects. The new contracts are concurrent with the new license.*

7 *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 will also be adjusted annually for the remaining term of the new contract.*

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) | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 & THERE-AFTER | TOTAL |
|---|---|---|---|---|---|---|---|
| Columbia River projects | $ 92.8 | $ 111.6 | $ 130.1 | $ 82.0 | $ 86.9 | $ 1,486.4 | $ 1,989.8 |
| Other utilities | 179.4 | 178.3 | 128.2 | 111.3 | 51.5 | 351.5 | 1,000.2 |
| Non-utility generators | 200.0 | 207.4 | 197.4 | -- | -- | -- | 604.8 |
| Total | $ 472.2 | $ 497.3 | $ 455.7 | $ 193.3 | $ 138.4 | $ 1,837.9 | $ 3,594.8 |

Total purchased power contracts provided the Company with approximately 8.7 million, 9.4 million and 9.6 million megawatt hours (MWh) of firm energy at a cost of approximately $384.0 million, $390.6 million and $421.7 million for the years 2008, 2007 and 2006, 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 natural gas is reflective of the daily price of natural gas at the United States/Canada border near Sumas, Washington. PSE has entered into financial arrangements to hedge future natural gas supply costs associated with this obligation. The Company has a maximum financial obligation under hedge agreements of $23.6 million in 2009. The Company has obligations for natural gas supply amounting to $12.5 million in 2009 for the Tenaska plant.

As part of its electric operations and in connection with the 1999 buyout of the Cabot natural 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 has natural gas-fired generation facility obligations for natural gas supply amounting to an estimated $37.7 million in 2009. Two longer term agreements for natural gas supply amount to an estimated $221.0 million for 2010 through 2028.

PSE enters into short-term energy supply contracts to meet its core customer needs. These contracts are generally classified as NPNS or in some cases recorded at fair value in accordance with SFAS No. 133 and SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS No. 149). Commitments under these contracts are $372.9 million, $250.6 million and $84.9 million in 2009, 2010 and 2011 respectively.

### NATURAL GAS SUPPLY

The Company has also entered into various firm supply, transportation and storage service contracts in order to ensure adequate availability of natural gas supply for its firm customers. Many of these contracts, which have remaining terms from less than one year to 36 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 natural 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 2008 for firm natural gas supply, firm transportation service and firm storage and peaking service of $1.1 million, $100.3 million and $7.8 million, respectively. The Company incurred demand charges in 2008 for firm transportation service for the natural gas supply for its combustion turbines in the amount of $13.8 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) | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 & THERE-AFTER | TOTAL |
|---|---|---|---|---|---|---|---|
| Firm natural gas supply | $ 0.8 | $ 0.5 | $ 0.5 | $ -- | $ -- | $ -- | $ 1.8 |
| Firm transportation service | 116.0 | 114.6 | 106.4 | 104.0 | 99.7 | 268.1 | 808.8 |
| Firm storage service | 8.8 | 8.2 | 7.8 | 7.7 | 3.2 | 10.6 | 46.3 |
| Total | $ 125.6 | $ 123.3 | $ 114.7 | $ 111.7 | $ 102.9 | $ 278.7 | $ 856.9 |

SERVICE CONTRACTS

On August 30, 2001, PSE signed a contract that provides data processing and billing services for PSE. The obligations under the contract are $24.1 million in 2009, $24.7 million in 2010 and $16.8 million in 2011. The contract expires in August 2011.

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 $0.6 million in 2009, $0.5 million in 2010, $0.6 million in 2011, $0.6 million in 2012, $0.6 million in 2013 and $3.3 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) which provides for the operation, maintenance and remedy of any defects or deficiencies in the constructed wind turbine generators (WTGs) at Hopkins Ridge and their associated equipment on PSE's behalf. The OM&W Agreement provides for a five-year term continuing until November 2010. The annual fee was approximately $2.6 million in 2008 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 OM&W agreement which provides for the operation, maintenance and remedy of any defects or deficiencies in the constructed WTGs at Wild Horse and their associated equipment on PSE's behalf. The Agreements provide for a five-year term continuing until November 2011. The annual fee was approximately $5.8 million in 2008 and will escalate each January 1 thereafter during the term by the Gross Domestic Product Implicit Price Deflator.

PSE entered into a Contractual Service Agreement (CSA) in December 2007 for continued operations, maintenance and upgrading of the Goldendale combined cycle generation turbine plant. The contract is scheduled to end in 2017. The obligations under the contract are $0.6 million in 2009, $0.7 million in 2010, $0.7 million in 2011 and $4.4 million thereafter.

In July 2008, in connection with its purchase of the Sumas combined cycle generation station (Sumas), PSE became subject to an existing CSA. The CSA is for planned services on both the gas and steam turbine generating units. The contract was entered into by Sumas effective June 2001 and runs for the earlier of 56,000 factored fired hours or the completion of the second hot gas path inspection, estimated to be in 2012. The obligations under the contract are $10,000 in 2009, $113,000 in 2010, $116,000 in 2011 and $80,000 thereafter.

In December 2008, in connection with its purchase of the Mint Farm natural gas fired electric generating facility, PSE became subject to an existing CSA. The CSA is for planned services and operations. The contract was entered into by Mint Farm effective June 2004 and expires in 2039. The obligations under the contract are $0.4 million in 2009, $0.5 million in 2010, $0.5 million in 2011 and $14.4 million thereafter.

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. On November 14, 2008, GE Capital Commercial Inc. notified PSE of its intention to cancel the lease effective January 14, 2009. Management is currently evaluating whether to sell or purchase the combustion turbines, with a purchase deemed the most likely outcome. Payments under the lease vary with changes in the LIBOR. At December 31, 2008, PSE's outstanding balance under the lease was $45.4 million. The expected residual value under the lease is $42.6 million. 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 $4.1 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 EPA, 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 reviews its estimated future obligations and adjusts loss reserves quarterly as management believes necessary per the guidance of SFAS No. 5 and FIN No. 14, "*Reasonable Estimation of the Amount of a Loss*." Management's estimates include an assessment of the impact of the potential outcomes of disputes with certain property owners and other potentially responsible parties. The Company believes a significant portion of its past and future environmental remediation costs are recoverable from insurance companies, from third parties or from customers under a Washington Commission order. At December 31, 2008, the Company had $4.4 million and $50.2 million in deferred electric and natural gas environmental costs, respectively.

In November 2006, PSE's Crystal Mountain Generation Station had an accidental release of approximately 18,000 gallons of diesel fuel. PSE crews and consultants responded and worked with applicable state and federal agencies to control and remove the spilled diesel. On July 11, 2007, PSE received a Notice of Completion for work performed pursuant to the Administrative Order for Removal from EPA. The Notice stated that PSE had met the requirements of the Order and the accompanying scope of work. Total removal costs as of December 31, 2007 were approximately $14.0 million. PSE estimates the total remediation cost to be approximately $15.0 million, which has been accrued or paid. At December 31, 2008, PSE had an insurance receivable recorded in the amount of $5.7 million associated with this fuel release. PSE received a partial payment on this receivable of $5.0 million in January 2008. In January 2009, PSE received a partial payment of $3.6 million reducing the receivable amount to $2.1 million. PSE has paid a civil penalty of $471,000 related to this matter. PSE has also responded to a request for information under the Clean Water Act from EPA. On February 13, 2008, the Department of Justice issued a letter to PSE seeking civil penalties pursuant to the Clean Water Act on behalf of EPA. A settlement was reached regarding these claims, including natural resource damage claims related to the diesel spill. Thereafter, a consent decree was lodged on November 25, 2008 requiring reimbursement of $49,000 in costs and $513,000 for natural resource damages. Separately, PSE is still in negotiations with the State of Washington regarding its fine of $366,000. The Company believes its loss reserve is sufficient.

## NOTE 24. *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 and development company and a holding company for a small non-utility wholesale generator. Reconciling items between segments are not significant.

| 2008 (Dollars in Thousands) | Regulated Utility | Other | Puget Energy Total |
|---|---|---|---|
| Revenues | $ 3,351,109 | $ 6,665 | $ 3,357,774 |
| Depreciation and amortization | 311,920 | 208 | 312,128 |
| Income tax | 59,071 | 835 | 59,906 |
| Operating income | 386,912 | (4,164) | 382,748 |
| Interest charges, net of AFUDC | 193,978 | (6) | 193,972 |
| Net income from continuing operations | 159,373 | (4,444) | 154,929 |
| Total assets | 8,282,278 | 86,128 | 8,368,406 |
| Construction expenditures - excluding equity AFUDC | 846,001 | -- | 846,001 |

| 2007 (Dollars in Thousands) | Regulated Utility | Other | Puget Energy Total |
|---|---|---|---|
| Revenues | $ 3,207,061 | $ 13,086 | $ 3,220,147 |
| Depreciation and amortization | 279,014 | 208 | 279,222 |
| Income tax | 70,794 | 1,788 | 72,582 |
| Operating income | 439,433 | 1,601 | 441,034 |
| Interest charges, net of AFUDC | 205,209 | | 205,209 |
| Net income from continuing operations | 184,049 | 627 | 184,676 |
| Total assets | 7,513,884 | 84,852 | 7,598,736 |
| Construction expenditures - excluding equity AFUDC | 737,258 | -- | 737,258 |

| 2006 (Dollars in Thousands) | Regulated Utility | Other | Puget Energy Total |
|---|---|---|---|
| Revenues | $ 2,899,234 | $ 7,829 | $ 2,907,063 |
| Depreciation and amortization | 262,129 | 212 | 262,341 |
| Income tax | 96,727 | (4,240) | 92,487 |
| Operating income | 416,734 | 4,117 | 420,851 |
| Interest charges, net of AFUDC | 168,138 | -- | 168,138 |
| Net income (loss) from continuing operations | 172,644 | (5,420) | 167,224 |
| Total assets | 6,993,131 | 72,908 | 7,066,039 |
| Construction expenditures - excluding equity AFUDC | 749,516 | -- | 749,516 |

NOTE 25. *Agreement and Plan of Merger*

On February 6, 2009, Puget Holdings completed its merger with Puget Energy. Puget Holdings is a consortium of long-term infrastructure investors led by Macquarie Infrastructure Partners I, the Canada Pension Plan Investment Board and British Columbia Investment Management Corporation, and also includes Alberta Investment Management Corporation, Macquarie-FSS Infrastructure Trust, Macquarie Infrastructure Partners II and Macquarie Capital Group Limited (collectively, the Consortium). At the effective time of the merger, each issued and outstanding share of common stock of Puget Energy, other than any shares in respect of which dissenter's rights are perfected and other than any shares owned by the Consortium, were cancelled and were converted automatically into the right to receive $30.00 in cash, without interest. As a result of the merger, Puget Energy is the direct wholly owned subsidiary of Puget Equico LLC, which is an indirect wholly owned subsidiary of Puget Holdings.

NOTE 26. *Litigation*

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, 2008, the net receivable for such sales was approximately $21.1 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 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 remanded to FERC the question of whether to allow refunds. In March and April 2008, FERC issued orders establishing procedures for the *Lockyer* remand. The orders commence a seller-by-seller inquiry into the transaction reports filed by entities that sold power in California during 2000. The inquiry is to determine if the transaction reports as filed masked the gathering of more than 20.0% of the market during the period by that seller. The California parties sought rehearing on a variety of these issues. On October 6, 2008, FERC issued a decision on the rehearing request that reaffirmed its intent to impose seller-specific remedies rather than the market-wide remedy sought by the California parties. The rehearing decision also reconfirms FERC's method for determining market share, limits the scope of the proceeding and declines to defer the proceeding pending remand from the Ninth Circuit of the California Refund Proceeding and the Port of Seattle (Pacific Northwest Refund) case. PSE believes that it will not be found to have possessed 20.0% of any relevant market during any relevant time. The proceeding continues, including a settlement process before an ALJ. Settlement talks among various parties continue but PSE cannot predict the ultimate outcome of any negotiations or subsequent process before FERC or the ALJ.

***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. Rehearing by the Ninth Circuit on this matter was sought on November 16, 2007. The rehearing petition has not been acted upon. In addition, parties have been engaged in court-sponsored settlement discussions, and those discussions may result in some settlements. PSE is unable to predict either the outcome of the proceedings or the ultimate financial effect on 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. On August 24, 2007, the Ninth Circuit issued a decision concluding that FERC should have evaluated and considered evidence of market manipulation in California and its potential impact in the Pacific Northwest. It also decided that FERC should have considered purchases made by the California Energy Resources Scheduler and/or the California Department of Water Resources in the Pacific Northwest Proceeding. On December 17, 2007, PSE and Powerex separately filed requests for rehearing with the Ninth Circuit of this decision. Those requests remain pending. PSE intends to vigorously defend its position in this proceeding, but it is unable to predict the outcome of this matter.

PROCEEDING RELATING TO THE MERGER

On October 26, 2007 and November 2, 2007, two separate lawsuits were filed against the Company and all of the members of the Company's Board of Directors in Superior Court in King County, Washington. The lawsuits, respectively, are entitled, *Tansey v. Puget Energy, Inc., et al.*, Case No. 07-2-34315-6 SEA and *Alaska Ironworkers Pension Trust v. Puget Energy, Inc., et al.*, Case No. 07-2-35346-1 SEA. The lawsuits are both denominated as class actions purportedly on behalf of Puget Energy's shareholders and assert substantially similar allegations and causes of action relating to the merger. The complaints allege that the Company's directors breached their fiduciary duties in connection with entering into the merger agreement and seek virtually identical relief, including an order enjoining the consummation of the merger. Pursuant to a court order dated November 26, 2007, the two cases were consolidated for all purposes and entitled *In re Puget Energy, Inc. Shareholder Litigation*, Case No. 07-2-34315-6 SEA.

On February 6, 2008, the Company entered into a memorandum of understanding providing for the settlement of the consolidated shareholder lawsuit, subject to customary conditions including completion of appropriate settlement documentation, confirmatory discovery and court approval. Pursuant to the memorandum of understanding, the Company agreed to include certain additional disclosures in its proxy statement relating to the merger. The Company does not admit, however, that its prior disclosures were in any way materially misleading or inadequate. In addition, the Company and the other defendants in the consolidated lawsuit deny the plaintiffs' allegations of wrongdoing and violation of law in connection with entering into the merger agreement. The settlement, if completed and approved by the court, will result in dismissal with prejudice and release of all claims of the plaintiffs and settlement class of the Company's shareholders that were or could have been brought on behalf of the plaintiffs and the settlement class. In connection with such settlement, the plaintiffs intend to seek a court-approved award of attorneys' fees and expenses in an amount up to $290,000, which the Company has agreed to pay. As of December 31, 2008, the Company has a loss reserve of $290,000. The settlement approval process has begun and will take several months to complete.

PROCEEDINGS RELATED TO BONNEVILLE POWER ADMINISTRATION

Petitioners in several actions in the Ninth Circuit against BPA asserted that BPA acted contrary to law 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 REP. Petitioners in several actions in the Ninth Circuit against BPA also asserted that BPA acted contrary to law in adopting or implementing the rates upon which the benefits received or to be received from BPA during the October 1, 2001 through September 30, 2006 period were based. A number of parties 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.

On May 3, 2007, the Ninth Circuit issued an opinion in *Portland Gen. Elec. v. BPA*, Case No. 01-70003, in which proceeding the actions of BPA in entering into settlement agreements regarding the REP with PSE and with other investor-owned utilities were challenged. In this opinion, the Ninth Circuit granted petitions for review and held the settlement agreements entered into between BPA and the investor-owned utilities being challenged in that proceeding to be inconsistent with statute. On May 3, 2007, the Ninth Circuit also issued an opinion in *Golden Northwest Aluminum v. BPA*, Case No. 03-73426, in which proceeding the petitioners sought review of BPA's 2002-2006 power rates. In this opinion, the Ninth Circuit granted petitions for review and held that BPA unlawfully shifted onto its preference customers the costs of its settlements with the investor-owned utilities. On October 5, 2007, petitions for rehearing of these two opinions were denied. On February 1, 2008, PSE and other utilities filed in the Supreme Court of the United States a petition for a writ of certiorari to review the decisions of the Ninth Circuit, which petition was denied in June 2008.

In May 2007, following the Ninth Circuit's issuance of these two opinions, BPA suspended payments to PSE under the amended settlement agreement (and the May 2004 agreement). On October 11, 2007, the Ninth Circuit remanded the May 2004 agreement to BPA in light of the Portland Gen. Elec. v. BPA opinion and dismissed the remaining three pending cases regarding settlement agreements.

In March 2008, BPA and PSE signed an agreement pursuant to which BPA made a payment to PSE related to the REP benefits for the fiscal year ended September 30, 2008, which payment is subject to true-up depending upon the amount of any REP benefits ultimately determined to be payable to PSE. In March and April 2008, Clatskanie People's Utility District filed petitions in the Ninth Circuit for review of BPA actions in connection with offering or entering into such agreement with PSE and similar agreements with other investor-owned utilities. Clatskanie People's Utility District asserts that BPA's actions in entering into and executing the 2008 REP agreements were contrary to law or without authority and that such agreements are null and void and result in overpayments of REP benefits to PSE and other regional investor-owned utilities.

In September 2008, BPA issued its record of decision in its reopened WP-07 rate proceeding to respond to the various Ninth Circuit opinions. In this record of decision, BPA adjusted its fiscal year 2009 rates, determined the amounts of REP benefits it considered to have been improperly paid after fiscal year 2001 to PSE and the other regional investor-owned utilities, and determined that such amounts are to be recovered through reductions in REP benefit payments to be made over a number of years. The amount determined by BPA to be recovered through reductions commencing October 2007 in REP payments for PSE's residential and small farm customers was approximately $207.2 million plus interest on unrecovered amounts to the extent that PSE receives any REP benefits for its customers in the future. However, these BPA determinations are subject to subsequent administrative and judicial review, which may alter or reverse such determinations. PSE and others, including a number of preference agency and investor-owned utility customers of BPA, in December 2008 filed petitions for review in the Ninth Circuit of various of these BPA determinations. PSE is also reviewing its options in determining if it will contest the amounts withheld as improper payments made after 2001.

In September 2008, BPA and PSE signed a short-term Residential Purchase and Sale Agreement (RPSA) under which BPA is to pay REP benefits to PSE for fiscal years ending September 30, 2009–2011. In December 2008, BPA and PSE signed another, long-term RPSA under which BPA is to pay REP benefits to PSE for the period October 2011 through September 2028. PSE and other customers of BPA in December 2008 filed petitions for review in the Ninth Circuit of the short-term and long-term RPSAs signed by PSE (and similar RPSAs signed by other investor-owned utility customers of BPA) and BPA's record of decision regarding such RPSAs. Generally, REP benefit payments under a RPSA are based on the amount, if any, by which a utility's average system cost (ASC) exceeds BPA's Preference Rate (PF) Exchange rate for such utility. The ASC for a utility is determined using an ASC methodology adopted by BPA. The ASC methodology adopted by BPA and the ASC determinations, REP overpayment determinations, and the PF Exchange rate determinations by

BPA are all subject to FERC review or judicial review or both and are subject to adjustment, which may affect the amount of REP benefits paid or to be paid by BPA to PSE. As discussed above, BPA has determined to reduce such payments based on its determination of REP benefit overpayments after fiscal year 2001.

It is not clear what impact, if any, such development or review of such BPA rates, review of such ASC, ASC methodology, and BPA determination of REP overpayments, review of such agreements, and the above described Ninth Circuit litigation may ultimately have on PSE.

# 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) 2008 QUARTER | FIRST | SECOND | THIRD | FOURTH |
|---|---|---|---|---|
| Operating revenues | $ 1,050,932 | $ 712,404 | $ 606,162 | $ 988,275 |
| Operating income | 157,868 | 86,470 | 33,474 | 104,936 |
| Net income (loss) | 79,813 | 33,654 | (8,225) | 49,687 |
| Basic earnings per common share | $ 0.62 | $ 0.26 | $ (0.06) | $ 0.38 |
| Diluted earnings per common share | $ 0.61 | $ 0.26 | $ (0.06) | $ 0.37 |

| (UNAUDITED; DOLLARS IN THOUSANDS EXCEPT PER SHARE AMOUNTS) 2007 QUARTER | FIRST | SECOND | THIRD | FOURTH |
|---|---|---|---|---|
| Operating revenues | $ 1,003,904 | $ 661,138 | $ 601,680 | $ 953,425 |
| Operating income | 158,060 | 102,048 | 54,488 | 126,438 |
| Net income | 79,061 | 38,612 | 11,394 | 55,397 |
| Basic earnings per common share | $ 0.68 | $ 0.33 | $ 0.10 | $ 0.46 |
| Diluted earnings per common share | $ 0.68 | $ 0.33 | $ 0.10 | $ 0.45 |

**PUGET SOUND ENERGY**

| (UNAUDITED; DOLLARS IN THOUSANDS) 2008 QUARTER | FIRST | SECOND | THIRD | FOURTH |
|---|---|---|---|---|
| Operating revenues | $ 1,050,932 | $ 712,404 | $ 606,162 | $ 988,275 |
| Operating income | 159,586 | 92,148 | 34,770 | 105,882 |
| Net income (loss) | 80,904 | 39,110 | (7,276) | 49,998 |

| (UNAUDITED; DOLLARS IN THOUSANDS) 2007 QUARTER | FIRST | SECOND | THIRD | FOURTH |
|---|---|---|---|---|
| Operating revenues | $ 1,003,904 | $ 661,138 | $ 601,680 | $ 953,425 |
| Operating income | 158,223 | 102,207 | 55,611 | 134,343 |
| Net income | 78,777 | 38,357 | 12,046 | 61,947 |

## 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 | 2008 | 2007 | 2006 |
|---|---|---|---|
| Equity in earnings of subsidiary | $ 162,736 | $ 191,127 | $ 177,585 |
| Other operations and maintenance | (386) | (1,206) | (1,830) |
| Merger related costs | (9,252) | (8,143) | -- |
| Other income (deductions): | | | |
| Charitable foundation contributions | -- | -- | (15,000) |
| Interest income | 863 | 1,300 | 356 |
| Interest expense | (8) | -- | -- |
| Income taxes | 976 | 1,598 | 6,202 |
| Net income from continuing operations | 154,929 | 184,676 | 167,313 |
| Equity in earnings of discontinued subsidiary | -- | (212) | 51,903 |
| Net income | $ 154,929 | $ 184,464 | $ 219,216 |
| Basic earnings per share from continuing operations | $ 1.20 | $ 1.57 | $ 1.44 |
| Discontinued operations | -- | -- | 0.45 |
| Basic earnings per share | $ 1.20 | $ 1.57 | $ 1.89 |
| Diluted earnings per share from continuing operations | $ 1.19 | $ 1.56 | $ 1.44 |
| Discontinued operations | -- | -- | 0.44 |
| Diluted earnings per share | $ 1.19 | $ 1.56 | $ 1.88 |

*See accompanying notes to the consolidated financial statements.*

*Puget Energy Condensed*

# BALANCE SHEETS

(DOLLARS IN THOUSANDS)

| AT DECEMBER 31 | 2008 | 2007 |
|---|---|---|
| Assets: | | |
| Investment in and advances to subsidiaries[1] | $ 2,249,186 | $ 2,504,091 |
| Current assets: | | |
| Cash | 57 | 24 |
| Restricted cash | -- | 3,994 |
| Receivables from affiliates | 26,092 | 15,843 |
| Prepayments and other | 545 | 545 |
| Tax receivable | 1,804 | 2,489 |
| Total current assets | 28,498 | 22,895 |
| Long-term assets: | | |
| Deferred income taxes | 674 | 3,221 |
| Other | 56 | 36 |
| Total long-term assets | 730 | 3,257 |
| Total assets | $ 2,278,414 | $ 2,530,243 |
| Capitalization and liabilities: | | |
| Common equity[1] | $ 2,273,201 | $ 2,521,954 |
| Total capitalization | $ 2,273,201 | $ 2,521,954 |
| Current liabilities: | | |
| Accounts payable | 5,213 | 878 |
| Total current liabilities | 5,213 | 878 |
| Long-term liabilities: | | |
| Other deferred credits | -- | 7,411 |
| Total long-term liabilities | -- | 7,411 |
| Total capitalization and liabilities | $ 2,278,414 | $ 2,530,243 |

[1] *In 2001 Puget Energy, Inc. was formed as a holding company over Puget Sound Energy, Inc. The common stock of Puget Sound Energy, Inc. was exchanged for the common stock for Puget Energy, Inc. The par value of Puget Sound Energy, Inc. common stock was recorded on Puget Energy, Inc.'s books at one cent per par value instead of the historical cost of Puget Sound Energy's Inc's equity. The 2007 financial statement have been revised for the additional book value of PSE.*

*See accompanying notes to the consolidated financial statements.*

*Puget Energy Condensed Statements of*

# CASH FLOWS

(DOLLARS IN THOUSANDS)

| FOR YEARS ENDED DECEMBER 31 | 2008 | 2007 | 2006 |
|---|---|---|---|
| Operating activities: | | | |
| Net income | $ 154,929 | $ 184,464 | $ 219,216 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Deferred income taxes and tax credits – net | 2,548 | 718 | (3,586) |
| Equity in earnings of discontinued subsidiary | -- | -- | (51,903) |
| Equity in earnings of subsidiary | (162,736) | (191,127) | (177,586) |
| Other | (7,332) | (1,447) | (94) |
| Dividends received from subsidiaries | 145,840 | 108,434 | 109,782 |
| (Increase) decrease in accounts receivable | 38 | 279 | (355) |
| (Increase) decrease in tax receivable | 810 | (2,101) | (388) |
| Increase (decrease) in accounts payable | 1,946 | (10) | 325 |
| Increase (decrease) in affiliated payables | -- | 563 | (5,427) |
| Decrease in accrued tax payable | -- | -- | (960) |
| Decrease in accrued expenses and other | -- | (531) | (4,763) |
| Net cash provided by operating activities | 136,043 | 99,242 | 84,261 |
| Investing activities: | | | |
| Cash proceeds from sale of InfrastruX | -- | -- | 275,000 |
| (Increase) decrease in restricted cash | 3,994 | (181) | (3,813) |
| Investment in subsidiaries | -- | (297,073) | (70,114) |
| (Increase) decrease in loan to subsidiaries | (10,287) | 8,537 | (24,303) |
| Net cash provided (used) by investing activities | (6,293) | (288,717) | 176,770 |
| Financing activities: | | | |
| Dividends paid | (129,677) | (108,434) | (104,332) |
| Common stock issued | -- | 300,544 | 5,877 |
| Long-term debt and lease payment | -- | -- | (151,849) |
| Payments made to minority interest | -- | -- | (10,451) |
| Issue costs of stocks | (40) | (2,636) | (252) |
| Net cash provided (used) by financing activities | (129,717) | 189,474 | (261,007) |
| Increase (decrease) in cash | 33 | (1) | 24 |
| Cash at beginning of year | 24 | 25 | 1 |
| Cash at end of year | $ 57 | $ 24 | $ 25 |

*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, 2008 | | | | |
| Accounts deducted from assets on balance sheet: | | | | |
| Allowance for doubtful accounts receivable | $ 5,465 | $ 13,126 | $ 12,199 | $ 6,392 |
| YEAR ENDED DECEMBER 31, 2007 | | | | |
| Accounts deducted from assets on balance sheet: | | | | |
| Allowance for doubtful accounts receivable | $ 2,762 | $ 13,019 | $ 10,316 | $ 5,465 |
| 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 |
| Deferred tax asset valuation allowance | 16,075 | -- | 16,075 | -- |

| **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, 2008 | | | | |
| Accounts deducted from assets on balance sheet: | | | | |
| Allowance for doubtful accounts receivable | $ 5,465 | $ 13,126 | $ 12,199 | $ 6,392 |
| YEAR ENDED DECEMBER 31, 2007 | | | | |
| Accounts deducted from assets on balance sheet: | | | | |
| Allowance for doubtful accounts receivable | $ 2,762 | $ 13,019 | $ 10,316 | $ 5,465 |
| 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 |

## 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 Executive Vice President 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, 2008, the end of the period covered by this report. Based upon that evaluation, the President and Chief Executive Officer and Executive Vice President 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, 2008 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 Executive Vice President 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, 2008.

Puget Energy's effectiveness of internal control over financial reporting as of December 31, 2008, 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 Executive Vice President 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, 2008, the end of the period covered by this report. Based upon that evaluation, the President and Chief Executive Officer and Executive Vice President 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, 2008, 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 Executive Vice President 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, 2008.

PSE's effectiveness of internal control over financial reporting as of December 31, 2008 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 OFFICERS AND CORPORATE GOVERNANCE

**BOARD OF DIRECTORS**

Ten directors currently constitute Puget Energy's Board of Directors and eleven directors currently constitute PSE's Board of Directors, as set forth below.

**William S. Ayer**, age 54, is a director on the boards of both Puget Energy and PSE. Mr. Ayer has been Chairman, President and Chief Executive Officer Alaska Air Group (air transportation) since 2003. He is also Chairman and Chief Executive Officer of Alaska Airlines, Inc. since 2008. He served as Alaska Airlines' Chairman, President and Chief Executive Officers from 2003 to 2008, Chief Executive Officer from 2002 to 2003, and President and Chief Operating Officer from 1997 to 2002. Mr. Ayer has been a director of Puget Energy and PSE since 2005. Mr. Ayer also serves on the board of the Seattle Branch, Federal Reserve Bank of San Francisco.

**Graeme Bevans**, age 51, is a director on the boards of both Puget Energy and PSE. Mr. Bevans is currently Vice President and Head of Infrastructure at CPP Investment Board, which position he has held since 2006. Prior to joining CPP Investment Board, Mr. Bevans served as Senior Investment Manager - Infrastructure at Industry Funds Management in Melbourne, Australia from 2002 to 2006. Mr. Bevans is currently a director on the board of Anglian Water Group, a United Kingdom water/waste-water company and Doowron PTY LTD, a private Australian company.

**Andrew Chapman**, age 53, is a director on the boards of both Puget Energy and PSE. Mr. Chapman is currently a Managing Director in the Macquarie Capital Funds division of the Macquarie Group, which position he has held since 2006. Prior to joining the Macquarie Group, Mr. Chapman was Vice President – Strategy & Regulation for American Water from 2005 to 2006 and Regional Managing Director from 2003 to 2004.

**Alan James**, age 55, is a director on the boards of both Puget Energy and PSE. Mr. James is currently the Senior Managing Director of Macquarie Capital (USA) Inc., which position he has held since 2005. Prior to that time, Mr. James was Managing Director and Head, Investment Banking Australia and New Zealand at Citigroup from 2002 to 2005.

**Alan Kadic**, age 37, is a director on the boards of both Puget Energy and PSE. Mr. Kadic is currently a Senior Principal in the Infrastructure Group of the Private Investments department at the Canada Pension Plan Investment Board, which position he has held since 2007. Prior to joining CPP Investment Board, Mr. Kadic served as Vice President at Macquarie

Bank Limited in Toronto, Canada from 2004 to 2007. Mr. Kadic is currently a director on the board of Wales and West Utilities, a United Kingdom natural gas distribution company.

**Christopher Leslie**, age 44, is a director on the boards of both Puget Energy and PSE. Mr. Leslie is currently the Executive Director in the Macquarie Capital Funds division of the Macquarie Group, which position he has held since 2005 and has also served as the Chief Executive Officer of Macquarie Infrastructure Partners I and II since 2006. Mr. Leslie served as Executive Director of Macquarie Bank Limited from 2004 to 2005. Mr. Leslie is currently a director on the boards of Duquesne Light Holdings, Inc. and Duquesne Light Company.

**William McKenzie**, age 52, is a director on the boards of both Puget Energy and PSE. Mr. McKenzie has been Senior Vice President - Infrastructure and Timber Investments for Alberta Investment Management Corporation since December 2008. He served as Head, Infrastructure and Timber Investments from 2005 to 2008 and Senior Portfolio Manager, Infrastructure and Timber Investments from 2005 to 2008. Prior to that time, Mr. McKenzie was Managing Director for VectorWest Growth Capital in 2004.

**Stephen P. Reynolds**, age 61, is a director on the boards of both Puget Energy and PSE. Mr. Reynolds has been President and Chief Executive Officer since February 6, 2009. Prior to February 6, 2009, Mr. Reynolds was Chairman, President and Chief Executive Officer of Puget Energy and PSE since May 2005, and was President and Chief Executive Officer from January 2002 to April 2005. Mr. Reynolds has been a director of Puget Energy and PSE since 2002. Mr. Reynolds also serves as a director of Intermec, Inc. and Green Diamond Resources Company.

**Herbert B. Simon**, age 65, is a director only on the board of PSE. Mr. Simon has been a member of Simon Johnson, L.L.C. (real estate and venture capital projects investment company located in Tacoma, Washington) and its predecessor company since 1985. Mr. Simon has served as a director of Puget Energy and PSE since March 2006. In addition, Mr. Simon serves as a Regent of the University of Washington.

**Lincoln Webb**, age 37, is a director on the boards of both Puget Energy and PSE. Mr. Webb is currently the Vice President of the Private Placements group at British Columbia Investment Management Corporation (or bcIMC), which position he has held since 2005. He also served as Portfolio Manager from 2004 to 2005. Mr. Webb currently serves as a director on the Corix group of companies.

**Mark Wong**, age 36, is a director on the boards of both Puget Energy and PSE. Mr. Wong is currently the Executive Director in the Macquarie Capital Funds division of the Macquarie Group, which position he has held since 2008 and serves as the Chief Financial Officer and Treasurer of Macquarie Infrastructure Partners I and II, which positions he has held since 2006. Mr. Wong also served as Chief Executive Officer and Secretary of Macquarie Canadian Infrastructure Limited from 2004 to 2005.

### EXECUTIVE OFFICERS

The information required by this item with respect to Puget Energy and PSE is incorporated herein by reference to the material under "Executive Officers of the Registrants" in Part I of this report.

### AUDIT COMMITTEE

The Puget Energy and PSE Boards of Directors have both established an Audit Committee. Directors Andrew Chapman, Alan Kadic, William McKenzie and William S. Ayer are the members of the Audit Committee. Puget Energy and PSE currently do not have any outstanding stock listed on a national securities exchange and therefore, there are no independence standards applicable to either company in connection with the independence of its Audit Committee members.

### CHANGES TO THE PROCEDURES BY WHICH SHAREHOLDERS MAY RECOMMEND NOMINEES TO THE BOARD OF DIRECTORS

Following the closing of the merger, members of the Boards of Directors of Puget Energy and PSE are nominated and elected in accordance with the provisions of their respective Amended and Restated Bylaws.

### CODE OF ETHICS

Puget Energy and PSE have adopted a Corporate Ethics and Compliance Code applicable to all directors, officers and employees and a Code of Ethics applicable to the Chief Executive Officer and senior financial officers, which are available on the website www.pugetenergy.com. If any material provisions of the Corporate Ethics and Compliance Code or the Code of Ethics are waived for the Chief Executive Officer or senior financial officers, or if any substantive changes are made to either code as they relate to any director or executive officer, we will disclose that fact on our website within four business days. In addition, any other material amendments of these codes will be disclosed.

### COMMUNICATIONS WITH THE BOARD

Interested parties may communicate with an individual director or the Board of Directors as a group via U.S. Postal mail directed to: Chairman of the Board of Directors, c/o Corporate Secretary, Puget Energy, Inc., P.O. Box 97034, PSE-12, Bellevue, Washington 98009-9734. Please clearly specify in each communication the applicable addressee or addressees you wish to contact. All such communications will be forwarded to the intended director or Board as a whole, as applicable.

### SECTION 16(A) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Prior to the closing of the merger on February 6, 2009, Section 16(a) of the Securities Exchange Act of 1934 required the directors and officers of Puget Energy to file reports of ownership and changes in ownership with respect to the equity securities of Puget Energy with the SEC. To Puget Energy's knowledge, based on our review of the reports furnished to Puget Energy in 2008 and written representations that no other reports were required, all directors and officers of Puget Energy who are subject to the Section 16 reporting requirements filed the required reports on a timely basis in 2008.

## ITEM 11. EXECUTIVE COMPENSATION

### PUGET ENERGY
### PUGET SOUND ENERGY
### EXECUTIVE COMPENSATION

### COMPENSATION AND LEADERSHIP DEVELOPMENT COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

The members of the Compensation and Leadership Development Committees (referred to as the Committee) of the Boards of Directors (referred to as the Board) of Puget Energy and Puget Sound Energy (referred to as the Company) who served during 2008 are named in the Compensation and Leadership Development Committee Report on page 154. No members of the Committee were officers or employees of the Company or any of its subsidiaries during 2008, were formerly Company officers or had any relationship otherwise requiring disclosure. Effective with the completion of the Company's merger on February 6, 2009, a new Board and Committee were appointed.

### COMPENSATION DISCUSSION AND ANALYSIS

This section provides information about the compensation program in place for the Company's Named Executive Officers who are included in the Summary Compensation Table on page 155 — the Chief Executive Officer (CEO), the Chief Financial Officer and the three other most highly compensated executive officers for 2008. It includes a discussion and analysis of the overall objectives of our compensation program and each element of compensation the Company provides.

### COMPENSATION PROGRAM OBJECTIVES

The Company's executive compensation program has two main objectives:

- Support sustained Company performance by having talented people running the business.
- Align compensation payment levels with achievement of Company goals.

The following is a discussion of the specific strategies used in 2008 to accomplish each of these objectives by the Committee and management to implement these strategies.

1. Our objective of supporting sustained Company performance by having talented people running the business is supported by the following strategies:

- *Designing and delivering compensation programs that attract, motivate, and retain a talented executive team.*

Several factors are critical to attracting and retaining executives for the Company. One is ensuring that total pay opportunity is competitive with similar companies so that new executives will want to join the Company and current executives are not hired away. As described below in the discussion of Compensation Program Elements (Review of Pay Element Competitiveness), the Committee annually compares executive pay to external market data from similar companies in our industry. Base pay and total direct compensation (which is base salary plus annual and long-term incentive pay) are targeted to the 50th percentile of our comparator group. Individual pay adjustments are reviewed to see how they position the executive in relation to the median of market pay, while also considering the executive's recent performance and experience level. The Company may choose to pay an individual above or below the median level of market pay when our executive has a role with greater or lesser responsibility than the best comparison job or when our executive's experience and performance exceed those typically found in the market. In 2008, the Committee determined the pay level for Mr. Reynolds, the President and CEO, and reviewed and approved Mr. Reynolds' recommendations for pay levels of the other executives.

Another factor critical to motivating our executives, as well as attracting and retaining them, is to provide incentive compensation for meeting and exceeding target levels of annual and long-term goals. By establishing goals, monitoring results, and providing payments and recognition for accomplishment of results, the Company focuses executives on actions that will improve the Company and enhance investor value, while also retaining key talent.

A final critical factor in attracting, motivating and retaining executives is to provide them with retirement income. We recognize that executives choose to work for the Company from a variety of other alternative organizations, and one financial goal of employees is to provide a secure future for themselves and their families. The Committee reviews the design of retirement programs provided by the comparator group and provides benefits that are commensurate with this group.

- *Designing and delivering incentive programs that support the Company's business direction as approved by the Board of Directors and align executive interests with those of investors and customers.*

In addition to rewarding performance that meets or exceeds goals, our annual and long-term incentives help executives focus on the priorities of our investors and customers. Both the annual incentive plan and the long-term incentive plan measure and reward the Company's performance on Service Quality Indices (SQIs). These reporting measures were developed in collaboration with the Company's regulator and provide customers with a report card on the Company's customer service and reliability. In fact, we provide an annual accounting on these 11 measures to our customers each year. Additional key measures used in 2008 for determining incentives were Earnings Per Share (EPS) in the annual incentive plan and Relative Total Shareholder Return (TSR) in the long-term incentive plan. EPS and Relative TSR were important shareholder performance measures, but they also indicated to our customers that the Company will have the financial strength needed for long-term sustainability.

The Committee evaluates the performance factors and targets for its annual and long-term incentive programs each year. The Committee believes the balance between annual and long-term incentives and the performance targets based on management's operating plan, which includes providing good customer service, do not provide an incentive to executives to take unreasonable risks relating to the Company's business.

- *Executing the Company's succession planning process to ensure that executive leadership continues uninterrupted by executive retirements or other personnel changes.*

The President and CEO leads the talent reviews and executive succession planning through meetings with his executive team. Each executive conducts talent reviews of senior employees who have high potential for assuming greater responsibility in the Company. The talent reviews include evaluations prepared within the Company and by external organizational development consultants. The Committee annually reviews these assessments of executive readiness, the plans for development of the Company's key executives, and progress made on these succession plans. The Committee directly participates in discussion of succession plans for the position of President and CEO.

2. Our objective of aligning compensation payment levels with achievement of Company goals is supported by the following strategy:

- *Placing a significant portion of each executive's total direct compensation at risk to align executive compensation with financial and operating performance. Total direct compensation is base salary plus annual and long-term incentive pay, and does not include retirement plan accruals.*

When Company results are above expectations, total direct compensation is higher than our target of the 50th percentile of our comparator group. If results are below expectations, total direct compensation is lower than this targeted level. As described above as "pay for performance," the Company's variable pay program helps focus executives and creates a record of their results.

**COMPENSATION PROGRAM ELEMENTS**

This section continues the detailed discussion of the Company's compensation program by identifying the elements of the program and examining how these elements function and why the Committee chooses to include the items in the compensation program.

The Company's compensation policies encompass a mix of base salary, annual and long-term incentive compensation, health and welfare benefits, retirement programs, and a small number of perquisites. The Company also provides certain change in control benefits to executives. The total package is designed to provide participants with appropriate incentives that are competitive with the comparator group and achieve current operational performance and customer service goals as well as the long-term objective of enhancing investor value. The Company does not have a specific policy regarding the mix of cash and non-cash compensation elements, but arrives at a mix of pay by setting each compensation element relative to market comparators. The Company delivered compensation in 2008 through cash and stock-based programs, because cash provides liquidity for employees while stock increased the connection to shareholders. Long-term performance-based incentives are designed to comprise the largest portion of each executive's incentive pay. Annually the Committee reviews total compensation opportunity and actual total compensation received over the prior years by each officer in the form of a tally sheet. This review helps inform the Committee's decisions on program designs by allowing the Committee to review overall pay received in relation to Company results.

***Review of Pay Element Competitiveness***

In making compensation decisions on base salary and annual and long-term incentive programs, management prepares comprehensive surveys of pay for review by the Committee and the Committee's outside executive pay consultant, Towers Perrin. The surveys summarize data provided by the Towers Perrin 2007 Energy Services survey for a selection of utility and other companies that are most similar in scope and size to Puget Energy. For the review of compensation pay levels and practices in 2008, we included the following utility companies in our comparator group that were all of similar scope (generally $1.5 billion — $6.0 billion revenue and $4.0 billion — $11.0 billion asset size) and also participated in the Towers Perrin 2007 Energy Services survey:

1. Allegheny Energy
2. Alliant Energy
3. Ameren
4. Atmos Energy
5. Avista
6. Great Plains Energy
7. MDU Resources
8. NSTAR
9. New York Power Authority
10. Nicor
11. OGE Energy
12. PNM Resources
13. Pinnacle West Capital
14. Portland General Electric
15. SCANA
16. Westar Energy
17. Wisconsin Energy

***Base Salary***

Base salaries are generally targeted at the 50th percentile for the comparator group. Actual salaries vary by individual and depend on additional factors, such as expertise, individual performance achievement, level of experience and level of contribution relative to others in the organization.

Generally, base salaries for executives are administered on an individual basis by the Committee using as a guideline, median salary levels of our comparator group companies, as well as internal pay equity among executives. We recognize that it is necessary to provide executives with a portion of total compensation that is delivered each month and provides a balance to other pay elements that are at risk.

***Base Salary Adjustments***

The Committee reviewed Mr. Reynolds' performance and, based on his results and market comparison, his base salary for 2008 was increased from $800,000 per year to $825,000, a 3.1% increase. For the other Named Executive Officers, Mr. Reynolds evaluated their performance during 2007 and recommended increases to the Committee based on individual performance. Additionally, based on market data and internal peer comparisons, the base salaries for Mr. Markell and Ms. Harris were determined to be below market median and each of their salaries was increased to $360,000, a 20% increase. The recommended increases for the other executives were similar to the range of salary increases awarded to all employees. The Committee reviewed market comparisons and found the proposed increases appropriate. These increases were: Mr. Valdman, a 5.3% increase to $395,000; and Ms. O'Connor, a 3.5% increase to $310,500.

***Annual Incentive Compensation***

In addition to reviewing base salaries paid by our market comparator group, we also review annual incentive payments through an annual review of total cash compensation (base salaries plus incentives). Total cash compensation is targeted at the 50th percentile of total cash compensation for the industry comparator group if the Company's annual performance goals are achieved at target. If performance goals significantly exceed target, total cash compensation can approach the 75th percentile.

All PSE employees, including executive officers, participate in an annual incentive program referred to as the "Goals and Incentive Plan." The plan is designed to provide financial incentives to executives for achieving desired annual operating results while meeting the Company's service quality commitment to customers. The Company's service quality commitment is measured by performance against 11 SQIs covering three broad categories, set forth below. These are the same SQIs for which the company is accountable to the Washington Commission. Based on a recent order from the Washington Commission, the "overall customer satisfaction" SQI will be eliminated in 2009. The remaining ten SQIs will continue to be key performance measurements for the Company.

- **Customer Satisfaction**
  - Overall customer satisfaction (a measure in 2008, but no longer a measure in 2009), customer access center, gas field services and Washington Commission complaints
- **Customer Service**
  - Calls answered "live", on-time appointments and disconnects for non-pay
- **Safety and Reliability**
  - Gas emergency response, electric emergency response, non-storm outage frequency and non-storm outage duration

The 2008 plan had a funding level based on EPS and attainment of SQIs as shown in the table below. The Committee can adjust EPS used in the annual incentive calculation to exclude nonrecurring items that are outside the normal course of business for the year, but did not do so for 2008. Individual awards were based on performance against team and individual goals. Individual goals were developed from the overall corporate goals for 2008:

- **Enhance Customer Service** — Provide responsive service to our customers by listening, leveraging new systems, updating processes and providing new and improved products.
- **Optimize Generation and Delivery** — Manage existing resources as well as acquire, build and/or replace infrastructure in responsible ways that meet customers' needs, protect the environment and provide a fair return to investors.
- **Be a Good Neighbor** — Demonstrate that we accept leadership to protect and improve our natural gas and electric service, energy efficiency initiatives, corporate giving and community involvement.
- **Value Employees** — Focus on safety, teamwork, process improvement, and technology as well as employee development and recognition to make PSE truly a great place to work.

- **Own it** — Each employee must manage the resources under their control as if they owned them.
- **Continue to Learn and Grow** — Examine past practices and apply lessons learned to develop and implement solutions that add value and enhance customer service and community involvement.

**ANNUAL INCENTIVE PERFORMANCE PAYOUT SCALE**

| PERFORMANCE | 2008 EPS | SQI* | FUNDING LEVEL |
|---|---|---|---|
| Maximum | $1.55 | 11/11 | 240% |
| Target | 1.20 | 10/11 | 100% |
| Trigger Payout Funding | 1.15 | 10/11 | 50% |
| 2008 Actual Performance | $1.25 | 9/11 | 112.5% |

* SQI results of 5/11 or better required for any incentive payout funding. SQI results below 10/11 reduce funding (e.g., 9/11 = 90%, 8/11 = 80%, etc.).

Actual performance for 2008 was better than the target level for EPS, but below target for SQI achievement. Puget Sound Energy EPS was $1.25, and SQI achievement was 9 out of 11, leading to a funding level of 112.5% (125% x 90% = 112.5%).

For 2008, the target incentives for this plan varied by executive officer as shown in the table below. The maximum incentive for exceptional performance in this plan is twice the target incentive. After considering performance on individual and team goals, which were met by each executive officer, no adjustments were made and the following amounts were paid at 112.5% of target:

| NAME | TARGET INCENTIVE (% OF BASE SALARY) | 2008 ACTUAL INCENTIVE PAID |
|---|---|---|
| Stephen P. Reynolds | 85% | $788,906 |
| Bertrand A. Valdman | 60% | 266,625 |
| Eric M. Markell | 60% | 243,000 |
| Kimberly J. Harris | 60% | 243,000 |
| Jennifer L. O’Connor | 50% | 174,656 |

***Long-Term Incentive Compensation***

Total direct compensation (base salary, annual incentive and long-term incentives) opportunities are designed to be competitive with market practices, generally targeting the 50th percentile of the comparator group for performance at target. The Puget Energy 2005 Long-Term Incentive Plan (LTIP), approved by shareholders in 2005, provides for several forms of multi-year incentive grants, both equity and cash-based awards. Even though the LTIP provides many types of awards, through 2008 the Company’s use of the plan has typically been limited to two types of grants to executives and key employees — (i) annual grants comprised of a mixture of Performance Shares and Performance-Based Restricted Stock and (ii) new employment grants to newly hired executives. The Company has not used stock options frequently, even though permitted under the LTIP, because the Committee believes that Performance Shares and Performance-Based Restricted Stock generally have better incentive value for executives in a utility industry company.

The table below shows the mix of Performance Shares and Performance-Based Restricted Stock grants under the LTIP for each three-year cycle that was active in 2008. Beginning with the 2006-2008 grant cycle, the committee began granting a combination of Performance Shares and Performance-Based Restricted Stock. The committee adopted a mix for grants of 50% each for executive officers, except the CEO is granted 70% Performance Shares and 30% Performance-Based Restricted Stock to better align the CEO's pay at risk with the overall Company performance.

| Grant Cycle | Performance Shares | Performance Based Restricted Stock |
|---|---|---|
| 2006-2008* | 50% | 50% |
| 2007-2009* | 50% | 50% |
| 2008-2010* | 50% | 50% |

* *CEO grants are split 70% Performance Shares and 30% Performance-Based Restricted Stock*

The Committee established the number of LTIP shares for each executive by evaluating the actual payment and forecast target payment of long-term incentive awards of our market comparator group for comparable levels of responsibility. The Committee generally did not consider previously granted awards or the level of accrued value from prior programs when granting annual incentive awards or making new LTIP grants. Each year's grant is primarily viewed in the context of the compensation opportunity needed to maintain the Company's competitive position relative to the comparator group. In 2008 and previously, target LTIP awards were calculated based on a percentage of annual salary, and were then translated into a target number of shares using the average of the month ending stock prices from the three months prior to the start of the performance cycle. Targets for 2008 were 170% of base salary for Mr. Reynolds; 110% for Mr. Valdman, Mr. Markell and Ms. Harris; and 95% for Ms. O'Connor. Beginning in 2009, LTIP awards will be calculated based on a percentage of annual salary and have a cash target.

The points below summarize the performance measures and design of the LTIP grants that were outstanding during 2008.

Performance Shares:

- A Performance Share grant establishes a target number of shares of stock that will be paid to the participant if the Company achieves the targeted level of performance during the three-year performance cycle. The actual award paid is based on Company performance relative to target, subject to a minimum threshold level of performance.
- The Performance Share grant is calculated based on Puget Energy's total shareholder return relative to the EEI Combination Gas & Electric Investor Owned Utilities Index and performance outcomes based on the same SQIs used under the annual incentive plan described above. The grant requires a threshold performance of relative total shareholder return at the 25th percentile, and pays at target level if total shareholder return is at the 50th percentile and 10 out of 11 SQIs are met.
- At the completion of the performance cycle, if the Performance Share grant is paid, the participant receives shares of stock and a cash payment equivalent to the dividends that would have been paid on this number of shares during the performance cycle.
- Participants who are meeting or exceeding shareholder ownership guidelines may elect to receive up to 50% of the value of the Performance Shares in cash.
- The Performance Shares have interim calculations ("banking") at the end of Year 1 for 15% of the shares, at the end of Year 2 for 25%, and at the conclusion of the performance period in Year 3 for the remaining 60% of the shares. If the full three-year performance is higher than the performance banked, the full award amount is paid.

Performance-Based Restricted Stock:

- A Performance-Based Restricted Stock grant is a grant of shares that vest based on a combination of continued service and attainment of Company performance. The Performance-Based Restricted Stock vests in installments over a three-year period only if a target number of SQIs are met and the participant remains employed with the Company.
- Vesting is based on the Company meeting or exceeding 8 out of 11 SQIs in each year of the three-year period and the participant continuing employment through the vesting dates at the end of Year 1 (15% vesting), Year 1 (25% vesting) and Year 3 (60% vesting).

LTIP Performance:

In connection with the completion of the merger on February 6, 2009, all LTIP Awards were settled in cash, and the amounts received by each Named Executive Officer for the 2007-2009 and 2008-2010 Awards are included in "Payments Upon Completion of the Merger."

- 2006-2008 Grant: Overall performance on the cumulative grant for the three-year period was 149.5% of the target grant. Performance on relative TSR was 94th percentile versus the comparator group and the service quality measures achieved 90% of target. The Performance Share grant had a performance banking of 16.1% in 2006 and 35.2% in 2007, which is included in the 149.5%. The Committee approved the 2006-2008 performance measures just prior to the merger close, and the awards were paid in cash after the close.
- 2007-2009 Grant: Overall performance on the cumulative grant for the first two years was 149.5% of the target grant. Performance on relative TSR was 100th percentile versus the comparator group and the service quality measures achieved 90% of target. The Performance Share grant had a performance banking of 21.1% in 2007 and 37.4% in 2008, which is included in the 149.5%. With the Company's merger, these awards accelerated and were paid in cash.
- 2008-2010 Grant: Overall performance for the first year of this grant was 149.5% of the target grant. Performance on relative TSR was at the 86th percentile versus the comparator group and the service quality measures achieved 90% of target. The Performance Share grant had a performance share banking of 22.4% for the first year, which is included in the 149.5%. With the Company's merger, these awards accelerated and were paid in cash.

Previously, new employment grants, usually in the form of restricted stock, performance shares, or in one case, non-qualified stock options, were made to attract an executive to the Company, often to replace value the candidate would forfeit from similar awards by moving to the Company.

***Timing of Grants***

The Committee approves LTIP grants in the first quarter of the year at the regular meeting of the Committee, which typically is within a month after the Company has publicly released a report of its annual earnings. Due to administrative requirements, the Committee may make the effective date of grants up to five business days after the date of Committee action.

***Stock Ownership***

The Company has established stock ownership guidelines to be achieved over a five-year period for PSE officers and key managers. For executives, holding a certain amount of stock relative to their current income helps to strengthen their alignment to shareholders. The guidelines range from five times base salary for the President and CEO to two times base salary for the other Named Executive Officers to 50% of base salary for other key employees. Directly owned shares, share equivalents in the deferred compensation plan, and contingent shares in the LTIP that are forecast to be paid, count towards meeting the stock ownership guidelines. The Company has determined that as of December 31, 2008, all of the Named Executive Officers met or exceeded their guidelines. Officers and directors of the Company are not allowed to own derivatives of Puget Energy stock, nor are they allowed to own shares in margin accounts. Effective with the delisting of Puget Energy stock on February 6, 2009, stock ownership guidelines are no longer pertinent and have been eliminated.

***Impact of Accounting and Tax Treatment of Compensation***

The accounting treatment of compensation generally has not been a factor in determining the amounts of compensation for our executive officers. However, the Company considers the accounting impact of various program designs to balance the potential cost to the Company with the benefit/value to the executive. The Company considers the tax impact of long-term incentive compensation awards, and therefore to the extent practical, strives to deliver pay that qualifies under IRS Section 162(m) as performance-based to obtain a corporate tax deduction. Under Section 162(m), the Company may not deduct compensation expense for the Named Executive Officers (other than the Chief Financial Officer) if that expense is over one million dollars, except that performance-based pay is excluded from the total pay subject to the Section 162(m) deduction limit. Our LTIP grants of multi-year cash incentives, Performance-Based Restricted Stock and Performance Shares are designed to meet the performance-based qualification requirements and be fully tax deductible. Only Mr. Reynolds has pay that normally exceeds the one million dollar level, and the majority of this pay is performance-based and qualifies for deduction under Section 162(m). The Committee has the right under the LTIP to exercise its discretion to decrease, but not to increase, the payment amount of LTIP awards from the grant's performance-based calculation.

***Retirement Plans — Supplemental Executive Retirement Plan (SERP)***

The Company maintains the SERP for executives to provide a benefit that is coordinated with the tax-qualified PSE Retirement Plan (Retirement Plan). Without the addition of the SERP, these executives would receive lower percentages of replacement income during retirement than other employees. All the Named Executive Officers except Mr. Reynolds participate in the SERP. When Mr. Reynolds was hired, he elected to receive an annual contribution to his account in the Deferred Compensation Plan for Key Employees in lieu of participating in the SERP, as described in the following paragraph. He participates in the Retirement Plan. Additional information regarding the Retirement Plan and the SERP is shown in the "2008 Pension Benefits" table.

***Retirement Plans — Deferred Compensation Plan for Key Employees (Deferred Compensation Plan)***

The Named Executive Officers are eligible to participate in the Deferred Compensation Plan. The Deferred Compensation Plan provides executives an opportunity to defer up to 100% of base salary, annual incentive bonus and vested performance shares, plus receive additional Company contributions made by PSE, into an account with four investment tracking fund choices. The funds mirror performance in major asset classes of bonds, stocks, Puget Energy stock (until the delisting of Puget Energy stock), and an interest crediting fund that changes rate quarterly based on corporate bond rates. Similar to the SERP, the Deferred Compensation Plan is intended to allow the executives to defer current income, without being limited by the Internal Revenue Code contribution limitations for 401(k) plans and therefore have a deferral opportunity similar to other employees. The Company contributions are also intended to restore benefits not available to executives under PSE's tax-qualified plans due to Internal Revenue Code limitations on compensation and benefits applicable to those plans. Mr. Reynolds additionally receives an annual Company contribution to his Deferred Compensation Plan account equal to 15% of the base salary and annual incentive payment he received during the prior year. This account is a feature of Mr. Reynolds' employment agreement. Additional information regarding the Deferred Compensation Plan and Mr. Reynolds' employment agreement arrangement, as well as his year-end balance, is shown in the "2008 Nonqualified Deferred Compensation" table.

***Post-Termination Benefits***

The Company provides change in control agreements to its executive officers, including the Named Executive Officers, to establish in advance the terms of payments if the Company should have a change in control. Change in control agreements are important for two primary reasons. First, many executives when joining a new company require a level of assurance that they will receive pay in the event of a change in control after they join the company. Secondly, the Company provides change in control agreements so that the executives are focused on the Company's ongoing operations and not distracted by the employment uncertainty that can arise in the event of a change in control.

The Committee periodically reviews existing change in control arrangements for the comparator group considering benchmarking information provided by Towers Perrin. Based on this information, the Committee believes that the arrangements generally provide benefits that are similar to those of the comparator group. The change in control agreements call for accelerated vesting of equity awards in the event of a change in control, meaning that executives will receive accelerated vesting even if their employment continues with the Company or a successor company. Payment of severance benefits, however, requires a "double trigger" of both a change in control and the executive not continuing employment with the Company or a successor company, except Mr. Reynolds' employment agreement provides that payment of change in control benefits will be made at the time of a change in control even if employment continues with the Company or a successor company.

The "Potential Payments Upon Termination or Change in Control" section describes the existing change in control agreements with the Named Executive Officers as well as other plans and arrangements that would provide benefits on termination of employment, and the estimated potential incremental payments upon termination or a change in control based on an assumed termination or change in control date of December 31, 2008.

The Company's merger, which was completed on February 6, 2009, was a change in control event under the Company's change in control agreements and arrangements that resulted in the payment to each Named Executive Officer of the amounts included in "Payments Upon Completion of the Merger."

***Other Compensation***

In addition to base salary and annual and long-term incentive award opportunities, the Company also provides the Named Executive Officers with benefits and perquisites targeted to competitive practices. The executives participate in the same group health and welfare plans as other employees. Company vice presidents and above, including the executives, are eligible for additional disability and life insurance benefits. The executives are also eligible to receive reimbursement for financial planning, tax preparation, and legal services, business club memberships and executive physicals. The reimbursement for financial planning, tax preparation and legal services is provided to allow executives to concentrate on their business responsibilities. Business club memberships are provided to allow access for business meetings and business events at club facilities and executives are required to reimburse the Company for individual use of club facilities. Perquisites do not make up a significant portion of executive compensation, amounting to less than $10,000 in total for each executive in 2008.

***Relationship Among Compensation Elements***

A number of compensation elements increase in absolute dollar value as a result of increases to other elements. Base salary increases translate into higher dollar value incentive opportunity for annual and long-term incentives, because each plan operates with a target level award set as a percentage of base salary. Base salary increases also increase the level of retirement benefits, as do actual annual incentive plan payments. Some key compensation elements are excluded from consideration when determining other elements of pay. Retirement benefits exclude LTIP payments in the calculation of qualified retirement (pension and 401(k)) and SERP benefits.

## COMPENSATION AND LEADERSHIP DEVELOPMENT COMMITTEE REPORT

The Board delegates responsibility to the Compensation and Leadership Development Committee to establish and oversee the Company's executive compensation program. During 2008 and through February 6, 2009, each member of the Committee meets the independence requirements of the SEC and the NYSE.

The individuals listed below, who were the members of the Company's Compensation Committee throughout 2008 and up until the effective date of the merger on February 6, 2009, have reviewed and discussed the "Compensation Discussion and Analysis" with the Company's management. Based on this review and discussion, the Committee recommended to the current Board, and the current Board has approved, that the "Compensation Discussion and Analysis" be included in the Company's Annual Report on Form 10-K for the year ended December 31, 2008 for filing with the SEC.

Compensation and Leadership
Development Committee of
Puget Energy, Inc.
Puget Sound Energy, Inc.
(2008 and through February 6, 2009)

Stephen E. Frank, Chair
William S. Ayer
Herbert B. Simon

## SUMMARY COMPENSATION TABLE

The following information is furnished for the year ended December 31, 2008 with respect to the "Named Executive Officers" during 2008. The positions and offices below are at Puget Energy and PSE, except that Mr. Valdman and Ms. Harris are officers of PSE only. Salary compensation includes amounts deferred at the executive's election.

| NAME AND PRINCIPAL POSITION | YEAR | SALARY ($) | BONUS ($) | STOCK AWARDS ($)[1] | OPTION AWARDS ($)[1] | NON-EQUITY INCENTIVE PLAN COMPENSATION ($)[2] | CHANGE IN PENSION VALUE AND NONQUALIFIED DEFERRED COMPENSATION EARNINGS ($)[3] | ALL OTHER COMPENSATION ($)[4] | TOTAL ($) |
|---|---|---|---|---|---|---|---|---|---|
| Stephen P. Reynolds | 2008 | $819,792 | $ -- | $2,274,203 | $ -- | $788,906 | $29,910 | $ 316,124 | $4,228,935 |
| President and Chief | 2007 | 794,896 | -- | 2,949,696 | -- | 722,160 | 20,328 | 330,647 | 4,817,727 |
| Executive Officer | 2006 | 769,901 | -- | 1,757,969 | 99,793 | 614,672 | 28,882 | 277,221 | 3,548,438 |
| Bertrand A. Valdman | 2008 | $390,836 | $ -- | $ 588,809 | $ -- | $266,625 | $136,157 | $ 47,660 | $1,430,087 |
| Executive Vice President | 2007 | 372,754 | -- | 747,622 | -- | 238,950 | 107,558 | 48,111 | 1,514,995 |
| and Chief Operating Officer | 2006 | 361,142 | -- | 327,578 | -- | 230,958 | 100,208 | 50,225 | 1,070,111 |
| Eric M. Markell | 2008 | $347,500 | $ -- | $ 387,297 | $ -- | $243,000 | $281,473 | $ 39,767 | $1,299,037 |
| Executive Vice President | 2007 | 288,154 | -- | 447,382 | -- | 175,230 | 175,460 | 31,968 | 1,118,194 |
| and Chief Financial Officer | 2006 | 266,264 | -- | 178,994 | -- | 127,534 | 160,913 | 32,906 | 766,611 |
| Kimberly J. Harris | 2008 | $347,499 | $ -- | $386,781 | $ -- | $243,000 | $183,238 | $ 22,372 | $1,182,890 |
| Executive Vice President | 2007 | 288,604 | -- | 315,034 | -- | 175,230 | 74,582 | 22,876 | 876,326 |
| and Chief Resource Officer | 2006 | 262,346 | -- | 142,777 | -- | 126,107 | 102,350 | 21,521 | 655,101 |
| Jennifer L. O'Connor | 2008 | $308,313 | $ -- | $372,560 | $ -- | $174,656 | $172,627 | $ 31,684 | $1,059,840 |
| Senior Vice President | 2007 | 297,754 | -- | 348,608 | -- | 143,370 | 125,354 | 29,002 | 944,088 |
| General Counsel, Corporate Secretary, and Chief Ethics and Compliance Officer | 2006 | 287,163 | -- | 166,226 | -- | 137,528 | 122,079 | 32,192 | 745,188 |

1 *Reflects accounting expense recognized during each year for all outstanding stock awards and option awards, in accordance with SFAS No. 123R. For stock awards, this includes amounts recognized for grants of performance-based LTIP awards made in and prior to the year. The actual payment of the LTIP grants depends on Company performance and requires a threshold performance before any payment is made. Assumptions used in the calculation of these amounts are included in footnote 16 to the Company's audited financial statements for the fiscal year ended December 31, 2008 included in the Company's Form 10-K (the "2008 Form 10-K"). A description of the LTIP grants and the estimated threshold, target and maximum amounts that could be paid for the 2008 LTIP grants are set forth in the "2008 Grants of Plan-Based Awards" table. For option awards, this represents for Mr. Reynolds in 2006 a $99,793 accounting expense related to his stock options that were fully vested in 2006.*

2 *Reflects annual cash incentive compensation paid under the 2008 Goals and Incentive Plan. These amounts are based on performance in 2008, but were determined by the Committee in February 2009 and paid shortly thereafter or deferred at the executive's election. The 2008 Goals and Incentive Plan is described in further detail under "Compensation Discussion and Analysis". The threshold, target and maximum amounts of annual cash incentive compensation that could have been paid for 2008 performance are set forth in the "2008 Grants of Plan-Based Awards" table.*

3 *Reflects the aggregate increase in the actuarial present value of the executive's accumulated benefit under all pension plans during the year. The amounts are determined using interest rate and mortality rate assumptions consistent with those used in the Company's financial statements and includes amounts which the executive may not currently be entitled to receive because such amounts are not vested. Information regarding these pension plans is set forth in further detail under "2008 Pension Benefits." Mr. Reynolds does not participate in the SERP, and his accumulated benefit shown is only from the qualified pension plan. Also included in this column are the portion of Deferred Compensation Plan earnings that are considered above market. These amounts for 2008 are: Mr. Reynolds, $2,739; Ms. O'Connor, $2,770; and Mr. Markell, $1,373. These amounts for 2007 are: Mr. Reynolds, $420; Ms. O'Connor, $544; and Mr. Markell, $252. These amounts for 2006 are: Mr. Reynolds, $423; Ms. O'Connor, $567; and Mr. Markell, $244. See the "2008 Nonqualified Deferred Compensation" table for all Deferred Compensation Plan earnings.*

4 *All Other Compensation is shown in detail in the table below.*

### Detail of All Other Compensation

| Name | Perquisites and Other Personal Benefits ($)[1] | Tax Reimbursements ($) | Discounted Securities Purchases ($) | Payments/ Accruals on Termination Plans ($) | Registrant Contributions to Defined Contribution Plans ($)[2] | Insurance Premiums ($) | Other ($)[3] |
|---|---|---|---|---|---|---|---|
| Stephen P. Reynolds | $9,479 | $ -- | $ -- | $ -- | $302,289 | $ -- | $4,356 |
| Bertrand A. Valdman | 5,927 | -- | -- | -- | 40,037 | -- | 1,696 |
| Eric M. Markell | 4,605 | -- | -- | -- | 33,614 | -- | 1,548 |
| Kimberly J. Harris | 5,528 | -- | -- | -- | 15,764 | -- | 1,080 |
| Jennifer L. O'Connor | 2,500 | -- | -- | -- | 28,470 | -- | 714 |

1 *Annual reimbursement for financial planning, tax planning, and/or legal planning, up to a maximum of $5,000 for Mr. Reynolds and Mr. Valdman and $2,500 for other Named Executive Officers. Club use is primarily for business purposes, but Company club expense is included where the executive is also able to use the club for personal use. Expenses for personal club use are directly paid by the executive, not PSE.*

2 *Includes Company contributions during 2008 to PSE's Investment Plan (a tax qualified 401(k) plan) and the Deferred Compensation Plan. For Mr. Reynolds, this includes the Company contribution to the Performance-Based Retirement Equivalent Stock Account, which is described in more detail in the "2008 Nonqualified Deferred Compensation" section.*

3 *Other column includes the value of imputed income for life insurance.*

### 2008 Grants of Plan-Based Awards

The following table presents information regarding 2008 grants of annual incentive awards and LTIP awards, including the 2008 range of potential payouts for the annual incentive awards and performance share awards. In connection with the completion of the merger on February 6, 2009, all outstanding equity incentive plan awards were cancelled in exchange for the cash payments described under "Payments Upon Completion of the Merger."

| | | Estimated Future Payouts under Non-Equity Incentive Plan Awards | | | Estimated Future Payouts under Equity Incentive Plan Awards | | | |
|---|---|---|---|---|---|---|---|---|
| Name | Grant Date | Threshold ($) | Target ($) | Maximum ($) | Threshold (#) | Target (#) | Maximum (#) | Grant Date Fair Value of Stock and Option Awards ($)[4] |
| Stephen P. Reynolds | | | | | | | | |
| Annual Incentive [1] | 1/1/2008 | $350,625 | $701,250 | $1,542,750 | | | | |
| LTIP PS [2] | 2/29/2008 | | | | 10,549 | 35,163 | 61,535 | $938,852 |
| LTIP RS [3] | 2/29/2008 | | | | | 15,070 | 15,070 | 402,369 |
| Bertrand A. Valdman | | | | | | | | |
| Annual Incentive [1] | 1/1/2008 | $ 118,500 | $237,000 | $ 521,400 | | | | |
| LTIP PS [2] | 2/28/2008 | | | | 2,334 | 7,781 | 13,617 | $ 208,142 |
| LTIP RS [3] | 2/28/2008 | | | | | 7,781 | 7,781 | 208,142 |
| Eric M. Markell | | | | | | | | |
| Annual Incentive [1] | 1/1/2008 | $ 108,000 | $216,000 | $ 475,200 | | | | |
| LTIP PS [2] | 2/28/2008 | | | | 2,128 | 7,092 | 12,411 | $ 189,711 |
| LTIP RS [3] | 2/28/2008 | | | | | 7,092 | 7,092 | 189,711 |
| Kimberly J. Harris | | | | | | | | |
| Annual Incentive [1] | 1/1/2008 | $ 108,000 | $216,000 | $ 475,200 | | | | |
| LTIP PS [2] | 2/28/2008 | | | | 2,128 | 7,092 | 12,411 | $ 189,711 |
| LTIP RS [3] | 2/28/2008 | | | | | 7,092 | 7,092 | 189,711 |
| Jennifer L. O'Connor | | | | | | | | |
| Annual Incentive [1] | 1/1/2008 | $ 77,625 | $155,250 | $ 341,550 | | | | |
| LTIP PS [2] | 2/28/2008 | | | | 1,585 | 5,283 | 9,245 | $ 141,320 |
| LTIP RS [3] | 2/28/2008 | | | | | 5,283 | 5,283 | $141,320 |

1 *Annual Goals and Incentive Plan. As described in the "Compensation Discussion and Analysis," the plan has dual funding triggers in 2008 of $1.15 EPS and SQI performance of 5/11. Payment would be $0 if either trigger is not met. The threshold estimate assumes $1.15 EPS and SQI performance at 10/11. The target estimate assumes $1.20 EPS and SQI performance at 10/11. The maximum estimate assumes $1.55 EPS or higher and SQI performance at 11/11.*

2 *LTIP Performance Shares for 2008-2010 cycle. As described in the "Compensation Discussion and Analysis," Performance Shares are calculated at the end of the three-year performance cycle based on Company results for relative TSR and SQI performance. Threshold estimate assumes that Puget Energy's relative TSR is below the 25th percentile of the comparison group and the SQI result is 10/11, for an overall payment of 30% of target. Target estimate assumes that Puget Energy's relative TSR equals the 50th percentile of the comparison group and the SQI result is 10/11, for an overall payment of 100% of target. Maximum estimate assumes that Puget Energy's TSR is at or above the 85th percentile of the comparison group and the SQI result is 10/11, for an overall payment of 175% of target. Payments of Performance Shares vary significantly and have paid at the following percentages of target: 2004-2006, 17.5%, 2005-2007, 89.5%, and 2006-2008, 149.5%.*

3 *LTIP Performance-Based Restricted Stock for 2008-2010 cycle. The Performance-Based Restricted Stock vests based on achievement of 8/11 SQIs and continued service during the performance cycle. Target and Maximum estimates both assume that all shares vest.*

4 *Grant Date Fair Value is calculated as the target number of shares at the closing price of Puget Energy stock on February 29, 2008 of $26.70 for Mr. Reynolds and February 28, 2007 of $26.75 for the other Named Executive Officers.*

## Outstanding Equity Awards at 2008 Fiscal Year-End

The following table provides information regarding outstanding stock options and unvested stock awards held as of December 31, 2008. In connection with the completion of the merger on February 6, 2009, all outstanding equity awards were cancelled in exchange for the cash payments described under "Payments Upon Completion of the Merger."

| | Option Awards | | | | Stock Awards | | | |
|---|---|---|---|---|---|---|---|---|
| Name | Number of Securities Underlying Unexercised Options Exercisable (#) | Number of Securities Underlying Unexercised Options Unexercisable (#) | Option Exercise Price ($) | Option Expiration Date | Number of Shares or Units of Stock Held that Have Not Vested (#)[1] | Market Value of Shares or Units of Stock Held that Have Not Vested ($)[1] | Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)[2] | Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)[2] |
| Stephen P. Reynolds | | | | | | | | |
| Stock Option Granted 1//2002 | 300,000 | -- | $22.51 | 1/8/2012 | | | | |
| LTIP Cycle 2007-2009 | | | | | 26,533 | $723,546 | 53,909 | $1,470,108 |
| LTIP Cycle 2008-2010 | | | | | 7,877 | 214,792 | 59,611 | $1,625,604 |
| Bertrand A. Valdman | | | | | | | | |
| LTIP Cycle 2007-2009 | | | | | 5,748 | $156,754 | 14,544 | $ 396,605 |
| LTIP Cycle 2008-2010 | | | | | 1,743 | 47,530 | 16,970 | 462,82 |
| Eric M. Markell | | | | | | | | |
| LTIP Cycle 2007-2009 | | | | | 3,640 | $ 99,275 | 9,211 | $251,182 |
| LTIP Cycle 2008-2010 | | | | | 1,394 | 38,013 | 15,662 | 427,111 |
| Kimberly J. Harris | | | | | | | | |
| LTIP Cycle 2007-2009 | | | | | 3,707 | $101,078 | 9,378 | $255,741 |
| LTIP Cycle 2008-2010 | | | | | 1,419 | 38,703 | 15,637 | 426,421 |
| Jennifer L. O'Connor | | | | | | | | |
| LTIP Cycle 2007-2009 | | | | | 3,972 | $108,305 | 10,049 | $274,023 |
| LTIP Cycle 2008-2010 | | | | | 1,183 | 32,271 | 10,462 | 285,288 |

1 *The amounts in these columns reflect "banked" Performance Shares. "Banked shares" are described in the "Long-Term Incentive Compensation" section of the "Compensation Discussion and Analysis." The 2007-2009 and 2008-2010 LTIP cycles were forecast to finish between target and maximum. Figures are shown at maximum.*

2 *The amounts in these columns reflect "unbanked" Performance Shares and unvested Performance-Based Restricted Stock. The 2007-2009 and 2008-2010 LTIP cycles were forecast to finish between target and maximum. Figures are shown at maximum.*

## Stock Vested in 2008

The following table provides information regarding vesting of stock awards during 2008. No stock options were exercised during 2008.

| | Stock Award | |
|---|---|---|
| Name | Number of Shares Acquired on Vesting (#) | Value Realized on Vesting ($) |
| Stephen P. Reynolds [1,2] | 164,555 | $4,487,415 |
| Bertrand A. Valdman [2,3] | 27,871 | 760,042 |
| Eric M. Markell [2] | 16,767 | 457,236 |
| Kimberly J. Harris [2] | 16,631 | 453,527 |
| Jennifer L. O'Connor[2] | 18,461 | 503,431 |

1 *Vesting of 12,000 shares of employment restricted stock grant on January 8, 2008 and 60,000 shares of performance based restricted stock on May 6, 2008.*

2 *Vesting of 2006-2008 LTIP cycle at 149.5% of target (Performance Shares and Performance-Based Restricted Stock); vesting of 2007-2009 LTIP cycle at 25% (Performance-Based Restricted Stock): and vesting of 2008-2010 LTIP cycle at 15% (Performance-Based Restricted Stock).*

3 *Vesting of part of employment restricted stock grant.*

**2008 Pension Benefits**

The Company and its affiliates maintain two pension plans: the Retirement Plan for Employees of Puget Sound Energy, Inc. (the "Retirement Plan") and the Puget Sound Energy, Inc. Supplemental Executive Retirement Plan (the "SERP"). The following table provides information for each of the Named Executive Officers regarding the actuarial present value of the officer's accumulated benefit and years of credited service under the Retirement Plan and the SERP. The present value of accumulated benefits was determined using interest rate and mortality rate assumptions consistent with those used in the Company's financial statements. Except as described below in footnote (1), relating to Mr. Reynolds, each of the Named Executive Officers participates in both plans.

| NAME | PLAN NAME | NUMBER OF YEARS CREDITED SERVICE (#) | PRESENT VALUE OF ACCUMULATED BENEFIT ($)[2,3] | PAYMENTS DURING LAST FISCAL YEAR |
|---|---|---|---|---|
| Stephen P. Reynolds [1] | PSE Retirement Plan | 7.0 | $149,157 | $ -- |
| | PSE SERP | n/a | n/a | n/a |
| Bertrand A. Valdman | PSE Retirement Plan | 5.1 | 80,170 | -- |
| | PSE SERP | 5.1 | 391,452 | -- |
| Eric M. Markell | PSE Retirement Plan | 6.4 | 127,267 | -- |
| | PSE SERP | 6.4 | 740,362 | -- |
| Kimberly J. Harris | PSE Retirement Plan | 9.7 | 141,911 | -- |
| | PSE SERP | 9.7 | 455,150 | -- |
| Jennifer L. O'Connor | PSE Retirement Plan | 5.9 | 94,437 | -- |
| | PSE SERP | 5.9 | 471,737 | -- |

1 *Mr. Reynolds participates in the Retirement Plan, but does not participate in the SERP. In lieu of participating in the SERP, Mr. Reynolds receives an annual credit of performance-based stock equivalents to a Performance-Based Retirement Equivalent Stock Account in the Deferred Compensation Plan. Following the delisting of Puget Energy stock, the credit will be made in dollars. The value of this account at December 31, 2008 of $1,296,080 is also shown in the "2008 Nonqualified Deferred Compensation Plan" table and the stock equivalent program is further described in the narrative text accompanying that table.*

2 *The amounts reported in this column for each officer were calculated assuming no future service or pay increases. Present values were calculated assuming no pre-retirement mortality or termination. The values under the Retirement Plan and the SERP are the actuarial present values as of December 31, 2008 of the benefits earned as of that date and payable at normal retirement age (age 65 for the Retirement Plan and age 62 for the SERP). Future cash balance interest credits are 4.0% for 2009 and are assumed to average 6.5% annually thereafter. The discount assumption is 6.2%, and the post-retirement mortality assumption is based on the 2009 417(e) unisex mortality table. An applicable interest rate of 6% is assumed for the purpose of converting annuity benefits to lump sum amounts at retirement. These assumptions are consistent with the ones used for the Retirement Plan and the SERP for financial reporting purposes for 2008. In order to determine the change in pension values for the "Summary Compensation" table, the values of the Retirement Plan and the SERP benefits were also calculated as of December 31, 2007 for the benefits earned as of that date using the assumptions used for financial reporting purposes for 2007. These assumptions included assumed average cash balance interest credits of 6.5% for all future years, a discount assumption of 6.3% and post-retirement mortality assumption based on the 2008 417(e) unisex mortality table. Other assumptions used to determine the value as of December 31, 2007 were the same as those used for December 31, 2008.*

3 *As described in footnote (2) above, the amounts reported for the SERP in this column are actuarial present values, calculated using the actuarial assumption used for financial reporting purposes. These assumptions are different from those used to calculate the actual amount of benefit payments under the SERP (see text below for a discussion of the actuarial assumptions used to calculate actual payment amounts). The following table shows the estimated lump sum amount that would be paid under the SERP to each SERP-eligible Named Executive Officer at age 62 (without discounting to the present), calculated as if such Named Executive Officer had terminated employment on December 31, 2008. Each SERP-eligible Named Executive Officer was vested in his or her SERP benefits as of December 31, 2008.*

| NAME | LUMP SUM |
|---|---|
| Bertrand A. Valdman | $1,030,027 |
| Eric M. Markell | 970,520 |
| Kimberly J. Harris | 1,291,158 |
| Jennifer L. O'Connor | 852,298 |

**Retirement Plan**

Under the Retirement Plan, Puget Energy's and PSE's eligible salaried employees, including the Named Executive Officers, accrue benefits in accordance with a cash balance formula, beginning on the later of their date of hire or March 1, 1997. Under this formula, for each calendar year after 1996, age-weighted pay credits are allocated to a bookkeeping account (a "Cash Balance Account") for each participant. The pay credits range from 3% to 8% of eligible compensation. Eligible compensation generally includes base salary and bonuses (other than bonuses paid under the LTIP, signing, retention and similar bonuses), up to the limit imposed by the Internal Revenue Code. For 2008, the Internal Revenue Code compensation limit was $230,000. For 2009, it is $245,000. In addition, as of March 1, 1997, the Cash Balance Account of each participant who was participating in the Retirement Plan on March 1, 1997 was credited with an amount based on the actuarial present value of that participant's accrued benefit, as of February 28, 1997, under the Retirement Plan's previous formula.

Amounts in the Cash Balance Accounts are also credited with interest. The interest crediting rate is 4% per year or such higher amount as PSE may determine. For 2008 the annual interest crediting rate was 6.5%. For 2009 it is 4.0%.

A participant's Retirement Plan benefit generally vests upon the earlier of the participant's completion of three years of active service with Puget Energy, PSE or their affiliates or attainment of age 65 (the Retirement Plan's normal retirement age) while employed by the Company or one of its affiliates. Normal retirement benefit payments begin to a vested participant as of the first day of the month following the later of the participant's termination of employment or attainment of age 65. However, a vested participant may elect to have his or her benefit under the Retirement Plan paid, or commence to be paid, as of the first day of any month commencing after the date on which his or her employment with Puget Energy, PSE and their affiliates terminates. If benefit payments commence prior to the participant's attainment of age 65, then the amount of the monthly payments will be reduced for early commencement to reflect the fact that payments will be made over a longer period of time. This reduction is subsidized — that is, it is less than a pure actuarial reduction. The amount of this reduction is, on average, 0.30% for each of the first 60 months, 0.33% for each of the second 60 months, 0.23% for each of the third 60 months and 0.17% for each of the fourth 60 months that the payment commencement date precedes the participant's 65th birthday. Further reductions apply for each additional month that the payment commencement date precedes the participant's 65th birthday. As of December 31, 2008, all the Named Executive Officers were vested in their benefits under the Retirement Plan and, hence, would be eligible to commence benefit payments upon termination.

The normal form of benefit payment for unmarried participants is a straight life annuity providing monthly payments for the remainder of the participant's life, with no death benefits. The straight life annuity payable on or after the participant's normal retirement age is actuarially equivalent to the balance in the participant's Cash Balance Account as of the date of distribution. For married participants, the normal form of benefit payment is an actuarially equivalent joint and 50% survivor annuity with a "pop-up" feature providing reduced monthly payments (as compared to the straight life annuity) for the remainder of the participant's life and, upon the participant's death, monthly payments to the participant's surviving spouse for the remainder of the spouse's life in an amount equal to 50% of the amount being paid to the participant. Under the pop-up feature, if the participant's spouse predeceases the participant, the participant's monthly payments increase to the level that would have been provided under the straight life annuity. In addition, the Retirement Plan provides several other annuity payment options and a lump sum payment option that can be elected by participants. All payment options are actuarially equivalent to the straight life annuity. However, in no event will the amount of the lump sum payment be less than the balance in the participant's Cash Balance Account as of the date of distribution (in some instances the amount of the lump sum distribution may be greater than the balance in the Cash Balance Account due to differences in the morality table and interest rates used to calculate actuarial equivalency).

If a participant in the cash balance portion of the Retirement Plan dies while employed by the Company or any of its affiliates, then his or her Retirement Plan benefit will be immediately vested. If a vested participant dies before his or her Retirement Plan benefit is paid, or commences to be paid, then the participant's Retirement Plan benefit will be paid to his or her beneficiary(ies). If a participant dies after his or her Retirement Plan benefit has commenced to be paid, then any death benefit will be governed by the form of payment elected by the participant.

**Supplemental Executive Retirement Plan**

The SERP provides a benefit to participating Named Executive Officers that supplements the retirement income provided to the executives by the Retirement Plan. As discussed in the Compensation Discussion and Analysis on page 146, Mr. Valdman, Mr. Markell, Ms. Harris and, Ms. O'Connor participate in the SERP.

A participating Named Executive Officer's SERP benefit generally vests upon the executive's completion of five years of participation in the SERP while employed by the Company or any of its affiliates. Mr. Markell, Ms. Harris and Ms. O'Connor are vested in their SERP benefits based on their years of service. By agreement with PSE, Mr. Valdman became vested in his SERP benefit on the date he was hired. The monthly benefit payable under the SERP to a vested executive (calculated in the form of a straight life annuity payable for the executive's lifetime commencing at the later of the executive's date of termination or attainment of age 62) is equal to (1) below minus the sum of (2) and (3) below:

(1) One-twelfth (1/12) of the executive's highest average earnings times the executive's years of credited service (not in excess of 15) times 3--1/3%. For purposes of the SERP, "highest average earnings" means the average of the executive's highest three calendar years of earnings. The three calendar years do not have to be consecutive, but they must be among the last ten calendar years completed by the executive prior to his or her termination. "Earnings" for this purpose include base salary and annual bonus, but do not include long-term incentive compensation. An executive will receive one "year of credited service" for each consecutive 12-month period he or she is employed by the Company or its affiliates. If an executive becomes entitled to disability benefits under PSE's long-term disability plan, then the executive's highest average earnings will be determined as of the date the executive became disabled, but the executive will continue to accrue years of credited service until he or she begins to receive SERP benefits.

(2) The monthly amount payable (or that would be payable) under the Retirement Plan to the executive in the form of a straight life annuity commencing as of the first day of the month following the later of the executive's date of termination or attainment of age 62, and includes amounts previously paid or segregated pursuant to a qualified domestic relations order.

(3) The actuarially equivalent monthly amount payable (or that would be payable) to the executive as of the first day of the month following the later of the executive's date of termination or attainment of age 62 from any pension-type rollover accounts (including the Annual Cash Balance Restoration Account) within the Deferred Compensation Plan. These accounts are described in more detail in the "2008 Nonqualified Deferred Compensation" section.

Normal retirement benefits under the SERP generally are paid or commence to be paid within 90 days following the later of the Named Executive Officer's termination of employment or attainment of age 62. Except as provided below, SERP benefits are normally paid in a lump sum that is equal to the actuarial present value of the monthly straight life annuity benefit. An executive may have elected on or before December 31, 2008 to have this lump sum transferred to the Deferred Compensation Plan, rather than paid directly to the executive, after which it will be paid in accordance with the provisions of the Deferred Compensation Plan. In lieu of the normal form of payment, an executive may elect to receive his or her SERP benefit in the form of monthly installment payments over a period of two to 20 years, in a straight life annuity or in a joint and survivor annuity with a 100%, 75%, 50% or 25% survivor benefit. All payment options are actuarially equivalent to the straight life annuity. Mr. Markell is the only Named Executive Officer eligible for early retirement benefit payments under the SERP. Payments to the executives following termination of employment of SERP benefits are generally delayed for six months in accordance with the requirements of Section 409A of the Internal Revenue Code.

If a participating Named Executive Officer dies while employed by Puget Energy, PSE or any of their affiliates or after becoming vested in his or her SERP benefit, but before his or her SERP benefit has commenced to be paid, then the executive's surviving spouse will receive a lump sum benefit equal to the actuarial equivalent of the survivor benefit such spouse would have received under the joint and 50% survivor annuity option. This amount will be calculated assuming the executive would have commenced benefit payments in that form on the first day of the month following the later of his or her death or attainment of age 62. The lump sum benefit will then be reduced by one-third of one percent (1/3%) for each month by which the executive's date of death preceded what would have been his or her 62nd birthday. Distribution will be made to the executive's surviving spouse as soon as administratively practicable after the executive's death. If the executive is not married, then no death benefit will be paid. If an executive dies after his or her SERP benefit has commenced to be paid, then any death benefit will be governed by the form of payment elected by the executive.

**2008 Nonqualified Deferred Compensation**

The following table provides information for each of the Named Executive Officers regarding aggregate executive and Company contributions and aggregate earnings for 2008 and year-end account balances under the Deferred Compensation Plan.

| NAME | EXECUTIVE CONTRIBUTIONS IN 2008 ($)[1] | REGISTRANT CONTRIBUTIONS IN 2008 ($)[2] | AGGREGATE EARNINGS IN 2008 ($)[3] | AGGREGATE WITHDRAWALS/ DISTRIBUTIONS ($)[4] | AGGREGATE BALANCE AT DECEMBER 31, 2008 ($)[5] |
|---|---|---|---|---|---|
| Stephen P. Reynolds | $107,856 | $287,206 | $ 3,586 | $105,485 | $2,597,652 |
| Bertrand A. Valdman | 34,883 | 23,987 | 20,949 | -- | 197,976 |
| Eric M. Markell | 26,318 | 17,850 | 5,378 | -- | 237,340 |
| Kimberly J. Harris | -- | -- | 4,079 | -- | 191,590 |
| Jennifer L. O'Connor | 11,601 | 12,420 | 16,490 | -- | 290,077 |

1 *The amount in this column for each executive reflects elective deferrals by the officer of salary, annual incentive compensation or vested performance shares paid or earned in 2008. Deferred salary amounts are: Mr. Reynolds, $54,917; Mr. Valdman, $26,267; Mr. Markell, $23,800; Ms. Harris, $0; and Ms. O'Connor, $11,601. Deferred incentive compensation amounts are: Mr. Reynolds, $52,939; Mr. Valdman, $8,616; Mr. Markell, $2,518; Ms. Harris, $0; and Ms. O'Connor, $0.*

2 *The amount reported in this column for each executive reflects contributions by PSE consisting of the Annual Investment Plan Restoration Amount and Annual Cash Balance Restoration Amount. For Mr. Reynolds, the amount also includes $207,522 in value of performance-based stock equivalents credited in the Deferred Compensation Plan's Performance-Based Retirement Equivalent Stock Account and calculated pursuant to his employment agreement based on the average of the high and low price of Puget Energy stock on January 8, 2008 of $27.40. These amounts are also included in the total amounts shown in the All Other Compensation column of the "Summary Compensation" table.*

3 *The amount in this column for each officer reflects dividends on deferred stock units and the change in value of other investment tracking funds.*

4 *The amount in this column for Mr. Reynolds reflects a scheduled interim payment pursuant to the terms of the Deferred Compensation Plan.*

5 *Of the amounts in this column, the following amounts have also been reported in the Summary Compensation Table for this year and 2007 and 2006.*

| NAME | REPORTED FOR 2008 ($) | REPORTED FOR 2007 ($) | REPORTED FOR 2006 ($) | TOTAL ($) |
|---|---|---|---|---|
| Stephen P. Reynolds | $ 395,062 | $ 403,540 | $ 359,600 | $ 1,158,202 |
| Bertrand A. Valdman | 58,870 | 54,733 | 62,767 | 176,370 |
| Eric M. Markell | 44,168 | 31,005 | 32,933 | 108,106 |
| Kimberly J. Harris | -- | -- | 26,111 | 26,111 |
| Jennifer L. O'Connor | 24,021 | 21,234 | 38,115 | 83,370 |

**Deferred Compensation Plan**

The Named Executive Officers are eligible to participate in the Deferred Compensation Plan and may defer up to 100% of base salary, annual incentive compensation and vested performance shares. In addition, each year, executives are eligible to receive Company contributions to restore benefits not available to them under the Company's tax-qualified plans due to limitations imposed by the Internal Revenue Code. The Annual Investment Plan Restoration Amount equals the additional matching and any other employer contribution under the 401(k) plan that would have been credited to an electing executive's 401(k) plan account if the Internal Revenue Code limitations were not in place and if deferrals under the Deferred Compensation Plan were instead made to the 401(k) plan. The Annual Cash Balance Restoration Amount equals the actuarial equivalent of any reductions in an executive's accrued benefit under the Retirement Plan due to Internal Revenue Code limitations or as a result of deferrals under the Deferred Compensation Plan. An executive must generally be employed on the last day of the year to receive these Company contributions, unless he or she retires or dies during the year in which case the Company will contribute a prorated amount.

In lieu of participation in the SERP, Mr. Reynolds receives an annual credit of performance-based stock equivalents to his Deferred Compensation Plan's Performance-Based Retirement Equivalent Stock Account each January commencing on January 1, 2003. The number of stock equivalents is determined by calculating the number of shares obtained by taking 15% of Mr. Reynolds' base salary and annual bonus for the preceding year and dividing that amount by the average per-share closing price of Puget Energy stock on the last day of October, November and December of the preceding year. The stock equivalents are entitled to dividend equivalents equal to all dividends declared on Puget Energy stock, which are then credited to the Performance-Based Retirement Equivalent Stock Account as additional stock equivalents. The stock equivalents vest over seven years from January 1, 2002 at 15% per year for the first six years, with the balance vesting on May 6, 2008.

The Named Executive Officers choose how to credit deferred amounts among four investment tracking funds. The tracking funds mirror performance in major asset classes of bonds, stocks, Puget Energy stock, and interest crediting. The tracking funds differ from the investment funds offered in the 401(k) plan. The 2008 calendar year returns of these tracking funds were:

| | |
|---|---|
| Vanguard Total Bond Market Index | 5.19% |
| Vanguard 500 Index | (37.02)% |
| Puget Energy Stock | 2.18% |
| Interest Crediting Fund | 6.47% |

The Named Executive Officers may change how deferrals are allocated to the tracking funds at any time, subject to insider trading rules and other Deferred Compensation Plan restrictions that limit the transfer of funds into or out of Puget Energy stock. Changes generally become effective as of the first trading day of the following calendar quarter. As of the delisting of Puget Energy stock following the Company's change in control on February 6, 2009, the Puget Energy tracking fund was no longer available and the deferred amounts credited therein were reallocated in accordance with the executive's direction or, if none, into the interest crediting tracking fund.

The Named Executive Officers generally may choose how and when to receive payments under the Deferred Compensation Plan. There are three types of in-service withdrawals. First, an executive may choose an interim payment of deferred based salary, annual bonus or vested performance shares by designating a plan year for payment at the time of his or her deferral election. The interim payment is made in a lump sum within 60 days after the last day of the designated plan year, which must be at least two years following the plan year of the deferral. Second, an in-service withdrawal may also be made to an executive upon a qualifying hardship event and demonstrated need. Third, only with respect to amounts deferred and vested prior to 2005, the executive may elect an in-service withdrawal for any reason by paying a 10% penalty. Payments upon termination of employment depend on whether the executive is then eligible for retirement. If the executive's termination occurs prior to his or her retirement date (generally the earlier of attaining age 62 or age 55 with five years of credited service), the executive will receive a lump sum payment of his or her vested account balance. If the executive’s termination occurs after his or her retirement date, the executive may choose to receive payments in a lump sum or via one of several installment options (fixed amount, specified amount, annual or monthly installments, of up to 20 years), although an executive receiving payments from the Puget Energy stock tracking fund may elect only a lump sum payment or installments payable in a specified amount or annually. Mr. Reynolds and Mr. Markell are the only Named Executive Officers currently retirement eligible. Payments to the executive following a termination or retirement date are generally delayed for six months in accordance with the requirements of Section 409A of the Internal Revenue Code.

**Potential Payments Upon Termination or Change in Control**

The “Estimated Potential Incremental Payments Upon Termination or Change in Control” table reflects the estimated amount of incremental compensation payable to each of the Named Executive Officers in the event of (i) an involuntary termination without cause or for good reason that is not in connection with a change in control; (ii) a change in control; (iii) an involuntary termination without cause or for good reason in connection with a change in control; (iv) retirement; (v) disability; or (vi) death.

The amounts shown assume that the change in control or termination of employment was effective as of December 31, 2008 and that the price of Puget Energy stock upon which certain of the calculations are made was the closing price of $27.27 on December 31, 2008. These amounts are estimates of the incremental amounts that would be paid out to the executive upon a change in control or such terminations.

The actual amounts to be paid out can only be determined at the time of a change in control or an executive’s termination. The Company's merger, which was completed on February 6, 2009, was a change in control event under the Company's existing change in control agreements and arrangements that resulted in the payment of the amounts shown in “Payments Upon Completion of the Merger.”

**Payments Made Upon Termination**

Regardless of the manner in which an executive's employment terminates, the executive is entitled to receive amounts earned during the term of employment. These amounts, which are not included in the "Estimated Potential Incremental Payments Upon Termination or Change in Control" table, include:

- Amounts contributed by the executive under the PSE Investment Plan and Deferred Compensation Plan; and
- Amounts accrued and vested through the PSE Retirement Plan and SERP.

**Payments Made Upon Retirement**

In the event of the retirement of a Named Executive Officer, in addition to the items identified above, the executive will receive the estimated incremental benefits reflected in the table below as a result of the following:

- Pro-rata payment of Performance Awards, which will be paid based on the value at the end of the year pro-rated through the month of retirement based on Puget Energy's relative Total Shareholder Return as of the quarter-end of the quarter prior to retirement; and
- Named Executive Officers also receive a pro-rata payment of annual incentive awards, which is paid pro-rata to the extent earned in the year following retirement, provided the executive worked a minimum of 520 hours during the year. No estimated amounts are shown in the table below for annual incentive compensation earned in 2008.

**Payments Made Upon Disability or Death**

In the event of the disability or death of a Named Executive Officer, in addition to the benefits listed above, the executive will receive benefits under the PSE disability plan or life insurance plan available generally to all salaried employees. These disability and life insurance amounts are not reflected in the table below. The executive will also receive supplemental disability and life insurance. The disability coverage is extended to include base salary and target incentive pay. Life insurance benefit is provided at two times base salary and target annual incentive bonus if the executive dies while employed by PSE with a reduction for amounts payable under the applicable group policy, or a single sum amount equal to the actuarial equivalent of the combined annual annuity benefit if the executive dies after retiring.

**Payments Made Pursuant to Employment and Change in Control Agreements**

Puget Energy and Puget Sound Energy (together, the "Company") entered into an employment agreement with Mr. Reynolds as of January 1, 2002 to secure his services as Chief Executive Officer and President. The agreement has an initial term of three years after which time it will be automatically renewed for one-year terms unless notice of termination is given by either party at least 180 days prior to the expiration of the then current term. Pursuant to the agreement, Mr. Reynolds was appointed to the Board of Directors and the Board will recommend him for reelection during the term of the agreement. The agreement was amended on May 10, 2005, February 9, 2006 and February 28, 2008. The agreement provides for the following benefits, the estimated value of which is included in the "Estimated Potential Incremental Payments Upon Termination or Change in Control" table.

If at any time the Company terminates Mr. Reynolds' employment without cause, or Mr. Reynolds terminates his employment with good reason, Mr. Reynolds will then receive the following severance benefits:

- An amount equal to two times his then current annual base salary and target annual incentive bonus;
- Accelerated two years of vesting in his Performance-Based Retirement Equivalent Stock Account in the Deferred Compensation Plan; and
- Accelerated vesting of stock options granted under the agreement.

If a change in control occurs during the term of the employment agreement, Mr. Reynolds will receive the following compensation and benefits at the time of the change in control:

- An amount equal to three times his then current base salary and target annual incentive bonus;
- Accelerated vesting of all outstanding equity awards;

- Accelerated vesting of his Performance-Based Retirement Equivalent Stock Account in the Deferred Compensation Plan;
- Continued medical, dental and insurance benefits for a period of three years or until he obtains similar coverage through another employer; and
- A cash payment equal to any excise taxes imposed by Section 4999 of the Internal Revenue Code due to payments received under the employment agreement or any other payment or benefit from the Company, plus the income taxes payable by him resulting from this cash payment.

The employment agreement contains a noncompetition covenant. Mr. Reynolds commits that for a period of two years following his voluntary termination, without good reason, he will not perform services for any person or entity selling or distributing electric power or natural gas in Washington, Oregon or Idaho, unless the Company consents in writing. The Company may enforce this covenant through injunctive relief or other appropriate remedies.

The employment agreement also contains an indemnification clause in favor of Mr. Reynolds. The Company commits to defend, indemnify and hold harmless Mr. Reynolds from all liabilities in connection with his service. As part of that commitment, the Company will continue to cover him under the Company's directors' and officers' liability insurance for six years following his termination of employment.

Under the employment agreement, "change in control," "good reason," and "cause" have the following meanings:

*Change in Control* means any one of the following events: (i) any person becomes the beneficial owner of more than 30% of Puget Energy's common stock or voting securities, with certain exceptions; (ii) the incumbent directors (including those nominees subsequently nominated or appointed by incumbent directors) cease for any reason to constitute at least a majority of the Board of Directors; and (iii) consummation of a reorganization, merger, consolidation or other business combination involving Puget Energy, or a sale of substantially all of the assets of either of the Puget Energy or PSE, unless (x) after such transaction the beneficial shareholders of the outstanding Puget Energy common stock and voting securities entitled to vote on director elections immediately prior to the transaction retain more than 60% of such common stock and voting securities; (y) no beneficial shareholder owns 30% or more of the then outstanding common stock or voting securities entitled to vote on director elections, and (z) at least a majority of the directors resulting from such transaction were incumbent directors at the time of executing the initial agreement providing for such transaction.

*Good Reason* includes the following actions by the Company: (i) assigning duties inconsistent with, or taking actions in diminution of, his position (including status, offices, titles and reporting requirements), authority, duties or responsibility under the employment agreement; (ii) failing to comply with the provisions of the employment agreement; (iii) requiring that he be based at any location other than its corporate headquarters or relocating the corporate headquarters more than 25 miles from Bellevue, Washington; and (iv) failing to assign the employment agreement to a successor or the successor failing to assume and be bound by it explicitly. Good Reason is triggered on a reasonable determination by Mr. Reynolds that any of the above events has occurred.

*Cause* means (i) the willful and continued failure to substantially perform Mr. Reynolds' duties or (ii) the willful engaging in gross misconduct materially and demonstrably injurious to the Company. Cause does not include any act or omission believed to be in good faith and in the best interests of the Company.

In February 2006 PSE entered into amended change in control agreements with each of Mr. Valdman, Mr. Markell, Ms. Harris and Ms. O'Connor (the "Executives"), the terms of which are the same for all four Executives. If a change in control occurs, for a period of two years following the change in control of PSE (the "employment period"), the Executives will receive continued base salary, annual incentive bonus and other incentive, savings and retirement plans and programs applicable to PSE peer executives at comparable levels to those prior to the change in control. These benefits are not reflected in the "Estimated Potential Incremental Payments Upon Termination or Change in Control" table.

At the time of the change in control, the Executives will receive the following benefits, the estimated value of which is included in the "Estimated Potential Incremental Payments Upon Termination or Change in Control" table.

- Accelerated vesting in the SERP.
- Accelerated vesting of any outstanding equity awards.
- A cash payment in consideration of all outstanding performance awards equal to the product of a deemed stock price (calculated based on the greater of (i) the average last sales price of Puget Energy stock on the NYSE in each of the 20 days preceding the change in control, and (ii) the highest price per share actually paid in connection with the change in control) multiplied by a deemed number of shares related to the performance awards (calculated based on the greater of (x) the total shares payable at the target award level on full vesting of each such award, and (y) the shares payable on full vesting of each such award if PSE achieved for each award cycle the same percentile ranking against its designated universe of companies which the PSE had achieved for the applicable cycle but ending with the fiscal quarter immediately prior to the change in control).

After a change in control, if at any time during the employment period PSE terminates an Executive's employment without cause or due to disability or death, or the Executive terminates his or her employment with good reason, PSE will pay the Executive:

- A lump sum in cash equal to (i) any accrued but unpaid base salary, (ii) a pro rata portion of the Executive's annual incentive bonus for the year, (iii) any accrued paid time off pay, and (iv) a severance benefit equal to three times the sum of the annual base salary and the annual incentive bonus for which he or she was eligible for the year in which the date of termination occurs, unless an acceptable release is not executed by the Executive in which case the severance benefit will equal one times such sum.
- A separate lump-sum supplemental retirement benefit equal to the difference between (x) the actuarial equivalent of the amount he or she would have received under the Retirement Plan and the SERP had his or her employment continued until the end of the employment period, and (y) the actuarial equivalent of the amount he or she actually receives or is entitled to receive under the Retirement Plan and SERP.
- Continued welfare and fringe benefits described above for the Executive and the Executive's family at least equal to those that would have been provided if the Executive's employment had not terminated through the remainder of the employment period, except that if the Executive becomes re-employed with another employer and is eligible to receive medical or other welfare benefits under another employer-provided plan, the medical and other welfare benefits received under the amended agreement will be secondary to those provided by the other employer.

If any payments paid or payable under the amended change in control agreement or otherwise are characterized as "excess parachute payments" within the meaning of Section 280G the Internal Revenue Code, then PSE will make cash payment to or on behalf of the Executive equal to any excise taxes imposed by Section 4999 of the Internal Revenue Code due to payments received under the amended agreement or any other payment or benefit from the Company, plus the income taxes payable by him or her resulting from this cash payment.

The amended change in control agreements contain a confidentiality clause. The Executives must keep confidential all secret or confidential information, knowledge or data relating to the Company and its affiliates obtained during their employment. The Executives may not disclose any such information, knowledge or data after their respective terminations of employment unless PSE consents in writing or as required by law. PSE cannot withhold or defer the payment of any amounts otherwise due under the agreement based on an Executive's asserted violation of the confidentiality clause.

Under the amended change in control agreements, "change in control" has the same meaning as under Mr. Reynolds' employment agreement. "Good reason" and "cause" have the following meanings:

*Good reason* means (i) the assignment of any duties inconsistent with, or taking action in diminution of, the Executive's position (including status, offices, titles and reporting requirements), authority, duties or responsibilities; (ii) any failure by PSE to comply with the provisions of the agreement regarding compensation during the employment period; (iii) requiring the Executive to be based at any location other than the Seattle/Bellevue metropolitan area; (iv) any purported termination of the Executive's employment other than as expressly permitted by the amended agreement; and

(v) PSE's failure to assign the amended agreement to a successor to PSE or failure of a successor to PSE to explicitly assume and agree to be bound by the amended agreement.

*Cause* means (i) the willful and continued failure to substantially perform the Executive's duties or (ii) the willful engaging in gross misconduct materially and demonstrably injurious to PSE. Cause does not include any act or omission believed to be in good faith and in the best interests of PSE.

The table below presents estimated incremental compensation payable to each of the Named Executive Officers as described above. The incremental compensation is presented in the following benefit categories:

- Cash severance: multiple of salary and target annual incentive; does not reflect salary paid or annual incentive compensation earned in 2008
- Stock options: in-the-money value, as of December 31, 2008 of unvested stock options that would vest
- Service-based stock awards: market value, as of December 31, 2008 of unvested equity awards that would vest; includes Restricted Stock and Restricted Stock Units
- Performance-Based Stock Awards: market value, as of December 31, 2008 of unvested performance-based restricted stock awards that would vest
- Performance Shares: amount calculated in accordance with formula in the amended change in control agreements
- Performance-Based Retirement Equivalent Stock Account: market value, as of December 31, 2008 of unvested portion of account that would vest
- SERP: estimated actuarial value of the Executive's supplemental pension benefits under the amended change in control agreements
- Health and welfare benefits: estimated value of benefits continued following the termination
- Perquisites, consisting of estimated value of continuation of financial planning and, for Mr. Valdman, relocation allowance
- Estimated value of excise tax gross-up

## Estimated Potential Incremental Payments Upon Termination or Change in Control

| | Involuntary Termination w/o Cause or for Good Reason | Upon Change in Control | After Change in Control Involuntary Termination w/o Cause or for Good Reason | Retirement | Disability | Death |
|---|---|---|---|---|---|---|
| Stephen P. Reynolds | | | | | | |
| Cash Severance (salary and/or annual incentive) | $3,052,500 | $ 4,578,750 | $ 4,578,750 | $ -- | $ -- | $ -- |
| Stock Options (vesting accelerated) | -- | -- | -- | -- | -- | -- |
| Service-Based Stock Awards (vesting accelerated) | -- | -- | -- | -- | -- | -- |
| Performance-Based Stock Awards (vesting accelerated) | -- | 794,000 | 794.000 | -- | -- | -- |
| Performance Shares (vesting accelerated) | -- | 3,470,790 | 3,470,790 | 954,695 | 954,695 | 954,695 |
| Performance-Based Retirement Equivalent Stock Account (vesting accelerated) | -- | -- | -- | -- | -- | -- |
| Health and Welfare Benefits (continuation) | -- | -- | 36,312 | -- | -- | -- |
| Supplemental Life Insurance | -- | -- | -- | -- | -- | 2,452,500 |
| Perquisites | -- | -- | -- | -- | -- | -- |
| Excise Tax Gross-Up | -- | 2,816,582 | 2,833,258 | -- | -- | -- |
| Total Estimated Incremental Value | $3,052,500 | $11,660,122 | $11,713,111 | $ 954,695 | $ 954,695 | $3,407,195 |
| Bertrand A. Valdman | | | | | | |
| Cash Severance (salary and/or annual incentive) | $ n/a | $ -- | $ 1,896,014 | $ -- | $ -- | $ -- |
| Service-Based Stock Awards (vesting accelerated) | n/a | -- | -- | -- | -- | -- |
| Performance-Based Stock Awards (vesting accelerated) | n/a | 405,829 | 405,829 | -- | -- | -- |
| Performance Shares (vesting accelerated) | n/a | 758,826 | 758,826 | -- | 207,825 | 207,825 |
| SERP (additional years of credited service)[1] | -- | -- | 492,829 | -- | -- | -- |
| Health and Welfare Benefits (continuation) | n/a | -- | 34,379 | -- | -- | -- |
| Supplemental Life Insurance | n/a | -- | -- | -- | -- | 869,000 |
| Perquisites | n/a | -- | 5,000 | -- | -- | -- |
| Excise Tax Gross-Up | n/a | -- | 1,108,018 | -- | -- | -- |
| Total Estimated Incremental Value | $ n/a | $ 1,164,655 | $ 4,700,896 | $ -- | $ 207,825 | $1,076,825 |
| Eric M. Markell | | | | | | |
| Cash Severance (salary and/or annual incentive) | $ n/a | $ -- | $ 1,728,000 | $ -- | $ -- | $ -- |
| Performance-Based Stock Awards (vesting accelerated) | n/a | 316,042 | 316,042 | -- | -- | -- |
| Performance Shares (vesting accelerated) | n/a | 572,065 | 572,065 | 144,858 | 144,858 | 144,858 |
| SERP (additional years of credited service)[1] | -- | -- | 497,580 | -- | -- | -- |
| Health and Welfare Benefits (continuation) | n/a | -- | 30,518 | -- | -- | -- |
| Supplemental Life Insurance | n/a | -- | -- | -- | -- | 792,000 |
| Perquisites | n/a | -- | 5,000 | -- | -- | -- |
| Excise Tax Gross-Up | n/a | -- | 1,185,866 | -- | -- | -- |
| Total Estimated Incremental Value | $ n/a | $ 888,106 | $ 4,335,070 | $ 144,858 | $ 144,858 | $936,858 |
| Kimberly Harris | | | | | | |
| Cash Severance (salary and/or annual incentive) | $ n/a | $ -- | $ 1,728,000 | $ -- | $ -- | $ -- |
| Performance-Based Stock Awards (vesting accelerated) | n/a | 318,267 | 318,267 | -- | -- | -- |
| Performance Shares (vesting accelerated) | n/a | 576,989 | 576,989 | -- | 146,713 | 146,713 |
| SERP (additional years of credited service)[1] | -- | -- | 684,540 | -- | -- | -- |
| Health and Welfare Benefits (continuation) | n/a | -- | 17,025 | -- | -- | -- |
| Supplemental Life Insurance | n/a | -- | -- | -- | -- | 792,000 |
| Perquisites | n/a | -- | 5,000 | -- | -- | -- |
| Excise Tax Gross-Up | n/a | -- | 1,069,191 | -- | -- | -- |
| Total Estimated Incremental Value | $ n/a | $ 895,255 | $ 4,399,012 | $ -- | $ 146,713 | $938,713 |
| Jennifer L. O'Connor | | | | | | |
| Cash Severance (salary and/or annual incentive) | $ n/a | $ -- | $ 1,397,250 | $ -- | $ -- | $ -- |
| Performance-Based Stock Awards (vesting accelerated) | n/a | 277,859 | 277,859 | -- | -- | -- |
| Performance Shares (vesting accelerated) | n/a | 520,356 | 520,356 | -- | 143,031 | 143,031 |
| SERP (additional years of credited service)[1] | n/a | -- | 352,718 | -- | -- | -- |
| Health and Welfare Benefits (continuation) | n/a | -- | 34,258 | -- | -- | -- |
| Supplemental Life Insurance | n/a | -- | -- | -- | -- | 621,000 |
| Perquisites | n/a | -- | 5,000 | -- | -- | -- |
| Excise Tax Gross-Up | n/a | -- | 875,924 | -- | -- | -- |
| Total Estimated Incremental Value | $ n/a | $ 798,216 | $ 3,463,366 | $ -- | $ 143,031 | $ 764,031 |

1 *SERP values are shown as the estimated incremental value that the Named Executive Officer would receive at age 62 as a result of the termination event shown in the column, relative to the vested benefit as of December 31, 2008. These values are based on interest rate and mortality rate assumptions consistent with those used in the Company's financial statements.*

**Payments Upon Completion of the Merger**

The Company's merger, which was completed on February 6, 2009, was a change in control event under the Company's existing change in control agreements and arrangements. The Named Executive Officers received the following amounts upon completion of the Company's merger: cash severance: $4,578,750 to Mr. Reynolds, per his 2002 employment agreement; payment of cash in exchange for vested stock options: $2,247,000 to Mr. Reynolds, per the Company's long-term incentive plan; and acceleration and payout in cash of unvested Performance Shares, including dividend equivalents, and unvested Performance-Based Restricted Stock from the 2007-2009 and 2008-2010 LTIP cycles, per the Company's long-term incentive plan: Mr. Reynolds $4,516,599, Mr. Valdman $1,187,235, Mr. Markell $908,311, Ms. Harris $915,509, and Ms. O'Connor $813,573. No excise tax was due on any of the payments to the Named Executive Officers in connection with the merger.

**DIRECTOR COMPENSATION FOR FISCAL YEAR 2008**

The following table sets forth information regarding compensation for each of the Company's nonemployee directors for 2008. The directors named in the table are those who served during 2008. Effective with the completion of the Company's merger on February 6, 2009, a new Board was appointed, which will establish director compensation for 2009.

As described in further detail below, the Company's nonemployee director compensation program in 2008 consisted of quarterly retainer fees of $20,000, payable in the form of Puget Energy shares until a director owned a number of Puget Energy shares equal in value to two years of retainer fees. Additional quarterly retainer amounts associated with serving as lead director, chairing Board committees and serving on the Audit Committee, and meeting fees were paid in cash. Directors could defer their cash or stock fees into deferred stock units.

| NAME | FEES EARNED OR PAID IN CASH[1] | STOCK AWARDS[2] | NONQUALIFIED DEFERRED COMPENSATION EARNINGS[3] | TOTAL |
|---|---|---|---|---|
| William S. Ayer | $24,800 | $80,000 | $ -- | $104,800 |
| Phyllis J. Campbell | 60,864 | 53,336 | 3,115 | 117,315 |
| Craig W. Cole | 24,400 | 80,000 | 1,578 | 105,578 |
| Stephen E. Frank | 40,800 | 80,000 | -- | 120,800 |
| Tomio Moriguchi | 18,400 | 80,000 | 14 | 98,414 |
| Dr. Kenneth P. Mortimer | 51,468 | 53,332 | -- | 104,800 |
| Sally G. Narodick | 58,268 | 53,332 | -- | 111,600 |
| Herbert B. Simon | 21,600 | 80,000 | -- | 101,600 |
| George W. Watson | 24,800 | 80,000 | -- | 104,800 |

1 *The amounts in this column reflect director compensation earned and paid in cash including amounts deferred under our Deferred Compensation Plan for Nonemployee Directors. Mr. Watson received 952 deferred stock units from deferrals of cash compensation totaling $24,800 in 2008.*

2 *The amounts in this column reflect the dollar amount the Company recognized for financial statement reporting purposes for 2008 in accordance with SFAS No. 123R for stock awards granted in 2008. The SFAS No. 123R fair value for these awards is equal to the fair market value of the underlying Puget Energy stock on the date of grant.*

3 *Represents earnings accrued to deferred compensation considered to be above market.*

**Nonemployee Director Compensation Program.** The 2008 nonemployee director compensation program was based on the following principles: (i) the level of nonemployee director compensation should be based on Board and committee responsibilities and be competitive with comparable companies and (ii) a significant portion of nonemployee director compensation should align director interests with the long-term interests of shareholders.

The 2008 compensation program for nonemployee directors was as follows:

- A base cash quarterly retainer fee of $20,000 payable in Puget Energy stock until a director owned a number of Puget Energy shares equal in value to two years of retainer fees.
- $1,600 for attendance at each Board and committee meeting, and $800 for each telephonic meeting lasting 60 minutes or less, for the first two months of 2007 and $1,600 and $800, respectively, thereafter.

Nonemployee directors were paid the following additional cash quarterly retainer fees in 2008:

- Lead independent director, $3,750
- Chair of the Audit Committee, $2,500
- Chair of the Compensation and Leadership Development Committee, $2,000
- Chair of the Governance and Public Affairs Committees, $1,500
- Each member of the Audit Committee other than the chair, $1,000

To facilitate stock ownership, 100% of the quarterly retainer fee was paid in the form of Puget Energy shares until a director owned a number of Puget Energy shares equal in value to two years of retainer fees.

After meeting this ownership requirement, a portion of the base quarterly retainer for a fiscal quarter was payable in shares of Puget Energy stock. Under the terms of the Nonemployee Director Plan and Board policies as then in effect, the number of shares was determined by dividing two-thirds of the base quarterly retainer by the fair market value of Puget Energy stock for the last business day of a fiscal quarter. For this purpose, fair market value for a single trading day was the average of the high and low trading prices for Puget Energy stock as reported by the NYSE.

All quarterly retainer and meeting attendance fees were paid on the last business day of March, June, September and December. Nonemployee directors were reimbursed for actual travel and out-of-pocket expenses incurred in connection with their services. Directors who also served as employees of the Company did not receive compensation for their service on the Board or any committees.

Nonemployee directors were eligible to participate in the Company's matching gift program on the same terms as all Puget Energy employees. Under this program, the Company would match up to a total of $300 a year in contributions by a director to non-profit organizations which had an IRS 501(c)(3) tax exempt status and was located in and served the people of PSE’s service territory in Washington State.

**Deferral of Compensation.** Nonemployee directors could defer receipt of all or a part of their quarterly retainer fees that were required to be paid in Puget Energy stock into unfunded deferred stock unit accounts under the Company's Nonemployee Director Plan. Deferred stock units earned the equivalent of dividends, which were credited as additional deferred stock units. Nonemployee directors did not have the right to vote or transfer the deferred stock units.

Nonemployee directors could also elect to defer all or a part of their fees payable in cash under the Company's Deferred Compensation Plan for Nonemployee Directors. Nonemployee directors could allocate these deferrals into one or more “measurement funds,” which included an interest crediting fund, an equity index fund, a bond index fund and a Puget Energy stock fund. Nonemployee directors were permitted to make changes in measurement fund allocations quarterly. Amounts allocated to the Puget Energy stock fund were treated as deferred stock units that earned the equivalent of dividends, which were credited as additional deferred stock units. Nonemployee directors did not have the right to vote or transfer the deferred stock units.

As a result of the delisting of Puget Energy stock following the completion of the merger on February 6, 2009, the Puget Energy stock unit accounts in the Nonemployee Director Plan were transferred as stock accounts to the Company's Deferred Compensation Plan for Nonemployee Directors, and all amounts allocated to stock accounts in that plan were reallocated to other accounts in accordance with the director's direction or, if none, into an interest crediting tracking fund.

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

### SECURITY OWNERSHIP OF DIRECTORS, EXECUTIVE OFFICERS AND CERTAIN BENEFICIAL OWNERS

The following tables show the number of shares of common stock beneficially owned as of March 2, 2009 by each person or group that we know owns more than 5.0% of Puget Energy’s and PSE’s common stock. No director, executive officer or executive officer named in the Summary Compensation Table in Item 11 of Part III of this report owns any of the outstanding shares of common stock of Puget Energy or PSE. Puget Equico LLC and its affiliates beneficially own 100.0% of the outstanding common stock of Puget Energy. Puget Energy holds 100% of the outstanding common stock of PSE. Percentage of beneficial ownership is based on 200 shares of Puget Energy common stock and 85,903,791 shares of Puget Sound Energy common stock outstanding as of March 2, 2009.

**BENEFICIAL OWNERSHIP TABLE OF PUGET ENERGY AND PSE**

| | NUMBER OF BENEFICIALLY OWNED SHARES | |
|---|---|---|
| NAME | PUGET ENERGY | PSE |
| Puget Equico LLC and affiliates | 200 [1, 2] | -- |
| Puget Energy | -- | 85,903,791[3] |

1 *Information presented above and in this footnote is based on Amendment No. 2 to Schedule 13D/A filed on February 13,2009 (the Schedule 13D) by Puget Equico LLC (Puget Equico), Puget Intermediate Inc. (Puget Intermediate), Puget Holdings LLC (Puget Holdings and together with Puget Intermediate, the Parent Entities), MIP Padua Holdings, GP (MIP), MIP Washington Holdings, L.P. (MIP II), Macquarie FSS Infrastructure Trust (MFIT), Padua MG Holdings LLC (PMGH), CPP Investment Board (USRE II) Inc. (CPP), Padua Investment Trust (PIT), PIP2PX (Pad) Ltd. (PIP2PX) and PIP2GV (Pad) Ltd. (PIP2GV) and together with all the preceding entities other than the Puget Equico and the Parent Entities, the Padua Investors). Puget Equico is a wholly owned subsidiary of Puget Intermediate, Puget Intermediate is a wholly owned subsidiary of Puget Holdings and the Padua Investors are the direct or indirect owners of Puget Holdings. The Parent Entities and Padua Investors are the direct or indirect owners of Puget Equico. Although the Parent Entities and Padua Investors do not own any shares of Puget Energy directly, Puget Equico, the Parent Entities and Padua Investors may be deemed to be members of a "group," within the meaning of Section 13(d)(3) of the Securities Exchange Act of 1934, as amended. Accordingly, each such entity may be deemed to beneficially own the 200 shares of Puget Energy common stock owned by Puget Equico. Such shares of common stock constitute 100% of the issued and outstanding shares of common stock of Puget Energy. Under Section 13(d)(3) of the Exchange Act and based on the number of shares outstanding, Puget Equico, the Parent Entities and the Padua Investors may be deemed to have shared power to vote and shared power to dispose of such shares of Puget Energy common stock that may be beneficially owned by Puget Equico. However, each of Puget Equico, the Parent Entities and the Padua Investors expressly disclaims beneficial ownership of such shares of common stock other than those shares held directly by such entity. According to the Schedule 13D, as of February 13, 2009:*

- *The address of the principal office of Puget Holdings is 125 West 55th Street, Level 22, New York, NY 10019.*
- *The address of the principal office of Puget Intermediate and Puget Equico is The PSE Building, 10885 NE 4th Street, Bellevue, WA 98009.*
- *The address of the principal office of MIP and MIP II is 125 West 55th Street, Level 22, New York, NY 10019.*
- *The address of the principal office of MFIT is Level 11, 1 Martin Place, Sydney, Australia NSW 2000.*
- *The address of the principal office of PMGH is 125 West 55th Street, Level 22, New York, NY 10019.*
- *The address of the principal office of CPP is One Queen Street East, Suite 2600, P.O. Box 101, Toronto, Ontario, Canada M5C 2W5.*
- *The address of the principal office of PIT is c/o its Trustee 6860141 Canada Inc., British Columbia Investment Management Corporation, Sawmill Point, Suite 301-2940 Jutland Road, Victoria, British Columbia, Canada V8T 5K6.*
- *The address of the principal office of PIP2PX and PIP2GV is 340 Terrace Building, 9515-107 Street, Edmonton, Alberta, Canada T5K 2C3.*

2 *Pursuant to that certain Pledge Agreement dated as of February 6, 2009, made by Puget Equico LLC to Barclays Bank PLC, as collateral agent the outstanding stock of Puget Energy held by Puget Equico was pledged by Puget Equico to secure the obligations of Puget Energy under the Credit Agreement dated as of May 16, 2008 among Puget Merger Sub Inc., as Borrower, Barclays Bank PLC, as Facility Agent, the other agents party thereto, and the lender party thereto (which agreement was subsequently assumed by Puget Energy.*

3 *Pursuant to that certain Borrower's Security Agreement dated as of February 6, 2009, the outstanding stock of PSE held by Puget Energy was pledged by Puget Energy to secure its obligations under the Credit Agreement dated as of May 16, 2008 among Puget Merger Sub Inc,. as Borrower, Barclays Bank PLC, as Facility Agent, the other agents party thereto, and the lender party thereto (which agreement was subsequently assumed by Puget Energy.*

**EQUITY COMPENSATION PLAN INFORMATION**

In connection with the merger of Puget Energy with Puget Holdings, which was completed on February 6, 2009, all compensation plans under which equity securities were authorized for issuance have been terminated.

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

**TRANSACTIONS WITH RELATED PERSONS**

Our Boards of Directors have adopted a written policy for the review and approval or ratification of related person transactions. Under the policy, our directors and executive officers are expected to disclose to our Chief Compliance Officer the material facts of any transaction that could be considered a related person transaction promptly upon gaining knowledge of the transaction. A related person transaction is generally defined as any transaction required to be disclosed under Item 404(a) of Regulation S-K, the SEC's related person transaction disclosure rule.

Any transaction reported to the Chief Compliance Officer will be reviewed according to the following procedures:

- If the Chief Compliance Officer determines that disclosure of the transaction is not required under the SEC's related person transaction disclosure rule, the transaction will be deemed approved and will be reported to the Audit Committee.
- If disclosure is required, the Chief Compliance Officer will submit the transaction to the Chair of the Audit Committee, who will review and, if authorized, will determine whether to approve or ratify the transaction. The Chair is authorized to approve or ratify any related person transaction involving an aggregate amount of less than $1.0 million or when it would be impracticable to wait for the next Audit Committee meeting to review the transaction.
- If the transaction is outside the Chair's authority, the Chair will submit the transaction to the Audit Committee for review and approval or ratification.

When determining whether to approve or ratify a related person transaction, the Chair of the Audit Committee or the Audit Committee, as applicable, will review relevant facts regarding the related person transaction, including:

- The extent of the related person's interest in the transaction;
- Whether the terms are comparable to those generally available in arms' length transactions; and
- Whether the related person transaction is consistent with the best interests of the Company.

If any related person transaction is not approved or ratified, the Committee may take such action as it may deem necessary or desirable in the best interests of the Company and its shareholders.

Each of the directors of Puget Energy and PSE (with the exception of Herbert Simon, who only serves on the Board of Directors of PSE) are on the Board of Managers of Puget Holdings, which was a party to that certain merger agreement entered into by Puget Holdings and Puget Energy, pursuant to which Puget Holdings acquired Puget Energy for $30.00 per share.

## BOARD OF DIRECTORS AND CORPORATE GOVERNANCE

### INDEPENDENCE OF THE BOARD

The Boards of Puget Energy and PSE have reviewed the relationships between Puget Energy and PSE (and their respective subsidiaries) and each of their respective directors, including those directors serving during the fiscal year ended December 31, 2008 and prior to the closing of the merger on February 6, 2009. Based on this review, the Boards have determined that all of the directors serving prior to the closing of the merger, other than Stephen P. Reynolds, Puget Energy's Chairman, President and CEO, were independent under the NYSE corporate governance listing standards and Puget Energy's Corporate Governance Guidelines in during that time. In addition, the Boards have determined that of the members constituting the Boards following the closing of the merger, William S. Ayer (member of the Boards of both Puget Energy and PSE) and Herbert B. Simon (member of the Board of PSE) are independent under the New York Stock Exchange (NYSE) corporate governance listing standards and also meet the definition of an "Independent Director" under the Company's Amended and Restated Bylaws. Under the Amended and Restated Bylaws of Puget Energy and PSE, an Independent Director is a director who: (a) shall not be a member of Puget Holdings (referred to as a Holdings Member) or an affiliate of any Holdings Member (including by way of being a member, stockholder, director, manager, partner, officer or employee of any such member), (b) shall not be an officer or employee of PSE, (c) shall be a resident of the state of Washington, and (d) if and to the extent required with respect to any specific director, shall meet such other qualifications as may be required by any applicable regulatory authority for an independent director or manager.

In making these independence determinations, the Boards have established a categorical standard that a director's independence is not impaired solely as a result of the director, or a company for which the director or an immediate family member of the director serves as an executive officer, making payments to PSE for power or natural gas provided by PSE at rates fixed in conformity with law or governmental authority, unless such payments would automatically disqualify the director under the NYSE's corporate governance listing standards. The Board has also established a categorical standard that a director's independence is not impaired if a director is a director, employee or executive officer of another company that makes payments to or receives payments from Puget Energy, PSE, or any of their affiliates, for property or services in an amount which is less than the greater of $1.0 million or one percent of such other company's consolidated gross revenues, determined for the most recent fiscal year. These categorical standards will not apply, however, to the extent that Puget Energy or PSE would be required to disclose an arrangement as a related person transaction pursuant to Item 404 of Regulation S-K.

The Boards considered all relationships between its directors and Puget Energy and PSE (and there respective subsidiaries), including some that are not required to be disclosed in this report as related-person transactions. Messrs. Ayer and Simon, and former directors Cole and Moriguchi serve as directors or officers of, or otherwise have a financial interest in, entities that make payments to PSE for energy services provided to those entities at tariff rates established by the Washington Utilities and Transportation Commission. These transactions fall within the first categorical independence standard described above. In addition, PSE has entered into transactions with entities for whom Mr. Simon and former directors Cole and Frank serve as directors or officers, or in which they otherwise have a financial interest, that involve amounts that are less than the greater of $1.0 million or 1% of those entities' consolidated gross revenues. These transactions fall within the second categorical standard described above. Because these relationships either fall within the Board's categorical independence standards or involve an amount that is not material to Puget Energy or the other entity, the Board has concluded that none of these relationships impair the independence of the applicable directors.

***EXECUTIVE SESSIONS***

Non-management directors meet in executive session on a regular basis, generally on the same date as each scheduled Board meeting. Mr. Ayer, who is not a member of management, presides over the executive sessions. Shareholders and other interested parties may communicate with the non-management directors of the Board through the procedures described in Item 10 of Part III of this annual report under the section "Communications with the Board."

## 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:

| | 2008 | | 2007 | |
|---|---|---|---|---|
| (DOLLARS IN THOUSANDS) | PUGET ENERGY | PSE | PUGET ENERGY | PSE |
| Audit fees[1] | $ 1,815 | $ 1,815 | $ 1,695 | $ 1,680 |
| Audit related fees[2] | 116 | 116 | 108 | 108 |
| Tax fees[3] | 150 | 150 | 16 | 16 |
| Total | $ 2,081 | $ 2,081 | $ 1,819 | $ 1,804 |

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 Company's Forms 10-Q and consents and reviews of documents filed with the Securities and Exchange Commission. The 2008 fees are estimated and include an aggregate amount of $1.3 million billed to Puget Energy and PSE, through December 2008. The 2007 fees include an aggregate amount of $1.4 million and $1.4 million billed to Puget Energy and PSE, respectively, through December 31, 2007.*

2 *Consists of employee benefit plan audits and due diligence reviews.*

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 registered public accounting firm. The policies are designed to ensure that the provision of these services does not impair the firm's independence. Under the policies, unless a type of service to be provided by the independent registered public accounting firm 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 2008 and 2007, 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 65.

2) *Financial Statement Schedules*. Financial Statement Schedules of the Company located on page 139, as required for the years ended December 31, 2008, 2007 and 2006, consist of the following:

   I. Condensed Financial Information of Puget
   II. Valuation of Qualifying Accounts

3) Exhibits - see index on page 177.

## 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, INC. |
|---|---|
| /s/ Stephen P. Reynolds | /s/ Stephen P. Reynolds |
| Stephen P. Reynolds | Stephen P. Reynolds |
| President and Chief Executive Officer | President and Chief Executive Officer |
| Date: March 3, 2009 | Date: March 3, 2009 |

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<br>(Puget Energy and PSE unless otherwise noted) | DATE |
|---|---|---|
| /s/ Stephen P. Reynolds<br>(Stephen P. Reynolds) | President and<br>Chief Executive Officer | March 3, 2009 |
| /s/ Eric M. Markell<br>(Eric M. Markell) | Executive Vice President and<br>Chief Financial Officer | |
| /s/ James W. Eldredge<br>(James W. Eldredge) | Vice President, Controller<br>and Chief Accounting Officer | |
| /s/ William S. Ayer<br>(William S. Ayer) | Chairman and Director | |
| /s/ Graeme Bevans<br>(Graeme Bevans) | Director | |
| /s/ Andrew Chapman<br>(Andrew Chapman) | Director | |
| /s/ Alan W. James<br>(Alan W. James) | Director | |
| /s/Alan Kadic<br>(Alan Kadic) | Director | |
| /s/ Christopher J. Leslie<br>(Christopher J. Leslie) | Director | |
| /s/ William R. McKenzie<br>(William R. McKenzie) | Director | |

| | |
|---|---|
| /s/ Lincoln Webb<br>(Lincoln Webb) | Director |
| /s/ Mark Wong<br>(Mark Wong) | Director |
| /s/ Herbert B. Simon<br>(Herbert B. Simon) | Director of PSE only |

## 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.

| | |
|---|---|
| 2.1 | Agreement and Plan of Merger, dated October 25, 2007, by and among Puget Energy, Inc., Padua Holdings LLC, Padua Intermediate Holdings Inc. and Padua Merger Sub Inc. (incorporated herein by reference to Exhibit 2.1 to Puget Energy's Current Report on Form 8-K, dated October 25, 2007, Commission File No. 1-16305). |
| 3(i).1 | Amended Articles of Incorporation of Puget Energy (incorporated herein by reference to Exhibit 3.1 to Puget Energy's Current Report on Form 8-K, dated February 6, 2009, Commission File No. 1-16305). |
| 3(i).2 | Amended and Restated Articles of Incorporation of Puget Sound Energy, Inc. (incorporated herein by reference to Exhibit 3.2 to Puget Sound Energy's Current Report on Form 8-K, dated February 6, 2009, Commission File No. 1-4393). |
| 3(ii).1 | Amended and Restated Bylaws of Puget Energy dated February 6, 2009 (incorporated herein by reference to Exhibit 3.3 to Puget Energy's Current Report on Form 8-K, Commission File No. 1-16305). |
| 3(ii).2 | Amended and Restated Bylaws of Puget Sound Energy, Inc. dated February 6, 2009 (incorporated herein by reference to Exhibit 3.4 to Puget Sound Energy's Current Report on Form 8-K, Commission File No. 1-4393). |
| 4.1 | Indenture between Puget Sound Energy, Inc. and U.S. Bank National Association (as successor to State Street Bank and Trust Company) defining the rights of the holders of Puget Sound Energy's senior notes (incorporated herein by reference to Exhibit 4-a to Puget Sound Energy's Report on Form 10-Q for the quarter ended June 30, 1998, Commission File No. 1-4393). |
| 4.2 | First, Second, Third and Fourth Supplemental Indentures defining the rights of the holders of Puget Sound Energy's senior notes (incorporated herein by reference to Exhibit 4-b to Puget Sound Energy's Report on Form 10-Q for the quarter ended June 30, 1998, Commission File No. 1-4393; Exhibit 4.26 to Puget Sound Energy's Current Report on Form 8-K, dated March 4, 1999, Commission File No. 1-4393; Exhibit 4.1 to Puget Sound Energy's Current Report on Form 8-K, dated November 2, 2000, Commission File No. 1-4393; and Exhibit 4.1 to Puget Sound Energy's Current Report on Form 8-K, dated May 28, 2003, Commission File No. 1-4393). |
| 4.3 | Fortieth through Eighty-sixth Supplemental Indentures defining the rights of the holders of Puget Sound Energy's Electric Utility First Mortgage Bonds (incorporated herein by reference to 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; Exhibit 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 Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 1985, Commission File No. 1-4393; Exhibits (4)(a) and (4)(b) to Puget Sound Energy's Current Report on Form 8-K, dated April 22, 1986, Commission File No. 1-4393; Exhibit (4)(b) to Puget Sound Energy's Current Report on Form 8-K, dated September 5, 1986, Commission File No. 1-4393; Exhibit (4)-b to Puget Sound Energy's Report on Form 10-Q for the quarter ended September 30, 1986, Commission File No. 1-4393; Exhibit (4)-c to Registration No. 33-18506; Exhibit (4)-b to Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 1989, Commission File No. 1-4393; Exhibit (4)-b to Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 1990, Commission File No. 1-4393; Exhibits (4)-d and (4)-e 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-c to Puget Sound Energy's Report on Form 10-Q for the quarter ended June 20, 1998, Commission File No. 1-4393; Exhibit 4.27 to Puget Sound Energy's Current Report on Form 8-K, dated March 4, 1999, Commission File No. 1-4393; Exhibit 4.2 to Puget Sound Energy's Current Report on Form 8-K, dated November 2, 2000, Commission File No. 1-4393; Exhibit 4.2 to Puget Sound Energy's Current Report on Form 8-K, dated May 28, 2003, Commission File No. 1-4393; Exhibit 4.28 to Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2004, Commission File No. 1-4393; Exhibit 4.1 to Puget Sound Energy's Current Report on Form 8-K, dated May 23, 2005, Commission File No. 1-4393; Exhibit 4.30 to Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2005, Commission File No. 1-4393); Exhibit 4.4 to Post-Effective Amendment No. 2 to Puget Sound Energy's Registration Statement on Form S-3, filed February 9, 2009, Registration No. 333-132497-01; Exhibit 4.1 to Puget Sound Energy's Current Report on Form 8-K, dated September 13, 2006, Commission File No. 1-4393; Exhibit 4.1 to Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2007, Commission File No. 1-4393; and Exhibit 4.5 to Post-Effective Amendment No. 2 to Puget Sound Energy's Registration Statement on Form S-3, filed February 9, 2009, Registration No. 333-132497-01). |

4.4 Indenture of First Mortgage, dated as of April 1, 1957, defining the rights of the holders of Puget Sound Energy's Gas Utility First Mortgage Bonds (incorporated herein by reference to Washington Natural Gas Company Exhibit 4-B, Registration No. 2-14307).

4.5 First Supplemental Indenture to the Gas Utility First Mortgage, dated as of October 1, 1959 (incorporated herein by reference to Washington Natural Gas Company Exhibit 4-D, Registration No. 2-17876).

4.6 Sixth and Seventh Supplemental Indentures to the Gas Utility First Mortgage, dated as of August 1, 1966 and February 1, 1967, respectively (incorporated herein by reference to Washington Natural Gas Company Exhibit to Form 8-K for month of August 1966, File No. 0-951; and Exhibit 4-M, Registration No. 2-27038).

4.7 Sixteenth Supplemental Indenture to the Gas Utility First Mortgage, dated as of June 1, 1977 (incorporated herein by reference to Washington Natural Gas Company Exhibit 6-05, Registration No. 2-60352).

4.8 Seventeenth Supplemental Indenture to the Gas Utility First Mortgage, dated as of August 9, 1978 (incorporated herein by reference to Washington Energy Company Exhibit 5-K.18, Registration No. 2-64428).

4.9 Twenty-second Supplemental Indenture to the Gas Utility First Mortgage, dated as of July 15, 1986 (incorporated herein by reference to Exhibit 4-B.20 to Washington Natural Gas Company's Report on Form 10-K for the fiscal year ended September 30, 1986, Commission File No. 0-951).

4.10 Twenty-seventh Supplemental Indenture to the Gas Utility First Mortgage, dated as of September 1, 1990 (incorporated herein by reference to Exhibit 4.12 to Post-Effective Amendment No. 2 to Puget Sound Energy's Registration Statement on Form S-3, filed February 9, 2009, Registration No. 333-132497-01).

4.11 Twenty-eighth through Thirty-sixth Supplemental Indentures to the Gas Utility First Mortgage (incorporated herein by reference to Exhibit 4-A to Washington Natural Gas Company's Report on Form 10-Q for the quarter ended March 31, 1993, Commission File No. 0-951; Exhibit 4-A to Washington Natural Gas Company's Registration Statement on Form S-3, Registration No. 33-49599; Exhibit 4-A to Washington Natural Gas Company's Registration Statement on Form S-3, Registration No. 33-61859; Exhibit 4.30 to Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2002, Commission File No. 1-4393; Exhibits 4.22 and 4.23 to Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2005, Commission File No. 1-4393; Exhibits 4.22 and 4.23 to Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2007, Commission File No. 1-4393; and Exhibit 4.14 to Post-Effective Amendment No. 2 to Puget Sound Energy's Registration Statement on Form S-3, filed February 9, 2009, Registration No. 333-132497-01).

4.12 Unsecured Debt Indenture, dated as of May 18, 2001, between Puget Sound Energy, Inc. and The Bank of New York Trust Company, N.A. (as successor to Bank One Trust Company, N.A.) defining the rights of the holders of Puget Sound Energy's unsecured debentures (incorporated herein by reference to Exhibit 4.3 to Puget Sound Energy's Current Report on Form 8-K, dated May 18, 2001, Commission File No. 1-4393).

4.13 Second Supplemental Indenture to the Unsecured Debt Indenture, dated June 1, 2007, between Puget Sound Energy, Inc. and The Bank of New York Trust Company, N.A. defining the rights of Puget Sound Energy's Series A Enhanced Junior Subordinated Notes due June 1, 2067 (incorporated herein by reference to Exhibit 4.1 to Puget Sound Energy's Current Report on Form 8-K, dated May 30, 2007, Commission File No. 1-4393).

4.14 Form of Replacement Capital Covenant of Puget Sound Energy, Inc. (incorporated herein by reference to Exhibit 4.2 to Puget Sound Energy's Current Report on Form 8-K, dated May 30, 2007, Commission File No. 1-4393).

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

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

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 Puget Sound Energy, Inc., relating to the Rocky Reach Project (incorporated herein by reference to 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 Puget Sound Energy, Inc., relating to the Wells Development (incorporated herein by reference to 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 Puget Sound Energy, Inc., relating to the Rocky Reach Project (incorporated herein by reference to 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 Puget Sound Energy, Inc., relating to the Rocky Reach Project (incorporated herein by reference to 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 Puget Sound Energy, Inc., relating to the Priest Rapids Project (incorporated herein by reference to Exhibit 4-d to Registration No. 2-13347).

10.6 First Amendment to Power Sales Contract dated as of August 5, 1958 between Puget Sound Energy, Inc. and Public Utility District No. 2 of Grant County, Washington, relating to the Priest Rapids Development (incorporated herein by reference to 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 Puget Sound Energy, Inc., relating to the Wanapum Development (incorporated herein by reference to 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 Puget Sound Energy, Inc., relating to the Wanapum Development (incorporated herein by reference to 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 Puget Sound Energy, Inc., relating to the Wells Development (incorporated herein by reference to 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 Puget Sound Energy, Inc. (incorporated herein by reference to 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 Puget Sound Energy, Inc. (incorporated herein by reference to Exhibit 5-c to Registration No. 2-45702).

10.12 Contract dated June 19, 1974 between Puget Sound Energy, Inc. and P.U.D. No. 1 of Chelan County (incorporated herein by reference to Exhibit D to Form 8-K dated July 5, 1974).

10.13 Transmission Agreement dated April 17, 1981 between the Bonneville Power Administration and Puget Sound Energy, Inc. (Colstrip Project) (incorporated herein by reference to Exhibit (10)-55 to 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) (incorporated herein by reference to Exhibit (10)-56 to 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 Puget Sound Energy, Inc. and other Owners of the Colstrip Project (Colstrip 3 and 4) (incorporated herein by reference to Exhibit (10)-57 to 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 Puget Sound Energy, Inc. and Owners of the Colstrip Project (incorporated herein by reference to Exhibit (10)-58 to 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 Puget Sound Energy, Inc. and Owners of Colstrip 1 and 2, and 3 and 4 (incorporated herein by reference to Exhibit (10)-59 to 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 Puget Sound Energy, Inc. (Rocky Reach Project) (incorporated herein by reference to Exhibit (10)-66 to 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 Puget Sound Energy, Inc. (Rock Island Project) (incorporated herein by reference to Exhibit (10)-74 to 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 Puget Sound Energy, Inc. dated as of October 1, 1989 (incorporated herein by reference to Exhibit (10)-4 to 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 Puget Sound Energy, Inc. (incorporated herein by reference to Exhibit (10)-91 to 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 Puget Sound Energy, Inc. (incorporated herein by reference to Exhibit (10)-4 to 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 Puget Sound Energy, Inc. (incorporated herein by reference to Exhibit (10)-1 to 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 Puget Sound Energy, Inc. (incorporated herein by reference to Exhibit (10)-107 to 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 Puget Sound Energy, Inc. (incorporated herein by reference to Exhibit (10)-108 to 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 Puget Sound Energy, Inc. (BPA Contract No. DE-MS79-94BP93947) (incorporated herein by reference to Exhibit 10.115 to 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 Puget Sound Energy, Inc. (BPA Contract No. DE-MS79-94BP94521) (incorporated herein by reference to Exhibit 10.116 to 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 (incorporated herein by reference to Exhibit 10-E.2 to Washington Natural Gas Company's Form 10-K for the fiscal year ended September 30, 1995, Commission File No. 1-11271).

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 (incorporated herein by reference to Exhibit 10-P to Washington Natural Gas Company's Form 10-K for the fiscal year ended September 30, 1994, Commission File No. 1-11271).

10.30 Product Sales Contract dated December 13, 2001 and Amendment No. 1 thereto, between Public Utility District No. 2 of Grant County, Washington, and Puget Sound Energy, Inc., relating to the Priest Rapids Project (incorporated herein by reference to Exhibit 10-1 to Puget Sound Energy's Report on Form 10-Q for the quarter ended June 30, 2002, File No. 1-4393).

10.31 Reasonable Portion Power Sales Contract dated December 13, 2001 and Amendment No. 1 thereto, between Public Utility District No. 2 of Grant County, Washington, and Puget Sound Energy, Inc., relating to the Priest Rapids Project (incorporated herein by reference to Exhibit 10-2 to Puget Sound Energy's Report on Form 10-Q for the quarter ended June 30, 2002, Commission File No. 1-4393).

10.32 Additional Products Sales Agreement dated December 13, 2001, and Amendment No. 1 thereto, between Public Utility District No. 2 of Grant County, Washington, and Puget Sound Energy, Inc., relating to the Priest Rapids Project (incorporated herein by reference to Exhibit 10.3 to Puget Sound Energy's Report on Form 10-Q for the quarter ended June 30, 2002, Commission File No. 1-4393).

10.33 Credit Agreement dated as of May 16, 2008 among Puget Merger Sub Inc., as Borrower, Barclays Bank PLC, as Facility Agent, the other agents party thereto, and the lenders party thereto (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K, dated February 6, 2009, Commission File No. 1-16305 and 1-4393).

10.34 Credit Agreement dated as of February 6, 2009 among Puget Sound Energy, Inc., as Borrower, Barclays Bank PLC, as Facility Agent, the other agents party thereto, and the lenders party thereto (incorporated herein by reference to Exhibit 10.2 to Puget Sound Energy's Current Report on Form 8-K, dated February 6, 2009, Commission File No. 1-4393).

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

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

** 10.37 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 (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K, dated February 14, 2006, Commission File Nos. 1-16305 and 1-4393).

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| ** 10.38 | Third Amendment dated February 28, 2008 to employment agreement with S.P. Reynolds, Chief Executive Officer and President, dated as of January 1, 2002 and amended as of February 9, 2006 (incorporated herein by reference to Exhibit 10.44 to Puget Energy's Report on Form 10-K for the fiscal year ended December 31, 2008, Commission File No. 1-16305 and 1-4393). |
| *** 10.39 | Puget Sound Energy, Inc. Amended and Restated Supplemental Executive Retirement Plan effective January 1, 2009. |
| *** 10.40 | Puget Sound Energy, Inc. Amended and Restated Deferred Compensation Plan for Key Employees effective January 1, 2009. |
| *** 10.41 | Puget Sound Energy, Inc. Amended and Restated Deferred Compensation Plan for Nonemployee Directors effective January 1, 2009. |
| ** 10.42 | Summary of Director Compensation (incorporated herein by reference to Exhibit 10.51 to Puget Energy's and Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2006, Commission File No. 1-16305 and 1-4393). |
| ** 10.43 | Form of Amended and Restated Change of Control Agreement between Puget Sound Energy, Inc. and Executive Officers (incorporated herein by reference to Exhibit 10.3 to the Current Report on Form 8-K, dated February 14, 2006, Commission File Nos. 1-4393). |
| ** 10.44 | Summary of Severance Benefit for B.A. Valdman, Senior Vice President Finance and Chief Financial Officer (incorporated herein by reference to Exhibit 10.55 to Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2006, Commission File No. 1-4393). |
| *** 10.45 | Puget Sound Energy, Inc. Supplemental Death Benefit Plan for Executive Employees, effective October 1, 2000, as amended. |
| *** 10.46 | Puget Sound Energy, Inc. Supplemental Death Benefit Plan for Executive Employees, effective January 1, 2002, as amended. |
| *** 10.47 | Puget Sound Energy, Inc. Supplemental Disability Plan for Executive Employees, effective October 1, 2000, as amended. |
| *** 10.48 | Puget Sound Energy, Inc. Supplemental Death Benefit Plan for Executive Employees, effective November 1, 2007, as amended. |
| * 12.1 | Statement setting forth computation of ratios of earnings to fixed charges of Puget Energy, Inc. (2004 through 2008). |
| * 12.2 | Statement setting forth computation of ratios of earnings to fixed charges of Puget Sound Energy, Inc. (2004 through 2008). |
| * 21.1 | Subsidiaries of Puget Energy, Inc. |
| * 21.2 | Subsidiaries of Puget Sound Energy, Inc. |
| * 23.1 | Consent of PricewaterhouseCoopers LLP. |
| * 31.1 | Certification of Puget Energy, Inc. - 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, Inc. - Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 – Eric M. Markell. |
| * 31.3 | Certification of Puget Sound Energy, Inc. - 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, Inc. – Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 – Eric M. Markell. |
| * 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 – Eric M. Markell. |

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* *Filed herewith.*

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

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