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, 2012

OR

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

For the transition period from ___________ to ___________

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

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

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

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

Indicate by check mark whether the registrants: (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.

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

Indicate by check mark whether the registrants have submitted electronically and posted on its corporate websites, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to post such files).

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

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

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DEFINITIONS

AFUDC	Allowance for Funds Used During Construction
aMW	Average Megawatt
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
BPA	Bonneville Power Administration
Colstrip	Colstrip, Montana coal-fired steam electric generation facility
Dth	Dekatherm (one Dth is equal to one MMBtu)
EBITDA	Earnings Before Interest, Tax, Depreciation and Amortization
EPA	Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	Generally Accepted Accounting Principles
GHG	Greenhouse gases
Goldendale	Goldendale electric generating facility
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
kW	Kilowatt
kWh	Kilowatt Hour (one kWh equals one thousand watt hours)
LIBOR	London Interbank Offered Rate
LNG	Liquefied Natural Gas
LTI Plan	Long-Term Incentive Plan
Mint Farm	Mint Farm Electric Generating Station
MMBtu	One Million British Thermal Unit
MW	Megawatt (one MW equals one thousand kW)
MWh	Megawatt Hour (one MWh equals one thousand kWh)
NAESB	North American Energy Standards Board
NERC	North American Electric Reliability Corporation
Ninth Circuit	United States Court of Appeals for the Ninth Circuit
NOAA	National Oceanic and Atmospheric Administration
NPNS	Normal Purchase Normal Sale
NWP	Northwest Pipeline GP
NYSE	New York Stock Exchange
OCI	Other Comprehensive Income
PCA	Power Cost Adjustment
PCORC	Power Cost Only Rate Case
PGA	Purchased Gas Adjustment
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
REC	Renewable Energy Credit
REP	Residential Exchange Program
SEC	United States Securities and Exchange Commission
SERP	Supplemental Executive Retirement Plan
Tenaska	Tenaska Power Fund, L.P.
VIE	Variable Interest Entity
Washington Commission	Washington Utilities and Transportation Commission
Wild Horse	Wild Horse wind project

FORWARD-LOOKING STATEMENTS

Puget Energy, Inc. (Puget Energy) and Puget Sound Energy, Inc. (PSE) include 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," "continues," "could," "estimates," "expects," "future," "intends," "may," "might," "plans," "potential," "predicts," "projects," "should," "will likely result," "will continue" or similar expressions are intended to identify certain of these forward-looking statements.

Forward-looking statements reflect current expectations and 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 Company 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. Puget Energy and PSE are collectively referred to herein as "the Company."

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, financing, 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, natural gas and electric distribution and transmission facilities, 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, implementation of energy efficiency programs and present or prospective wholesale and retail competition;
- Failure of PSE to comply with the FERC or the Washington Commission standards and/or rules, which could result in penalties based on the discretion of either commission;
- Findings of noncompliance with electric reliability standards developed by the North American Electric Reliability Corporation (NERC) or the Western Electricity Coordinating Council for users, owners and operators of the power system, which could result in penalties;
- Changes in, adoption of and compliance with laws and regulations, including decisions and policies concerning the environment, climate change, greenhouse gas or other emissions or byproducts of electric generation (including coal ash or other substances), natural resources, and fish and wildlife (including the Endangered Species Act) as well as the risk of litigation arising from such matters, whether involving public or private claimants or regulatory investigative or enforcement measures;
- The ability to recover costs arising from changes in enacted federal, state or local tax laws 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;
- Inability to realize deferred tax assets and use production tax credits (PTCs) due to insufficient future taxable income;
- Accidents or natural disasters, such as hurricanes, windstorms, earthquakes, floods, fires and landslides, which can interrupt service and lead to lost revenue, 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 or counterparties extending credit to PSE without collateral posting requirements;
- 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, 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 climate or weather conditions in the Pacific Northwest, which could have effects on customer usage and PSE's revenue and expenses;

- Regional or national 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 hydrological conditions, which can impact streamflow and PSE's ability to generate electricity from hydroelectric facilities;
- Electric plant generation and transmission system 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 generation 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;
- Industrial, commercial and residential growth and demographic patterns in the service territories of PSE;
- General economic conditions in the Pacific Northwest, which may impact customer consumption or affect PSE's accounts receivable;
- The loss of significant customers, changes in the business of significant customers or the condemnation of PSE's facilities as a result of municipalization or other government action or negotiated settlement, 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 Puget Energy's or PSE's credit ratings, which may have an adverse impact on the availability and cost of capital for Puget Energy or PSE generally, or the failure to comply with the covenants in Puget Energy's or PSE's credit facilities, which would limit the Company's ability to utilize such facilities for capital; and
- Deteriorating values of the equity, fixed income and other markets which could significantly impact the value of investments of PSE's retirement plan, post-retirement medical benefit plan trusts and the funding of obligations thereunder.

Any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by law, the Company undertakes 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 is an energy services holding company incorporated in the state of Washington in 1999. All of its operations are conducted through its subsidiary, 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 including Macquarie Infrastructure Partners I, Macquarie Infrastructure Partners II, Macquarie Capital Group Limited, FSS Infrastructure Trust, the Canada Pension Plan Investment Board (CPPIB), the British Columbia Investment Management Corporation and the Alberta Investment Management Corporation. As a result of the merger, all of Puget Energy's common stock is indirectly owned by Puget Holdings.

Corporate 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.

The following table presents the number of PSE customers as of December 31, 2012 and 2011:

	Electric			Gas		
	December 31,		Percent	December 31,		Percent
	2012	2011	Change	2012	2011	Change
Customers: [1]						
Residential	964,606	959,547	0.5%	710,926	704,134	1.0%
Commercial	120,627	119,610	0.9	54,049	54,106	(0.1)
Industrial	3,541	3,622	(2.2)	2,423	2,475	(2.1)
Other	3,532	3,503	0.8	203	180	12.8
Total	1,092,306	1,086,282	0.6%	767,601	760,895	0.9%

1 *At December 31, 2012 approximately 383,612 customers purchased both electricity and natural gas from PSE.*

During 2012, PSE's billed retail and transportation revenue from electric utility operations were derived 52.8% from residential customers, 40.6% from commercial customers, 5.2% from industrial customers and 1.4% from other customers. PSE's retail revenue from natural gas utility operations were derived 66.5% from residential customers, 29.2% from commercial customers, 2.9% from industrial customers and 1.4% from transportation customers in 2012. During this period, the largest customer accounted for approximately 1.6% of PSE's operating revenue.

PSE is affected by various seasonal weather patterns and therefore, utility revenue 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, 2012, PSE's gross electric utility plant additions were $3.9 billion and retirements were $327.5 million. In the same five-year period, PSE's gross natural gas utility plant additions were $790.5 million and retirements were $111.9 million and PSE's gross common utility plant additions were $330.5 million and retirements were $327.0 million. Gross electric utility plant at December 31, 2012 was approximately $9.0 billion, which consisted of 35.5% distribution, 38.2% generation, 12.2% transmission and 14.1% general plant and other. Gross natural gas utility plant at December 31, 2012 was approximately $3.0 billion, which consisted of 93.0% distribution and 7.0% general plant and other. Gross common utility general and intangible plant at December 31, 2012 was approximately $555.5 million.

Employees

At December 31, 2012, Puget Energy had no employees and PSE had approximately 2,800 full-time employees. Approximately 1,200 PSE employees are represented by the United Association of Plumbers and Pipefitters (UA) and the International Brotherhood of Electrical Workers Union (IBEW). The current contracts with the UA and the IBEW expire September 30, 2013 and March 31, 2014, 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.

Available Information

The information required by Item 101(e) of Regulation S-K is incorporated herein by reference to the material under "Additional Information" in Item 10 Part III of this annual report.

REGULATION AND RATES

PSE is subject to the regulatory authority of: (1) the FERC with respect to the transmission of electricity, the sale of electricity at wholesale, accounting and certain other matters; and (2) the Washington Commission as to retail rates, accounting, the issuance of securities and certain other matters. PSE also must comply with mandatory electric system reliability standards developed by the NERC, the electric reliability organization certified by the FERC, which standards are enforced by the Western Electricity Coordinating Council in PSE's operating territory.

Electric General Rate Case.

On May 20, 2010, PSE filed an accounting petition requesting that the Washington Commission approve: (1) the creation of a regulatory asset account for the prepayments made to the Bonneville Power Administration (BPA) associated with network upgrades to the Central Ferry substation related to the Lower Snake River wind project; (2) the monthly accrual of carrying charges on that regulatory asset at PSE's approved net of tax rate of return; and (3) the ability to provide customers the BPA interest received through a reduction to transmission expense.

The Washington Commission issued an order in 2010 relating to how Renewable Energy Credit (REC) proceeds should be handled for regulatory accounting and ratemaking purposes. The order required REC proceeds net of applicable costs to be recorded as regulatory liabilities and that amounts recorded would accrue interest. In its petition, PSE had sought approval for $21.1 million of REC proceeds to be used as an offset against its California wholesale energy sales regulatory asset. In response to the order, PSE adjusted the carrying value of its regulatory asset in the second quarter of 2010 by $17.8 million (from $21.1 million to $3.3 million), with the $3.3 million then offset against the Company's RECs regulatory liability. The Company's California wholesale energy sales regulatory asset represented unpaid bills for power sold into the markets maintained by the California Independent System Operator during the 2000-2001 California Energy Crisis, the claims of which were settled along with all counterclaims against PSE in a settlement agreement approved by the FERC on July 1, 2009. The Washington Commission ordered that parties provide recommended methods for passing back the remaining deferred proceeds. The Commission approved a joint proposal that allowed a portion of the REC proceeds received by PSE to offset the PTCs that had been passed through to customers but have not been used by PSE on its tax return, and after completion of the PTC offset, the Commission allowed PSE to offset the REC liability against rate base and amortize the balance of RECs at the beginning of a given rate year over five years as a credit to cost of service.

On May 7, 2012, the Washington Commission issued its order in PSE's electric general rate case filed in June 2011, approving a general rate increase for electric customers of $63.3 million or 3.2% annually. The rate increases for electric customers became effective May 14, 2012. In its order, the Washington Commission approved a weighted cost of capital of 7.8% and a capital structure that included 48.0% common equity with a return on equity of 9.8%. PSE's requested treatment of the prepayments made to BPA, filed in May 2010, was approved in the order. The final order rejected PSE's proposed conservation savings adjustment. Finally, a new rate rider for Renewable Energy Credits ("RECs") was proposed by settlement of Electric parties and approved by the Washington Commission in the final order. The new rate rider replaced prospectively what was required pursuant to the Commission's orders in 2010.

On April 2, 2010, the Washington Commission issued its order in PSE's consolidated electric rate case filed in May 2009 which approved a general rate increase for electric customers of 3.7% annually, or $74.1 million, effective April 8, 2010. In its order, the Washington Commission approved a weighted cost of capital of 8.1% and a capital structure that included 46.0% common equity with an after-tax return on equity of 10.1%.

For additional information, see Note 3 to the consolidated financial statements included in Item 8 of this report.

Natural Gas Rate Case.

On May 7, 2012, the Washington Commission issued its order in PSE's natural gas general rate case filed in June 2011, approving a general rate increase for natural gas customers of $13.4 million or 1.3% annually. The rate increases for natural gas customers became effective May 14, 2012. In its order, the Washington Commission approved a weighted cost of capital of 7.8% and a capital structure that included 48.0% common equity with a return on equity of 9.8%.

On March 14, 2011, the Washington Commission issued its order authorizing PSE to increase its natural gas general tariff rates by $19.0 million or 1.8% on an annual basis effective April 1, 2011.

On April 2, 2010, the Washington Commission issued its order, effective April 8, 2010, in PSE's natural gas general rate case filed in May 2009, approving a general rate increase of 0.8% annually or $10.1 million. In its order, the Washington Commission approved a weighted cost of capital of 8.1% and a capital structure that included 46.0% common equity with an after-tax return on equity of 10.1%.

For additional information on Gas Rate Case and Purchase Gas Adjustment, see Note 3 to the consolidated financial statements included in Item 8 of this report.

ELECTRIC UTILITY OPERATING STATISTICS

	Year Ended December 31,		
	2012	2011	2010
Generation and purchased power, MWh			
Company-controlled resources	8,999,259	7,881,574	11,220,935
Contracted resources	6,058,460	8,503,356	8,188,156
Non-firm energy purchased	9,117,094	8,586,066	5,683,635
Total generation and purchased power	24,174,813	24,970,996	25,092,726
Less: losses and Company use	(1,638,649)	(1,655,798)	(1,685,890)
Total energy sales, MWh	22,536,164	23,315,198	23,406,836
Electric energy sales, MWh			
Residential	10,744,641	11,045,115	10,672,887
Commercial	9,098,946	9,181,261	9,100,518
Industrial	1,208,801	1,214,232	1,160,588
Other customers	101,070	101,617	99,679
Total energy billed to customers	21,153,458	21,542,225	21,033,672
Unbilled energy sales – net (decrease) increase	(7,228)	(38,355)	(125,288)
Total energy sales to customers	21,146,230	21,503,870	20,908,384
Sales to other utilities and marketers	1,389,934	1,811,328	2,498,452
Total energy sales, MWh	22,536,164	23,315,198	23,406,836
Transportation, including unbilled	1,980,878	2,008,542	1,954,913
Electric energy sales and transportation, MWh	24,517,042	25,323,740	25,361,749
Electric operating revenue by classes (dollars in thousands):			
Residential	$ 1,112,727	$ 1,144,165	$ 1,078,262
Commercial	853,096	853,880	836,957
Industrial	109,083	108,247	103,678
Other customers	19,210	19,122	18,694
Operating revenue billed to customers	2,094,116	2,125,414	2,037,591
Unbilled revenue – net (decrease) increase	6,309	(1,471)	(5,907)
Total operating revenue from customers	2,100,425	2,123,943	2,031,684
Transportation, including unbilled	9,790	10,275	11,000
Sales to other utilities and marketers	23,709	45,725	62,943
Miscellaneous operating revenue	(5,694)	(32,723)	1,842
Total electric operating revenue	$ 2,128,230	$ 2,147,220	$ 2,107,469
Number of customers served (average):			
Residential	961,914	957,205	952,803
Commercial	120,261	119,266	118,595
Industrial	3,600	3,633	3,660
Other	3,504	3,462	3,426
Transportation	17	17	17
Total customers	1,089,296	1,083,583	1,078,501

	Year Ended December 31,		
	2012	2011	2010
Average kWh used per customer:			
Residential	11,170	11,539	11,202
Commercial	75,660	76,981	76,736
Industrial	335,778	334,223	317,100
Other	28,844	29,352	29,095
Average revenue billed per customer:			
Residential	$ 1,157	$ 1,195	$ 1,132
Commercial	7,094	7,159	7,057
Industrial	30,301	29,795	28,327
Other	5,482	5,523	5,457
Average retail revenue per kWh sold:			
Residential	$ 0.1036	$ 0.1036	$ 0.1010
Commercial	0.0938	0.0930	0.0920
Industrial	0.0902	0.0891	0.0893
Other	0.1901	0.1882	0.1875
Average retail revenue per kWh sold	0.0990	0.0982	0.0969
Heating degree days	4,741	5,146	4,549
Percent of normal - NOAA[1] 30-year average	100.5%	107.3%	94.8%
Load factor [2]	59.9%	61.2%	56.7%

[1] *National Oceanic and Atmospheric Administration (NOAA).*

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

ELECTRIC SUPPLY

At December 31, 2012, PSE's electric power resources, which include company-owned or controlled resources as well as those under long-term contract, had a total capacity of approximately 4,977 megawatts (MW). PSE's historical peak load of approximately 4,912 MW occurred on December 10, 2009. 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 for PSE to purchase power than to operate its own generation facilities, PSE will purchase spot market energy.

The following table shows PSE's electric energy supply resources and energy production for the years ended December 31, 2012 and 2011:

	Peak Power Resources At December 31,				Energy Production At December 31,			
	2012		2011		2012		2011	
	MW	%	MW	%	MWh	%	MWh	%
Purchased resources:								
Columbia River PUD contracts [1]	712	14.4%	843	17.8%	3,992,459	17.5%	5,610,424	24.2%
Other hydroelectric [2]	67	1.3	145	3.1	262,714	1.2	655,371	2.8
Other producers [2]	629	12.6	752	16.0	1,678,110	7.4	2,104,612	9.1
Wind	56	1.1	50	1.1	125,148	0.5	132,950	0.6
Short-term wholesale energy purchases [3]	N/A	—	N/A	N/A	7,727,160	33.9	6,774,737	29.3
Total purchased	1,464	29.4%	1,790	38.0%	13,785,591	60.5%	15,278,094	66.0%
Company-controlled resources:								
Hydroelectric	192	3.9%	192	4.1%	746,740	3.3%	683,977	3.0%
Coal	677	13.6	677	14.4	3,809,524	16.7	4,210,583	18.1
Natural gas/oil	1,871	37.6	1,618	34.4	2,620,182	11.5	1,823,138	7.9
Wind	773	15.5	430	9.1	1,822,813	8.0	1,163,876	5.0
Total company-controlled	3,513	70.6%	2,917	62.0%	8,999,259	39.5%	7,881,574	34.0%
Total	4,977	100.0%	4,707	100.0%	22,784,850	100.0%	23,159,668	100.0%

1 *Net of 38 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 and firm contracts are 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 1,389,934 megawatt hours (MWh) and 1,811,328 MWh account for 33.7% and 29.3% of energy production, for 2012 and 2011, respectively.*

Company–Owned Electric Generation Resources

At December 31, 2012, PSE owns or controls the following plants with an aggregate net generating capacity of 3,513 MW:

Plant Name	Plant Type	Net Maximum Capacity (MW) [1]	Year Installed
Colstrip Units 3 & 4 (25% interest)	Coal	370	1984 & 1986
Colstrip Units 1 & 2 (50% interest)	Coal	307	1975 & 1976
Mint Farm	Natural gas combined cycle	297	2007; acquired 2008
Goldendale	Natural gas combined cycle	278	2004; acquired 2007
Frederickson Unit 1 (49.85% interest)	Natural gas combined cycle	136	2002; added duct firing in 2005
Lower Snake River	Wind	343	2012
Wild Horse	Wind	273	2006; added 22 turbines in 2009
Hopkins Ridge	Wind	157	2005; added 4 turbines in 2008
Fredonia Units 1 & 2	Dual-fuel combustion turbines	207	1984
Frederickson Units 1 & 2	Dual-fuel combustion turbines	149	1981
Whitehorn Units 2 & 3	Dual-fuel combustion turbines	149	1981
Fredonia Units 3 & 4	Dual-fuel combustion turbines	107	2001
Ferndale	Natural gas co-generation	253	1994; acquired 2012
Encogen	Natural gas co-generation	165	1993; acquired 1999
Sumas	Natural gas co-generation	127	1993; acquired 2008
Upper Baker River [2]	Hydroelectric	91	1959
Lower Baker River [2]	Hydroelectric	79	1925; reconstructed 1960; upgraded 2001
Snoqualmie Falls [3]	Hydroelectric	—	1898 to 1911 & 1957; currently no output due to rebuild
Electron [4]	Hydroelectric	22	1904 to 1929
Crystal Mountain	Internal combustion	3	1969
Total net capacity		3,513	

1 *Net Maximum Capacity is the capacity a unit can sustain over a specified period of time when not restricted by ambient conditions or deratings, less the losses associated with auxiliary loads.*

2 *The FERC jurisdictional facility was operated pursuant to 50-year license granted by the FERC in October 2008. The license provides protection and enhancements for fish and wildlife, water quality, recreation and cultural and historic resources.*

3 *The FERC jurisdictional facility was operated pursuant to 40-year license granted by the FERC in June 2004. Snoqualmie Falls will have partial output upon completion of powerhouse 2 anticipated for March 2013. The plant is expected to be fully operational and provide a net maximum capacity of approximately 54 MW upon completion of powerhouse 1 expected in the second quarter of 2013.*

4 *At December 31, 2012, Electron project output is limited to approximately 7 MW due to the condition of the flume that conveys water to the plant. This limitation is expected to continue into 2013.*

Columbia River Electric Energy Supply Contracts

During 2012, approximately 17.5% of PSE's energy requirement was obtained through long-term contracts with three Washington Public Utility Districts (PUDs) that own and operate hydroelectric projects on the Columbia River. PSE agrees to pay a share of the annual debt service, operating and maintenance costs and other expenses associated with each project in proportion to its share of projected output. PSE's payments are not contingent upon the projects being operable.

As of December 31, 2012, PSE was entitled to purchase portions of the power output of the PUDs' projects as set forth below:

Project	Contract Expiration Year	License Expiration Year	Company's Annual Purchasable Amount (Approximate) Percent of Output	Megawatt Capacity
Chelan County PUD:				
Rock Island Project [1]	2031	2029	25.0%	156
Rocky Reach Project	2031	2052	25.0%	325
Douglas County PUD: [2]				
Wells Project	2018	2052	29.9%	251
Grant County PUD: [3]				
Priest Rapids Development	2052	2052	0.8%	9
Wanapum Development	2052	2052	0.8%	9
Total				750

1 *PSE's previous contract for 50% of Rock Island output expired June 7, 2012. A new contract signed in 2006 for 25% of Rock Island output commenced July 1, 2012.*

2 *Douglas County PUD received a new 40-year FERC license for the Wells Project in November 2012.*

3 *PSE's share of power under the 2001 contract will decline over time as Grant County PUD's load increases. PSE's share of both the Priest Rapids and Wanapum developments was 0.9% at the end of 2012 and will not be less than 0.6% through 2052.*

Other Electric Supply, Exchange and Transmission Contracts and Agreements

PSE purchases electric energy under long-term firm purchased power contracts with other utilities and marketers in the Western region. PSE is generally not obligated to make payments under these contracts unless power is delivered. PSE has seasonal energy and capacity exchange agreements with the BPA (for 41 aMW of capacity) and with Pacific Gas & Electric Company (for 300 MW of capacity).

Further, PSE has entered into multiple various-term transmission contracts with other utilities 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.

Other transmission 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's load is available for sale to third parties. PSE also purchases short-term transmission services from a variety of providers, including the BPA.

In 2012, PSE had 4,417 MW and 596 MW of total transmission demand contracted with the BPA and other utilities, respectively. PSE's remaining transmission capacity needs are met via PSE owned transmission assets.

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 physical and financial fixed price derivative instruments to hedge the cost of natural gas. PSE utilizes natural gas storage capacity that is dedicated to and paid for by the power portfolio to facilitate increased natural gas supply reliability and intra-day dispatch of PSE's gas-fired generation resources. During 2012, approximately 93.0% of natural gas for power purchased by PSE for power customers originated in British Columbia and 7.0% originated in the United States.

Integrated Resource Plans, Resource Acquisition and Development

PSE is required by Washington Commission regulations to file electric and natural gas Integrated Resource Plans (IRP) every two years with the next IRP scheduled to be filed by May 30, 2013. As part of the resource acquisition process, PSE filed and conducted a Request-for-Proposal (RFP) process in 2011. The 2011 RFP updated the assumptions from the 2011 IRP and identified the following capacity needs:

	2013	2014	2015	2016
Projected MW shortfall	242	460	554	728

These expected shortfalls reflect the mix of energy efficiency programs deemed cost effective in the 2011 IRP. In response to the RFP, PSE received and evaluated 29 resource proposals. After the selection through the RFP process, PSE acquired the 270 MW Ferndale natural gas fuel power plant and executed a power purchase agreement with TransAlta Centralia for the purchase of up to 380 MW of coal transition power (the Centralia agreement).

PSE filed a petition for approval of the Centralia agreement and the recovery of related acquisition costs. On January 9, 2013, the Commission issued an order granting PSE's petition which contained conditions that have left PSE with a level of uncertainty such that it would terminate the contract. PSE subsequently filed for reconsideration of the order and the various stakeholders have until March 8, 2013 to respond to the PSE's petition. The Commission has indicated it will rule on PSE's petition by March 29, 2013.

Providing PSE's petition for reconsideration is approved, as a result of the proposed Centralia agreement and the addition of the Ferndale plant, PSE expects to have sufficient resources to meet its capacity needs over the next few years.

NATURAL GAS UTILITY OPERATING STATISTICS

	Year Ended December 31,		
	2012	2011	2010
Gas operating revenue by classes (dollars in thousands):			
Residential	$ 712,805	$ 760,442	$ 648,649
Commercial firm	277,232	303,267	262,735
Industrial firm	29,302	32,222	28,939
Interruptible	37,861	43,704	42,413
Total retail gas sales	1,057,200	1,139,635	982,736
Transportation services	15,434	15,017	14,082
Other	13,461	14,198	14,713
Total gas operating revenue	$ 1,086,095	$ 1,168,850	$ 1,011,531
Number of customers served (average):			
Residential	706,965	700,039	694,086
Commercial firm	53,728	53,676	53,703
Industrial firm	2,431	2,465	2,489
Interruptible	337	356	381
Transportation	194	175	152
Total customers	763,655	756,711	750,811
Gas volumes, therms (thousands):			
Residential	569,308	597,471	519,527
Commercial firm	253,743	270,300	239,693
Industrial firm	29,371	32,346	29,812
Interruptible	51,112	54,163	52,771
Total retail gas volumes, therms	903,534	954,280	841,803
Transportation volumes	225,810	224,330	205,516
Total volumes	1,129,344	1,178,610	1,047,319
Working gas volumes in storage at year end, therms (thousands):			
Jackson Prairie	77,968	85,506	70,213
Clay Basin	85,356	89,123	86,891
Average therms used per customer:			
Residential	805	853	749
Commercial firm	4,723	5,036	4,463
Industrial firm	12,082	13,122	11,978
Interruptible	151,668	152,143	138,507
Transportation	1,163,968	1,281,884	1,352,079
Average revenue per customer:			
Residential	$ 1,008	$ 1,086	$ 935
Commercial firm	5,160	5,650	4,892
Industrial firm	12,053	13,072	11,627
Interruptible	112,348	122,763	111,320
Transportation	79,559	85,810	92,645
Average revenue per therm sold:			
Residential	$ 1.252	$ 1.273	$ 1.249
Commercial firm	1.093	1.122	1.096
Industrial firm	0.998	0.996	0.971
Interruptible	0.741	0.807	0.804
Average retail revenue per therm sold	1.170	1.194	1.167
Transportation	0.068	0.067	0.069
Heating degree days	4,741	5,146	4,549
Percent of normal - NOAA 30-year average	100.5%	107.3%	94.8%

NATURAL GAS SUPPLY FOR NATURAL GAS CUSTOMERS

PSE 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 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. Accordingly, delivery of natural gas supply to PSE's natural gas system is dependent upon the reliable operations of NWP.

	At December 31,			
	2012		2011	
Peak Firm Natural Gas Supply [1]	Dth per Day	%	Dth per Day	%
Purchased gas supply:				
British Columbia	200,000	23.5%	190,000	21.9
Alberta	75,000	8.8%	70,000	8.0
United States	105,000	12.4%	120,000	13.8
Total purchased natural gas supply	380,000	44.7%	380,000	43.7%
Purchased storage capacity:				
Jackson Prairie	48,400	5.7%	58,000	6.7
Plymouth liquefied natural gas	70,500	8.3%	70,500	8.1
Total purchased storage capacity	118,900	14.0%	128,500	14.8%
Owned storage capacity:				
Jackson Prairie	348,700	41.0%	348,700	40.1
Propane and LNG	2,500	0.3%	12,500	1.4
Total owned storage capacity	351,200	41.3%	361,200	41.5%
Total peak firm natural gas supply	850,100	100.0%	869,700	100.0%
Other and commitments with third parties	(5,300)		(14,400)	
Total net peak firm natural gas supply	844,800		855,300	

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

For baseload, peak management and supply reliability purposes, PSE supplements its firm natural gas supply portfolio by purchasing natural gas in off-peak periods, injecting it into underground storage facilities and withdrawing it during the peak winter heating season. Underground storage facilities at Jackson Prairie in western Washington and at Clay Basin in Utah are used for this purpose. Clay Basin withdrawals are used to supplement purchases from the U.S. Rocky Mountain supply region, while Jackson Prairie provides incremental peak-day resources utilizing firm storage redelivery transportation capacity. 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) storage facility near Plymouth, Washington; using PSE-owned natural gas held in PSE's LNG peaking facility located within its distribution system in Gig Harbor, Washington; and 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 and capacity to meet anticipated growth in the requirements of its firm customers for the foreseeable future.

During 2012, approximately 51.0% of natural gas supplies purchased by PSE for its gas customers originated in British Columbia, while 20.0% originated in Alberta and 29.0% originated in the United States. PSE's firm natural gas supply portfolio has adequate flexibility in its transportation arrangements to enable it to achieve savings when there are regional price differentials between natural gas supply basins. The geographic mix of suppliers and daily, monthly and annual take requirements permit some degree of flexibility in managing natural gas supplies during off-peak periods to minimize costs. Natural gas is marketed outside PSE's service territory (off-system sales) whenever on-system customer demand requirements permit and the resulting economics of these transactions are reflected in PSE's natural gas customer tariff rates through the PGA mechanism.

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. The Jackson Prairie facility is operated and one-third owned by PSE. The facility 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 in excess of 453,000 Dekatherm (Dth) per day, which, after reduction for a portion temporarily released to the power portfolio and to a third party represents nearly 46.7% of PSE's expected near-term peak-day requirement. PSE's total firm storage capacity of the facility is approximately 9.8 million Dth. 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 natural gas requirements. The owned storage capacity at Jackson Prairie is now 8.5 million Dth.

Due to the recent expansion of Jackson Prairie storage withdrawal capacity and storage capacity, PSE's natural gas storage resources are expected to exceed natural gas customer requirements for the next few years. Therefore, through 2014, 50,000 Dth per day of natural gas storage withdrawal capacity and 500,000 Dth of natural gas storage capacity have been temporarily released at market rates to PSE's power portfolio, increasing natural gas supply reliability and facilitating intra-day dispatch of PSE's natural gas-fired generation resources. In addition, PSE has permanently released 3,500 Dth per day and temporarily released approximately 6,000 Dth per day of Jackson Prairie Storage firm withdrawal capacity (and associated storage capacity) in exchange for permanent and temporary firm pipeline capacity on a constrained portion of NWP's system.

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 provides system reliability. PSE holds over 12.8 million Dth of Clay Basin storage capacity and approximately 107,000 Dth per day of firm withdrawal capacity under two long-term contracts with remaining terms of five and seven years. PSE's maximum firm withdrawal capacity and total storage capacity at Clay Basin, net of releases, is over 74,000 Dth per day and exceeds 8.8 million Dth, respectively.

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 a last resort supply source 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. PSE owns and operates the Swarr vaporized propane-air station located in Renton, Washington which includes storage capacity for approximately 1.5 million gallons of propane. This propane-air injection facility is designed to deliver the equivalent of 10,000 Dth of natural gas per day for up to 12 days directly into PSE's distribution system, but is not currently in use, awaiting further reliability and safety upgrade. PSE owns and operates an LNG peaking facility in Gig Harbor, Washington, with total capacity of 10,600 Dth, which is capable of delivering the equivalent of 2,500 Dth of natural gas per day.

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 Spectra's Westcoast Energy (Westcoast). GTN, NOVA, and Foothills are all TransCanada companies. 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 approximately 523,000 Dth per day of capacity for its natural gas customers on NWP that provides firm year-round delivery to PSE's service territory. In addition, PSE holds approximately 520,000 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 supply electric generating facilities with approximately 168,000 Dth per day. PSE participates in the pipeline capacity release market to achieve savings for PSE's customers and has released certain segments of temporarily surplus firm capacity to third parties. PSE's firm transportation capacity contracts with NWP have remaining terms ranging from one to 32 years. However, PSE has either the unilateral right to extend the contracts under the contracts' current terms or the right of first refusal to extend such contracts under current FERC rules.

PSE's firm transportation capacity for its natural gas customers on Westcoast's pipeline is approximately 130,000 Dth per day under various contracts, with remaining terms of two to six years. PSE has other firm transportation capacity on Westcoast's pipeline, which supplies the electric generating facilities, totaling approximately 106,000 Dth per day, with remaining terms of two to six years. PSE has firm transportation capacity on NOVA and Foothills pipelines, totaling approximately 80,000 Dth per day, with remaining terms of two to eleven years. PSE has annual renewal rights on this capacity. PSE's firm transportation capacity on the GTN pipeline, totaling approximately 90,000 Dth per day, has a remaining term of 11 years.

Capacity Release

The 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. The FERC allows capacity to be released through several methods including open bidding and pre-arrangement. PSE has acquired some 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 natural gas customer portfolio are passed on to PSE's natural gas customers through the PGA mechanism.

ENERGY EFFICIENCY

PSE is required under Washington state law to pursue feasible, achievable cost-effective electric conservation. 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. PSE recovers the actual costs of electric and natural gas energy efficiency programs through a tracker or rider mechanism, as applicable, (for natural gas) and a rider mechanism (for electric). However, the tracker and rider mechanisms do not provide for any cost recovery of lost sales margin associated with reduced energy sales. To address this issue, PSE has proposed a decoupling mechanism in an accounting petition that is currently before the Washington Commission.

PSE's rates are designed to capture most of the approved revenue requirements for fixed costs through volumetric rates. PSE fully recovers these costs only if its customers consume a certain level of natural gas and electricity. This level of consumption is typically established in the utility's most recently completed rate case based upon historical natural gas and electric volumes. When customers use less natural gas or electricity, whether due to conservation, weather or economic conditions, PSE's financial performance is negatively impacted because recovery of fixed costs is reduced in proportion to the reduction in natural gas or electric sales.

Since May 1997, PSE has recovered direct electric energy efficiency (or conservation) expenditures through a rider mechanism. The rider mechanism allows PSE to defer the efficiency expenditures and amortize them to expense as PSE collects the efficiency expenditures in rates over a one-year period. As a result of the rider mechanism, direct electric energy efficiency expenditures are recovered. PSE does not earn a return on unamortized balances.

For gas conservation expenditures through 2011, PSE was authorized by the Washington Commission to defer natural gas energy efficiency (or conservation) expenditures and recover them through a tracker mechanism. The tracker mechanism allowed PSE to defer efficiency expenditures and recover them in rates over the subsequent year. The tracker mechanism also allowed PSE to recover an allowance for funds used to conserve energy on any outstanding balance that was not currently being recovered in rates. Beginning with 2012 gas conservation expenditures, PSE has been authorized by the Washington Commission to recover its direct natural gas energy efficiency (or conservation) expenditures through a rider mechanism similar to the electric rider mechanism. The rider mechanism allows PSE to defer the efficiency expenditures and amortize them to expense as PSE collects the efficiency expenditures over a one-year period. As a result of the rider mechanism, direct natural gas energy efficiency expenditures are recovered. As a result of converting to a rider mechanism, PSE no longer earns a return on unamortized balances.

ENVIRONMENT

PSE's operations, including generation, transmission, distribution, service and storage facilities, are subject to environmental laws and regulations by federal, state and local authorities. The primary areas of environmental law that have the potential to most significantly impact PSE's operations and costs include:

Air and Climate Change Protection

PSE owns numerous thermal generation facilities, including natural gas plants and an ownership percentage of a coal plant in Colstrip, Montana. All these facilities are governed by the Clean Air Act (CAA) and all have CAA Title V operation permits that must be renewed every five years. These facilities also emit greenhouse gases (GHGs), and thus are also subject to any current or future GHG or climate change legislation or regulation. Colstrip represents PSE's most significant source of GHG emissions.

Species Protection

PSE owns hydroelectric plants, wind farms and numerous miles of above ground electric distribution and transmission lines which can be impacted by laws related to species protection. A number of species of fish have been listed as threatened or endangered under the Endangered Species Act (ESA), which influences hydroelectric operations, and may affect PSE operations, potentially representing cost exposure and operational constraints. Similarly, there are a number of avian and terrestrial species that have been listed as threatened or endangered under the ESA or are protected by the Migratory Bird Act. Designations of protected species under these two laws have the potential to influence operation of our wind farms and above ground transmission and distribution systems.

Remediation of Contamination

PSE and its predecessors are responsible for environmental remediation at various contaminated sites. These include properties currently and formerly owned by PSE, as well as third party owned properties in which hazardous substances were generated or released. The primary cleanup laws PSE is subject to include the Comprehensive Environmental Response, Compensation and Liability Act (federal) and the Model Toxics Control Act (state). These laws may hold liable any current or past owner, or operator of a contaminated site, as well as, any generator, arranger, or disposer of regulated substances.

Hazardous and Solid Waste and PCB Handling and Disposal

Related to certain operations, including power generation and transmission and distribution maintenance, PSE must handle and dispose of certain hazardous and solid wastes, as well as, Polychlorinated Biphenyls (PCB) contaminated wastes. These actions are regulated by the Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act (federal), the Toxic Substances Control Act (federal), and the dangerous waste regulations (state) that impose complex requirements on handling and disposing of regulated substances.

Water Protection

PSE facilities that discharge wastewater or storm water, or store bulk petroleum products are governed by the Clean Water Act (federal and state) which includes the Oil Pollution Act amendments. This includes most generation facilities (and all those with water discharges and some with bulk fuel storage), and many other facilities and construction projects depending on drainage, facility or construction activities, and chemical, petroleum and material storage.

Siting New Facilities

In siting new generation, transmission, distribution or other related facilities, PSE is subject to the State Environmental Policy Act, and may be subject to the federal National Environmental Policy Act, if there is a federal nexus, as well as, other local siting and zoning ordinances. These requirements may potentially require mitigation of environmental impacts to the fullest extent possible as well as other measures that can add significant cost to new facilities.

RECENT AND FUTURE ENVIRONMENTAL LAW AND REGULATION

Recent and future environmental law and regulations may be imposed at a federal, state or local level and may have a significant impact on cost of PSE operations. PSE monitors legislative and regulatory developments for environmental issues with the potential to alter the operation and cost of our generation plants, transmission and distribution system, and other assets. Recent, pending and potential future environmental law and regulations with the most significant potential impacts to PSE's operations and costs are described below.

Climate Change and Greenhouse Gas Emissions

PSE recognizes the growing concern that increased atmospheric concentrations of GHG contribute to climate change. PSE believes that climate change is an important issue that requires careful analysis and considered responses. A climate policy continues to evolve at the state and federal levels and PSE remains involved in state, regional and federal policymaking activities. PSE will continue to monitor the development of any climate change or climate change related air emission reduction initiative at the state and western regional level. PSE will also consider the known impact of any future legislation or new government regulation on the cost of generation in its IRP process.

The Tailoring Rule, which became effective January 2, 2011, sets permit levels for GHG emissions in two phases for power plants and other large stationary sources. The ruling limits the amount of GHG emissions a facility can emit by requiring installment of Best Available Control Technology (BACT). Phase I requires existing facilities that emit more than 100,000 tons of emissions per year to comply with the new BACT rules when air permits are renewed or when major modifications are made after January 2011. Phase II, which begins after July 2011, requires preconstruction permits using BACT for new projects that emit 100,000 tons of emissions per year or existing projects that make major modifications and that emit more than 75,000 tons per year. Currently the EPA has only released BACT guidance for coal technology. The Environmental Protection Agency (EPA) work to determine natural gas turbine BACT guidance is ongoing. Potential impacts on Colstrip are being evaluated and impacts to our gas fleet cannot yet be determined.

On March 27, 2012 EPA proposed a New Source Performance Standard (NSPS) to limit carbon dioxide from new fossil fuel-fired electric generation units. The proposed standard would only apply to new generating units. The EPA did not propose standards for existing fossil fuel power plants, nor did it indicate a timeline for proposing these in the future. The proposed output-based standard for new units is 1,000 pounds of carbon dioxide per megawatt-hour (MWh).

Each year, PSE is required to submit, on an annual basis, a report of its GHG emissions to the State of Washington including a report of emissions from all individual power plants emitting over 10,000 tons per year of GHGs and from certain natural gas distribution operations. Emissions exceeding 25,000 tons per year of GHGs from these sources must also be reported to the EPA. Capital investments to monitor GHGs from the power plants and in the distribution system are not required at this time. Since 2002, PSE has voluntarily undertaken an annual inventory of its GHG emissions associated with PSE's total electric retail load served from a supply portfolio of owned and purchased resources. The most recent data indicate that PSE's total GHG emissions (direct and indirect) from its electric supply portfolio in 2011 were 10.4 million tons of carbon dioxide equivalent. Approximately 43.0% of PSE's total GHG emissions (approximately 4.5 million tons) are associated with PSE's ownership and contractual interests in Colstrip.

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

Mercury Emissions

Mercury control equipment has been installed at Colstrip and has operated at a level that meets the current Montana requirement. Compliance based on a rolling 12-month average was first confirmed in January 2011 and has continued to meet the requirement.

EPA published the final Mercury and Air Toxics Standard (MATS rule) in February 2012. The MATS rule establishes numerical emissions limitations at coal-fired power plants for mercury (1.2 lb/TBtu), acid gases, certain toxic metals using a particulate matter surrogate (0.03 lb/MMBtu), sulfur dioxide, and nitrogen oxides. Generating units have 3 years, until April 2015, to comply with MATS and could receive up to a 1-year extension from permitting authorities if necessary for the installation of controls. Colstrip currently meets the MATS limits for mercury and acid gases and is conducting testing to determine what is needed to allow compliance with particulate surrogate for other metals. PSE cannot determine the outcome at this time.

Additional Colstrip Emission Controls

On June 15, 2005, the EPA issued the Clean Air Visibility rule to address regional haze or regionally-impaired visibility caused by multiple sources over a wide area. The rule defines Best Available Retrofit Technology (BART) requirements for electric generating units, including presumptive limits for sulfur dioxide, particulate matter and nitrogen oxide controls for large units. The final Regional Haze/BART FIP came out in September 2012. There are no requirements for Units 3&4, but Units 1&2 will need upgrading pollution controls to meet new sulfure dioxide and nitrogen oxide limits. Sierra Club filed an appeal of the FIP on November 15, 2012. PPL filed an appeal on behalf of the plant on November 16, 2012. PSE cannot yet determine the outcome of this litigation.

Coal Combustion Residuals

On June 21, 2010, the EPA issued a proposed rulemaking for the "Identification and Listing of Special Wastes: Disposal of Coal Combustion Residuals (CCR) from Electric Utilities" which proposes different regulatory mechanisms to regulate coal ash. The EPA received over 450,000 comments and over 2 million pages on the respective proposals in November 2010, including comments from PSE and other Colstrip owners. EPA does not have a schedule for issuing a final CCR regulation.

EPA proposed three alternative regulations. Under the first two options, coal ash could be regulated as a solid waste under Subtitle D provisions of the Resource Conservation and Recovery Act (RCRA). This would give authority to the states to oversee a set of performance standards for handling and disposal. Coal ash would be listed as non-hazardous and would allow wet handling to continue, and it would allow continued use of surface impoundments provided they are equipped with protective liners. One of these two options would require significantly less modifications to closed as well as in-use impoundments.

Under the third option, coal ash could be regulated as a hazardous waste under Subtitle C provisions of the RCRA, which would make coal ash subject to a comprehensive program of federally enforceable requirements for waste management and disposal. Regulation under Subtitle C would essentially require the phase-out of wet handling and surface impoundments. The EPA estimates over 500 surface impoundments would be affected by this ruling.

The impact to Colstrip operations and to PSE, could range from minimal to significant. Due to the wide range in the options proposed by the EPA, PSE cannot determine the potential impacts with any more certainty at this time. We are involved with monitoring development of the final rule and are advocating for a reasonable approach that would be both protective of the environment and cost-effective.

PCBs

On April 7, 2010, the EPA issued an Advance Notice of Proposed Rule Making (ANPRM) soliciting information on a broad range of questions concerning inventory, management, use, and disposal of PCB-containing equipment. The EPA is using this ANPRM to seek data to better evaluate whether to initiate a rulemaking process geared toward a mandatory phase-out of all PCBs. This would likely remove all existing use authorizations for PCBs in electrical and gas pipeline equipment. As proposed, the ANPRM would mandate a phase out of in-service PCBs through a phased process with full removal achieved by 2025.

The end of the comment period for the ANPRM was initially July 6, 2010 but due to the volume of comments received, EPA has rescheduled the issuance to April 2013. At this time, PSE cannot determine what the impacts of this NPRM will have on its operations but will continue to work closely with USWAG and AGA to monitor developments and advocate for a reasonable approach that would be protective of the environment and cost-effective.

EXECUTIVE OFFICERS OF THE REGISTRANTS

The executive officers of Puget Energy as of March 4, 2013 are listed below along with their business experience during the past five years. Officers of Puget Energy are elected for one-year terms.

Name	Age	Offices
K. J. Harris	48	President and Chief Executive Officer since March 1, 2011; President July 2010 – February 2011; Executive Vice President and Chief Resource Officer 2007 – 2010; Senior Vice President Regulatory Policy and Energy Efficiency 2005 – 2007.
D. A. Doyle	54	Senior Vice President and Chief Financial Officer since November 2011. Prior to PSE, he was President of Wisconsin Sports Development Corporation 2010 – November 2011; Vice President and Chief Financial Officer of American Transmission Company, LLC 2000 – 2009.
D. E. Gaines	56	Vice President Finance and Treasurer since March 2002.
S. R. Secrist	51	Vice President, General Counsel and Chief Ethics and Compliance Officer since January 2011; Interim General Counsel October 2010 – January 2011; Deputy General Counsel 2006 – October 2010.
M. J. Stranik	49	Controller and Principal Accounting Officer since June 2012; Assistant Controller - Financial Reporting March 2011 – June 2012; Assistant Controller from November 2002 – March 2011.

The executive officers of PSE as of March 4, 2013 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
K. J. Harris	48	President and Chief Executive Officer since March 1, 2011; President July 2010 – February 2011; Executive Vice President and Chief Resource Officer 2007 – 2010; Senior Vice President Regulatory Policy and Energy Efficiency 2005 – 2007.
D. A. Doyle	54	Senior Vice President and Chief Financial Officer since November 2011. Prior to PSE, he was President of Wisconsin Sports Development Corporation 2010 – November 2011; Vice President and Chief Financial Officer of American Transmission Company, LLC 2000 – 2009.
P. K. Bussey	56	Senior Vice President and Chief Customer Officer since March 2012. Prior to PSE, he was President and Chief Executive Officer of Seattle Metropolitan Chamber May 2009 - March 2012. Senior Vice President Corporate Affairs of PSE September 2003 - May 2009.
D. E. Gaines	56	Vice President Finance and Treasurer since March 2002.
S. McLain	56	Senior Vice President Delivery Operations since February 2011; Senior Vice President Operations 2003 – January 2011.
M. D. Mellies	52	Senior Vice President and Chief Administrative Officer since February 2011; Vice President Human Resources 2005 – January 2011.
S. R. Secrist	51	Vice President, General Counsel and Chief Ethics and Compliance Officer since January 2011; Interim General Counsel October 2010 – January 2011; Deputy General Counsel 2006 – October 2010.
M. J. Stranik	49	Controller and Principal Accounting Officer since June 2012; Assistant Controller - Financial Reporting March 2011 – June 2012; Assistant Controller from November 2002 – March 2011.
P. M. Wiegand	60	Senior Vice President Energy Operations since February 2011; Senior Vice President Power Generation 2010 – January 2011; Vice President Power Generation 2007 – 2010; Vice President Project Development & Contract Management 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 PSE's 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 the 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 the FERC with respect to the transmission of electric energy, the sale of electric energy at the wholesale level, 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 normalized assumptions about rate year power costs, weather and hydrological conditions. 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, revenue 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 the aforementioned 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 hydrological 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 owned and controlled power resources in the near future. 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 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 thus reducing 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:

- 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 on a substantial portion of distribution infrastructure.

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, hydroelectric, 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;
- 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 or safety related stoppages;
- Terrorist attacks; and
- Catastrophic events such as fires, explosions, floods or acts of nature.

If PSE is unable to protect our information technology infrastructure and network against data corruption, cyber-based attacks or network security breaches, our operations could be disrupted.

PSE operates in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure. Despite our implementation of security measures, our technology systems may be vulnerable to disability, failures or unauthorized access due to hacking, viruses, acts of war or terrorism and other causes. If our technology systems were to fail or be breached and we were unable to recover in a timely manner, we may be unable to fulfill critical business functions and sensitive, confidential and other data could be compromised, which could have a material adverse effect on our results of operations, financial condition and cash flows. In addition, these cyber-based attacks could disrupt our ability to produce or distribute some portion of our energy products and could affect the reliability or operability of the electric and natural gas systems.

PSE is subject to the commodity price, delivery and credit risks associated with the energy markets as well as to supply and price risks affecting PSE's construction and maintenance programs.

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.

Further, as a consequence of its electric generation construction and reconstruction programs and investments in its electric and gas distribution systems, PSE contracts to purchase substantial quantities of steel, cable, and similar materials, and thus is subject to supply and price risks affecting these items. 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.

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, including air and climate protection, endangered species protection, remediation of contamination, waste handling and disposal, water protection and siting new facilities. To comply with these legal requirements, PSE must spend significant sums of money on measures including resource planning, remediation, monitoring, analysis, mitigation measures, pollution control equipment and emissions related abatement and fees. New environmental 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. Compliance with these or other future regulations could require significant 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. PSE cannot yet determine the costs of compliance with the recently enacted legislation. Recent decisions related to climate change by the United States Supreme Court and the EPA, together with efforts by Congress, have drawn greater attention to this issue at the federal, state and local level. While PSE cannot yet determine costs associated with these or future decisions or potential future legislation, there may be a significant impact on the cost of carbon-intensive coal generation, in particular.

PSE'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 revenue, 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 revenue is recognized in the first and fourth quarters related to the heating season. However, 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 revenue 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.

PSE may be adversely affected by extreme events in which PSE is not able to promptly respond and repair the electric and gas infrastructure system.

PSE must maintain an emergency planning and training program to allow PSE to quickly respond to extreme events. Without emergency planning, PSE 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 or ineffective response to extreme events may have an adverse effect on earnings as customers may be without electricity and natural gas for an extended period of time.

PSE may be negatively affected by its inability to attract and retain professional and technical employees.

PSE's ability to implement a workforce succession plan is dependent upon PSE's ability to employ and retain skilled professional and technical workers. Without a skilled workforce, PSE's ability to provide quality service to PSE's customers and to meet regulatory requirements could affect PSE's earnings.

PSE depends on an aging work force and third party vendors to perform certain important services.

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

Poor performance of pension and postretirement benefit plan investments and other factors impacting plan costs could unfavorably impact PSE's cash flow 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 the current interest rate environment and therefore, continued adverse market performance or low interest rates could result in lower rates of return for the investments that fund PSE's pension and postretirement benefits plans and could increase PSE's funding requirements related to the pension plans. Any contributions to PSE's plans in 2013 and beyond as well as the timing of the recovery of such contributions in general rate cases could impact PSE's cash flow and liquidity.

PSE may be adversely affected by its inability to successfully implement certain technology projects.

PSE is currently undertaking a multi-year company-wide business process modernization effort which will replace existing software PSE currently uses for processing customer records and billing, mapping infrastructure assets and handling outage management tasks. These projects, are expected to be fully deployed by 2013, include: (1) a new Customer Information System intended to replace a PSE application that manages customer information and tracks outages and (2) an Outage Management System expected to augment and improve PSE's ability to pinpoint the sources of electric system outages and respond to them more quickly, focus repair efforts and more accurately predict restoration times. Implementation of these information systems is complex, expensive and time consuming. If PSE does not successfully implement the new systems and new processes, or if the systems do not operate as intended, it could result in substantial disruptions to PSE's business, which could have a material adverse effect on our results of operations and financial condition.

Potential municipalization or technological developments may adversely affect PSE's financial condition.

PSE may be adversely affected if we experience a loss in the number of our customers due to municipalization or other related government action. When a town or city establishes its own municipal-owned utility, it acquires our assets and takes over the delivery of energy services that we provide. This loss of customers and related revenue could negatively affect PSE's financial condition. In addition, there is also the risk that advances in power generation, energy efficiency and other alternative energy technologies, such as solar generation, could lead to more wide-spread use of these technologies, thereby reducing customer demand for the energy supplied by PSE. This reduction in usage and demand would reduce PSE's revenue and negatively impact our financial condition.

RISKS RELATING TO PUGET ENERGY AND PSE OPERATIONS

The Company's business is dependent on its ability to successfully access capital.

The Company relies on access to internally generated funds, bank borrowings through multi-year committed credit facilities and short-term money markets as sources of liquidity and longer-term debt markets to fund PSE's utility construction program and other capital expenditure requirements of PSE. If Puget Energy or PSE are unable to access capital on reasonable terms, their 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, a downgrade of Puget Energy's or PSE's credit rating or the imposition of restrictions on borrowings under their credit facilities in the event of a deterioration of financial ratios, may increase Puget Energy's and PSE's cost of borrowing or adversely affect the ability to access one or more financial markets.

The amount of the Company's debt could adversely affect its liquidity and results of operations.

Puget Energy and PSE have short-term and long-term debt, and may incur additional debt (including secured debt) in the future. Puget Energy has access to a multi-year $1.0 billion revolving credit facility, secured by substantially all of its assets, of which $434.0 million was outstanding as of December 31, 2012. PSE has access to three unsecured credit facilities that provide, in the aggregate $1.15 billion in short-term borrowing capability. PSE refinanced its credit facilities in February 2013 to two facilities with $1.0 billion in short-term borrowing capability, a 5 year contract, lower commitment fee rate and less restrictive covenants. In conjunction with the new PSE agreement, the Puget Energy agreement was reduced to a total of $800 million. In addition, Puget Energy has issued $1.4 billion in senior secured notes, whereas PSE, as of December 31, 2012 had approximately $3.8 billion outstanding under first mortgage bonds, pollution control bonds, senior notes and junior subordinated notes. The Company's debt level could have important effects on the business, including but not limited to:

- making it difficult to satisfy obligations under the debt agreements and increasing the risk of default on the debt obligations;

- making it difficult to fund non-debt service related operations of the business; and
- limit the Company's financial flexibility, including its ability to borrow additional funds on favorable terms or at all.

A downgrade in Puget Energy's or PSE's credit rating could negatively affect the ability to access capital and the ability to hedge in wholesale markets.

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 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 facilities, the borrowing spreads over the London Interbank Offered Rate (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 corporate credit rating could cause counterparties in the wholesale electric, wholesale natural gas and financial derivative markets to request 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 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 IRS 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.

Potential legislation and regulatory actions could increase the Company's costs, reduce the Company's revenue and cash flow, or otherwise alter the way the Company conducts business.

In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank) was signed into law. Title VII of the Dodd-Frank law gave regulators including the Commodities Futures Trading Commission (CFTC) and the Securities Exchange Commission the authority to create new oversight structures for derivative financial instruments, which were widely thought to have contributed to the 2008 financial crisis. The new legislation of certain over-the-counter swaps could expand collateral requirements of swaps, which may make it more costly for companies and/or limit the Company's ability to enter into such transactions. The Dodd-Frank amended section 2(h)(7) of the Commodities Exchange Act to provide an elective exemption from the clearing requirements of Title VII of the Dodd-Frank Act for any entity that is not a financial entity, is using swaps to hedge or mitigate commercial risk, and notifies the CFTC, in a manner set forth by the CFTC, how it generally meets its financial obligations associated with entering into non-cleared swaps. The Company is evaluating the legislation and the CFTC's implementation of it to determine its impact, if any, on the Company's hedging program, results of operations and liquidity. The Company will not know the full impact of the new legislation until the regulations are finalized.

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 PSE's 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 PSE's electric and natural gas mortgage indentures. In addition, beginning February 6, 2009, pursuant to the terms of the Washington Commission merger order, PSE may not declare or pay dividends if PSE's common equity ratio, calculated on a regulatory basis, is 44.0% or below except to the extent a lower equity ratio is ordered by the Washington Commission. Also, pursuant to the merger order, PSE may not declare or make any distribution, unless on the date of distribution PSE's corporate credit/issuer rating is investment grade, or if its credit ratings are below investment grade, PSE's ratio of Earnings Before Interest, Tax, Depreciation and Amortization (EBITDA) to interest expense for the four most recently ended fiscal quarters prior to such date is equal to or greater than three to one. The common equity ratio, calculated on a regulatory basis, was 48.0% at December 31, 2012 and the EBITDA to interest expense was 4.5 to 1.0 for the 12 months then ended.

PSE's ability to pay dividends is also limited by the terms of its credit facilities, pursuant to which PSE is not permitted to pay dividends during any Event of Default, or if the payment of dividends would result in an Event of Default (as defined in the facilities), such as failure to comply with certain financial covenants.

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. The Company's corporate headquarters is housed in a leased building located in Bellevue, Washington.

ITEM 3. LEGAL PROCEEDINGS

From time to time, the Company is involved in litigation relating to claims arising out of its operations in the normal course of business. The following is a description of legal proceedings that are material to PSE's operations:

Residential Exchange. The Northwest Power Act, through the Residential Exchange Program (REP), provides access to the benefits of low-cost federal power for residential and small farm customers of regional utilities, including PSE. The program is administered by the the BPA. Pursuant to agreements (including settlement agreements) between the BPA and PSE, the BPA has provided payments of REP benefits to PSE, which PSE has passed through to its residential and small farm customers in the form of electricity bill credits.

In 2007, the United States Court of Appeals for the Ninth Circuit (Ninth Circuit) ruled that REP agreements of the BPA with PSE and a number of other investor-owned utilities were inconsistent with the Northwest Power Act. Since that time, those investor-owned utilities, including PSE, the BPA and other parties have been involved in ongoing litigation at the Ninth Circuit relating to the amount of REP benefits paid to utilities, including PSE, for the fiscal year 2002 through fiscal year 2011 period and the amount of REP benefits to be paid going forward.

In July 2011, the BPA, PSE and a number of other parties entered into a settlement agreement that by its terms if upheld in its entirety would resolve the disputes between BPA and PSE regarding REP benefits paid for fiscal years 2002-2011 and determine REP benefits for fiscal years 2012-2028. In October 2011, certain other parties challenged BPA decisions with regard to its entering into this most recent settlement agreement. Oral arguments in the Ninth Circuit on this litigation occurred on February 19, 2013. Pending disposition of this challenge, the other pending Ninth Circuit litigation regarding REP benefits has been stayed by the Ninth Circuit.

Due to the pending and ongoing proceedings, PSE is unable to reasonably estimate any amounts of REP payments either to be recovered by the BPA or to be paid for any future periods to PSE, and is unable to determine the impact, if any, these proceedings and litigation may have on PSE. However, the Company believes it is unlikely that any unfavorable outcome would have a material adverse effect on PSE because REP benefits received by PSE are passed through to PSE's residential and small farm customers.

Notice of Intent to Sue. PSE has a 50% ownership interest in Colstrip Units 1 and 2, and a 25% interest in Colstrip Units 3 and 4. On July 25, 2012, Sierra Club and the Montana Environmental Information Center (MEIC) issued a Notice of Intent to Sue for violations of the Clean Air Act at Colstrip Steam Electric Station. The notice, which was amended on August 30, 2012, September 27, 2012, and December 1, 2012, was addressed to the owner or managing agent of Colstrip and to the other Colstrip co-owners, including PSE. The notices allege violations of the Clean Air Act and state that the Sierra Club and MEIC will request a United States District Court to impose injunctive relief and civil penalties, require a beneficial environmental project in the areas affected by the alleged air pollution and require reimbursement of Sierra Club's and MEIC's costs of litigation and attorney's fees. Under the Clean Air Act, lawsuits cannot be filed until 60 days after the applicable notice date. PSE is evaluating the allegations set forth in the notices and cannot at this time predict the outcome of this matter.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

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 LLC (Puget Equico), which is an indirect wholly-owned subsidiary of Puget Holdings, and are not publicly traded. 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.

The payment of dividends on PSE common stock to Puget Energy is restricted by provisions of certain covenants applicable to long-term debt contained in PSE’s mortgage indentures in addition to terms of the Washington Commission merger order. Puget Energy’s ability to pay dividends is also limited by the merger order issued by the Washington Commission as well as by the terms of its credit facilities. For further discussion, see Item 1A, Risk Factors, Risks Relating to Puget Energy’s Corporate Structure and Item 7, Management’s Discussion and Analysis of Financial Condition and Results of Operations included in this report.

From time to time, when deemed advisable and permitted, each of PSE and Puget Energy pay dividends on its common stock. During 2012, 2011 and 2010, each of PSE paid dividends to its parent, Puget Energy, and Puget Energy paid dividends to its parent, Puget Equico, in the amounts shown in Puget Energy's and PSE's Consolidated Statements of Common Shareholder's Equity included in this report.

ITEM 6. SELECTED FINANCIAL DATA

The following tables show selected financial data. This information should be read in conjunction with the Management Discussion and Analysis and the audited consolidated financial statements and the related notes, included in Items 7 and 8 of this report, respectively.

	Successor [1]				Predecessor [1]	
Puget Energy Summary of Operations	Year Ended December 31,			February 6, 2009 - December 31,	January 1, 2009 - February 5,	Year Ended December 31,
(Dollars in Thousands)	2012	2011	2010	2009	2009	2008
Operating revenue	$ 3,215,156	$ 3,318,765	$ 3,122,217	$ 2,925,148	$ 403,713	$ 3,357,773
Operating income	715,535	474,940	308,234	474,863	35,410	382,748
Income from continuing operations	273,821	123,290	30,311	174,015	12,756	154,929
Net income	273,821	123,290	30,311	174,015	12,756	154,929
Basic earnings per common share from continuing operations	N/A	N/A	N/A	N/A	N/A	1.20
Basic earnings per common share	N/A	N/A	N/A	N/A	N/A	1.20
Diluted earnings per common share from continuing operations	N/A	N/A	N/A	N/A	N/A	1.19
Diluted earnings per common share	N/A	N/A	N/A	N/A	N/A	1.19
Dividends per common share	N/A	N/A	N/A	N/A	N/A	$ 1.00
Book value per common share	N/A	N/A	N/A	N/A	N/A	17.53
Total assets at year end	$ 12,801,579	$ 12,407,306	$ 11,929,336	$ 11,900,140	$ 8,594,836	$ 8,434,102
Long-term debt	5,083,200	5,027,367	4,132,713	3,790,698	2,520,860	2,270,860
Preferred stock subject to mandatory redemption	—	—	—	—	—	1,889
Junior subordinated notes	250,000	250,000	250,000	250,000	250,000	250,000
Capital lease obligations	24,629	32,207	42,603	134,229	68,293	68,586

Puget Sound Energy Summary of Operations	Year Ended December 31,				
(Dollars in Thousands)	2012	2011	2010	2009	2008
Operating revenue	$ 3,216,259	$ 3,319,803	$ 3,122,217	$ 3,328,501	$ 3,357,773
Operating income	692,989	431,043	207,591	383,135	392,386
Net income	356,170	204,120	26,095	159,252	162,736
Total assets at year end	$ 10,594,276	$ 10,108,143	$ 9,310,784	$ 8,816,571	$ 8,435,855
Long-term debt	3,513,258	3,523,845	2,953,860	2,638,860	2,270,860
Preferred stock subject to mandatory redemption	—	—	—	—	1,889
Junior subordinated notes	250,000	250,000	250,000	250,000	250,000
Capital lease obligations	24,629	32,207	—	54,196	68,586

[1] *All of the operations of Puget Energy are conducted through its subsidiary PSE. "Predecessor" refers to the operations of Puget Energy and PSE prior to the consummation of the merger. "Successor" refers to the operations of Puget Energy and PSE subsequent to the merger. The merger was accounted for in accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 805.*

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 and PSE objectives, expectations and intentions. Words or phrases such as "anticipates," "believes," "continues," "could," "estimates," "expects," "future," "intends," "may," "might," "plans," "potential," "predicts," "projects," "should," "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 (SEC) 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 is an energy services holding company and all of its operations are conducted through its subsidiary PSE, a regulated electric and natural gas utility company. PSE is the largest electric and natural gas utility in the state of Washington, primarily engaged in the business of electric transmission, distribution and generation and natural gas distribution. Puget Energy's business strategy is to generate stable cash flows by offering reliable electric and natural gas service in a cost-effective manner through PSE. On February 6, 2009, Puget Holdings completed its merger with Puget Energy. Puget Holdings is a consortium of long-term infrastructure investors including Macquarie Infrastructure Partners I, Macquarie Infrastructure Partners II, Macquarie Capital Group Limited, FSS Infrastructure Trust, the Canada Pension Plan Investment Board (CPPIB), the British Columbia Investment Management Corporation, and the Alberta Investment Management Corporation. As a result of the merger, all of Puget Energy's common stock is indirectly owned by Puget Holdings. Puget Energy accounted for the merger as a business combination and all its assets and liabilities were recorded at fair value as of the merger date. PSE's basis of accounting continues to be on a historical basis and PSE's financial statements do not include any purchase accounting adjustments. Puget Energy and PSE are collectively referred to herein as "the Company."

PSE generates revenue and cash flow primarily from the sale of electric and natural gas services to residential and commercial customers within a service territory covering approximately 6,000 square miles, principally in the Puget Sound region of the state of Washington. To meet customer growth, to replace expiring power contracts and to meet Washington state's renewable energy portfolio standards, PSE is increasing energy efficiency programs to reduce the demand for additional energy generation and is pursuing additional renewable energy production resources (primarily wind) and base load natural gas-fired generation. The Company's external financing requirements principally reflect the cash needs of its construction program, its schedule of maturing debt and certain operational needs. PSE requires access to bank and capital markets to meet its financing needs.

The Company's strategy is to be a safe, dependable, and efficient utility. The Company has made a commitment to seek to be world-class in safety for employees, customers and communities; provide exceptional customer service; invest in technology to enhance customer service; commit to the professional development of the workforce; work with stakeholders to ensure timely and consistent regulatory support; and drive necessary changes to maintain the financial strength of the Company.

These investments and commitments related to utility infrastructure and customer service may give rise to expenditures, which may not be recovered timely through the ratemaking process. Additionally, Washington state law requires PSE to pursue conservation initiatives that promote efficient use of energy. This mandate negatively impacts financial performance due to the lost sales margins arising from reduced energy sales. To mitigate the "regulatory lag" and costs associated with conservation initiatives, the Company is focused on the following initiatives:

- Develop an Expedited Rate Filing (ERF) process that would reduce the time to recover costs.
- Establish a decoupling mechanism to allow recovery of lost margins from conservation initiatives.
- Design a pipeline integrity program that would accelerate and enhance the safety of the gas system and ultimately reduce costs.

Additionally, the Company has initiatives to reduce spending over the next five years to maintain its financial strength. The initiatives include re-engineering the customer value chain process as well as evaluating and improving processes in all areas of the Company.

For the year ended December 31, 2012 as compared to the prior year, PSE's net income was positively affected by the following two factors: (1) an unrealized gain in derivatives instruments for energy contracts compared to an unrealized loss for the same periods in the prior year; and (2) increased electric margins driven by lower power costs.

Further detail on each of these primary drivers, as well as other factors affecting performance, is set forth in this "Overview" section, as well as in other sections of the Management's Discussion & Analysis.

NON-GAAP FINANCIAL MEASURES

The following discussion includes financial information prepared in accordance with U.S. Generally Accepted Accounting Principles (GAAP), as well as return on equity excluding unrealized loss on derivative instruments (net income plus unrealized loss on derivative instruments divided by average common equity) that is considered a "non-GAAP financial measure." 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 return on equity excluding unrealized loss on derivative instruments is intended to supplement readers' understanding of the Company's operating performance. Return on equity excluding unrealized loss on derivative instrument is used by the Company to determine whether the Company is collecting the appropriate earnings from its customers to allow recovery of investor's capital. PSE's return on equity may not be comparable to other companies return on equity measures. Furthermore, this measure is not intended to replace return on equity (net income divided by average common equity) as determined in accordance with GAAP as an indicator of operating performance.

The Company has faced certain challenges which caused a significant reduction in the return on equity as compared to other years. The following table presents PSE's return on equity for 2012 and 2011:

	2012			2011		
(Dollars in Thousands)	Earnings	Average Common Equity	Return On Equity	Earnings	Average Common Equity	Return On Equity
Return on equity - GAAP	$ 356,170	$ 3,313,183	10.8%	$ 204,120	$ 3,098,564	6.6%
Less/Plus: Unrealized gains and losses on derivative instruments, after-tax	(77,428)	—	*	35,195	—	*
Less: Equity adjustments [1]	—	268,610	*	—	341,231	*
Plus: Impact of average of monthly average (AMA)	—	32,131	*	—	36,242	*
AMA regulated return on equity	$ 278,742	$ 3,613,924	7.7%	$ 239,315	$ 3,476,037	6.9%
Authorized regulated return on equity [2]			9.8%			10.1%

1 *Equity adjustments are related to removing the impacts of accumulated other comprehensive income (OCI), subsidiary retained earnings and retained earnings of derivative instruments.*

2 *The authorized regulated return on equity was approved by the Washington Commission in its general rate case order which became effective May 14, 2012 and April 8, 2010 for the years ended December 31, 2012 and December 31, 2011, respectively.*

* *Not meaningful*

The Company's 2012 return on equity, excluding derivative instruments, was 7.7%, which is lower than the authorized return on equity due to the following:

- Operating revenue was $124.2 million lower than the amount allowed in rates for the year ended December 31, 2012. However, margins increased $27.6 million due to significantly lower power costs.
- Utility operations and maintenance expense was $18.7 million higher than the amount allowed in rates for the year ended December 31, 2012. The increase was driven by an increase in costs in electric production, administration and general expenses and customer service expense.
- Depreciation expense was $38.2 million higher than the amount allowed in rates for the year ended December 31, 2012. The increase was primarily due to additional electric expenditures placed into service.
- Utility rate making process has a delay between incurring expenses and their recovery in rate base. PSE increased ratebase by $416.7 million since its last general rate increase effective May 14, 2012.

The Company's 2011 return on equity, excluding derivative instruments, was 6.9%, which is lower than the authorized return on equity due to the following:

- Utility operations and maintenance expense was $21 million higher than the amount allowed in rates for the year ended December 31, 2011. The increase was driven by an increase in costs in electric production, administration and general expenses and gas operations costs.
- Depreciation expense was $30 million higher than the amount allowed in rates for the year ended December 31, 2011. The increase was primarily due to additional electric and common utility capital expenditures placed into service.
- Utility rate making process has a delay between incurring expenses and their recovery in ratebase. PSE increased ratebase by $484 million since its last general rate increase effective April 8, 2010.
- These negative impacts were offset by favorable load which increased natural gas therm sales 7.0% for the year ended December 31, 2011, due to cooler temperatures in 2011 as compared to the same period in 2010. Also, favorable electric power costs had a positive impact on net income.

Factors and Trends Affecting PSE's Performance. PSE's regulatory requirements and operational needs require the investment of substantial capital in 2012 and future years. Because PSE intends to seek recovery of such investments through the regulatory process, its financial results depend heavily upon favorable outcomes from that process. Further, PSE's financial performance is heavily influenced by general economic conditions in its service territory, which affect customer growth and use-per-customer and thus utility sales, as well as by its customers' conservation investments, which also tend to reduce energy sales. The principal business, economic and other factors that affect PSE's operations and financial performance include:

- The rates PSE is allowed to charge for its services;
- PSE's ability to recover fixed costs that are included in rates which are based on volume;
- Weather conditions, including snow-pack affecting hydrological conditions;
- Demand for electricity and natural gas among customers in PSE's service territory;
- Regulatory decisions allowing PSE to recover costs, including purchased power and fuel costs, on a timely basis;
- PSE's ability to supply electricity and natural gas, either through company-owned generation, purchase power contracts or by procuring natural gas or electricity in wholesale markets;
- Availability and access to capital and the cost of capital;
- Regulatory compliance costs, including those related to new and developing federal regulations of electric system reliability, state regulations of natural gas pipelines and federal, state and local environmental laws and regulations;
- The impact of energy efficiency programs on sales and margins;
- Wholesale commodity prices of electricity and natural gas;
- Increasing depreciation and related property taxes; and
- Federal, state, and local taxes.

Regulation of PSE Rates and Recovery of PSE Costs. The rates that PSE is allowed to charge for its services influence its financial condition, results of operations and liquidity. PSE is highly regulated and the rates that it charges its retail customers are approved by the Washington Commission. The Washington Commission requires these rates be determined based, to a large extent, on historic test year costs plus weather normalized assumptions about hydroelectric conditions and power costs in the relevant rate year. Incremental customer growth and sales typically do not provide sufficient revenue to cover year-to-year cost growth, thus rate increases are required. If, in a particular year, PSE's costs are higher than what is allowed to be recovered in rates, revenue may not be sufficient to permit PSE to earn its allowed return. In addition, the Washington Commission determines whether expenses and investments are reasonable and prudent in providing electric and natural gas service. If the Washington Commission determines that part of PSE's costs do not meet the standard applied, those costs may be disallowed partially or entirely and not recovered in rates.

Electric Rates

PSE has a PCA mechanism that provides for the recovery of power costs from customers or refunding of power cost savings to customers in the event those costs vary from the "power cost baseline" level of power costs. The "power cost baseline" levels are set, in part, based on normalized assumptions about weather and hydroelectric conditions. Excess power costs or power cost savings are apportioned between PSE and its customers pursuant to the graduated scale set forth in the PCA mechanism.

The graduated scale is as follows:

Annual Power Cost Variability	Customers' Share	Company's Share
+/- $20 million	0%	100%
+/- $20 million - $40 million	50%	50%
+/- $40 million - $120 million	90%	10%
+/- $120 + million	95%	5%

PSE had a favorable PCA imbalance for the year ended December 31, 2012, which was $27.4 million below the "power cost baseline" level, $3.7 million of which was apportioned to customers. This compares to a favorable imbalance of $38.1 million for the year ended December 31, 2011, $9.0 million of which was apportioned to customers.

On February 2, 2013, PSE filed an expedited rate filing in which it requested to increase electric rates by $31.9 million or 1.6% for electric customers. PSE made this filing consistent with the expedited filing methodology proposed by Commission Staff and commented on favorably by the Commission in PSE's 2011 general rate case. PSE requested that the tariffs for the expedited rate filing become effective April 1, 2013.

On May 20, 2010, PSE filed an accounting petition requesting that the Washington Commission approve: (1) the creation of a regulatory asset account for the prepayments made to the BPA associated with network upgrades to the Central Ferry substation related to the Lower Snake River wind project; (2) the monthly accrual of carrying charges on that regulatory asset at PSE's approved net of tax rate of return; and (3) the ability to provide customers the BPA interest received through a reduction to transmission expense.

The Washington Commission issued an order in 2010 relating to how REC proceeds should be handled for regulatory accounting and ratemaking purposes. The order required REC proceeds net of applicable costs to be recorded as regulatory liabilities and that amounts recorded would accrue interest. In its petition, PSE had sought approval for $21.1 million of REC proceeds to be used as an offset against its California wholesale energy sales regulatory asset. In response to the order, PSE adjusted the carrying value of its regulatory asset in the second quarter of 2010 by $17.8 million (from $21.1 million to $3.3 million), with the $3.3 million then offset against the Company's RECs regulatory liability. The Company's California wholesale energy sales regulatory asset represented unpaid bills for power sold into the markets maintained by the California Independent System Operator during the 2000-2001 California Energy Crisis, the claims of which were settled along with all counterclaims against PSE in a settlement agreement approved by the FERC on July 1, 2009. The Washington Commission ordered that parties provide recommended methods for passing back the remaining deferred proceeds. The Commission approved a joint proposal that allowed a portion of the REC proceeds received by PSE to offset the Production Tax Credits (PTCs) that had been passed through to customers but have not been used by PSE on its tax return, and after completion of the PTC offset, the Commission allowed PSE to offset the REC liability against rate base and amortize the balance of RECs at the beginning of a given rate year over five years as a credit to cost of service.

On May 7, 2012, the Washington Commission issued its order in PSE's electric general rate case filed in June 2011, approving a general rate increase for electric customers of $63.3 million or 3.2% annually. The rate increases for electric customers became effective May 14, 2012. In its order, the Washington Commission approved a weighted cost of capital of 7.8% and a capital structure that included 48.0% common equity with a return on equity of 9.8%. PSE's requested treatment of the prepayments made to BPA, filed in May 2010, was approved in the order. The final order rejected PSE's proposed conservation savings adjustment. Finally, a new rate rider for RECs was proposed by settlement of Electric parties and approved by the Washington Commission in the final order. The new rate rider replaced prospectively what was required pursuant to the Commission's orders in 2010.

On April 2, 2010, the Washington Commission issued its order in PSE's consolidated electric rate case filed in May 2009 which approved a general rate increase for electric customers of 3.7% annually, or $74.1 million, effective April 8, 2010. In its order, the Washington Commission approved a weighted cost of capital of 8.1% and a capital structure that included 46.0% common equity with an after-tax return on equity of 10.1%.

For additional information, see Note 3 to the consolidated financial statements included in Item 8 of this report.

Natural Gas Rates

PSE has a PGA mechanism that allows PSE to recover expected natural gas supply and transportation costs and defer, as a receivable or liability, any natural gas supply and transportation costs that exceed or fall short of this expected natural gas cost amount in PGA mechanism rates, including accrued interest. 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 natural gas cost through rates.

On February 2, 2013, PSE filed an expedited rate filing in which it requested to decrease natural gas rates by $1.2 million or 0.1% for natural gas customers. PSE made this filing consistent with the expedited filing methodology proposed by Commission Staff and commented on favorably by the Commission in PSE's 2011 general rate case. PSE requested that the tariffs for the expedited rate filing become effective April 1, 2013.

On October 31, 2012, the Washington Commission suspended PSE's PGA natural gas tariff filing and instituted an investigation, but allowed the requested rate decrease under the PGA to go into effect on a temporary basis effective November 1, 2012, subject to revision. Commission Staff is required to report back to the Commission on the status of Staff's investigation no later than March 1, 2013, and that report shall include recommendations on the disposition of the tariff PSE filed or the need for further process to make the appropriate determination. The estimated revenue impact of the change is a decrease of $77.0 million, or 7.7% annually. The rate adjustment has no impact on PSE's net income

On May 7, 2012, the Washington Commission issued its order in PSE's natural gas general rate case filed in June 2011, approving a general rate increase for natural gas customers of $13.4 million or 1.3% annually. The rate increases for natural gas customers became effective May 14, 2012. In its order, the Washington Commission approved a weighted cost of capital of 7.8% and a capital structure that included 48.0% common equity with a return on equity of 9.8%.

On March 14, 2011, the Washington Commission issued its order authorizing PSE to increase its natural gas general tariff rates by $19.0 million or 1.8% on an annual basis effective April 1, 2011.

On April 2, 2010, the Washington Commission issued its order, effective April 8, 2010, in PSE's natural gas general rate case filed in May 2009, approving a general rate increase of 0.8% annually or $10.1 million. In its order, the Washington Commission approved a weighted cost of capital of 8.1% and a capital structure that included 46.0% common equity with an after-tax return on equity of 10.1%.

For additional information, see Note 3 to the consolidated financial statements included in Item 8 of this report.

Weather Conditions. Weather conditions in PSE's service territory have a significant impact on customer energy usage, affecting PSE's revenue and energy supply expenses. PSE's operating revenue and associated energy supply expenses are not generated evenly throughout the year. While both PSE's electric and natural gas sales are generally greatest during winter months, variations in energy usage by customers occur from season to season and month to month within a season, primarily as a result of weather conditions. PSE normally experiences its highest retail energy sales, and subsequently higher power costs, during the winter heating season in the first and fourth quarters of the year and its lowest sales in the third quarter of the year. Varying wholesale electric prices and the amount of hydroelectric energy supplies available to PSE also make quarter-to-quarter comparisons difficult. PSE reported lower customer usage in the twelve months ended December 31, 2012 primarily due to Pacific Northwest temperatures being warmer as compared to the same period in the prior year. The actual average temperature during the twelve months ended December 31, 2012 was 52.0 degrees, or 1.3 degrees warmer than the same period in the prior year. Although the average temperature during the twelve months ended December 31, 2012 was warmer than the same period in the prior year, the average temperature was 0.7 degrees cooler when compared to the historical average.

Customer Demand. PSE expects the number of natural gas customers to grow at rates slightly above electric customers. PSE also expects energy usage by both residential electric and natural gas customers to continue a long-term trend of slow decline primarily due to continued energy efficiency improvements.

Access to Debt Capital. PSE relies on access to bank borrowings and short-term money markets as sources of liquidity and longer-term capital markets to fund its utility construction program, to meet maturing debt obligations and other capital expenditure requirements not satisfied by cash flow from its operations or equity investment from its parent, Puget Energy. Neither Puget Energy nor PSE have any debt outstanding whose maturity would accelerate upon a credit rating downgrade. However, a ratings downgrade could adversely affect the Company's 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 increase as their respective credit ratings decline due to increases in credit spreads and commitment fees. If PSE is unable to access debt 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. PSE monitors the credit environment and expects to continue to be able to access the capital markets to meet its short-term and long-term borrowing needs. PSE's credit facilities expire in 2018 and Puget Energy's senior secured credit facility expires in 2017. (See discussion on credit facilities in the section entitled “Financing Program - Credit Facilities and Commercial Paper”).

Regulatory Compliance Costs and Expenditures. PSE’s operations are subject to extensive federal, state and local laws and regulations. Such regulations cover electric system reliability, gas pipeline system safety and energy market transparency, among other areas. Environmental laws and regulations related to air and water quality (including climate change) and endangered species protection, waste handling and disposal (including generation byproducts such as coal ash), remediation of contamination and siting new facilities also impact the Company’s operations. PSE must spend significant amounts fulfilling requirements by regulatory agencies, many of which have greatly expanded mandates, and on measures including, but not limited to, resource planning, remediation, monitoring, pollution control equipment and emissions-related abatement and fees in order to comply with these regulatory requirements.

Compliance with these or other future regulations, such as those pertaining to climate change and generation byproducts could require significant capital expenditures by PSE and may adversely affect PSE's financial position, results of operations, cash flows and liquidity.

Other Challenges and Strategies

Energy Supply. As noted in PSE's IRP filed with the Washington Commission, PSE projects future energy needs will begin to exceed current resources by 2015 from long-term power purchase agreements and Company-controlled power resources. The IRP identifies reductions in contractual supplies of energy and capacity available under certain long-term power purchase agreements, requiring replacement of supplies to meet projected demands. Therefore, PSE's IRP sets forth a multi-part strategy of implementing energy efficiency programs and pursuing additional renewable resources (primarily wind) and additional base load natural gas-fired generation to meet the growing needs of its customers. If PSE cannot acquire needed energy supply resources at a reasonable cost, it may be required to purchase additional power in the open market at a cost that could, in the absence of regulatory relief, significantly increase its expenses and reduce earnings and cash flows.

Infrastructure Investment. PSE is investing in its utility infrastructure and customer service functions in order to meet regulatory requirements, serve customers' energy needs and replace aging infrastructure. These investments and operating requirements give rise to significant growth in depreciation, amortization and operating expenses, which are not recovered through the ratemaking process in a timely manner. This "regulatory lag" is expected to continue for the foreseeable future.

Operational Risks Associated With Generating Facilities. PSE owns and operates coal, natural gas-fired, hydroelectric, wind-powered, solar and oil-fired generating facilities. Operation of electric generating facilities involves risks that can adversely affect energy output and efficiency levels, including facility shutdowns due to equipment and process failures or fuel supply interruptions. PSE does not have business interruption insurance coverage to cover replacement power costs.

Energy Efficiency Related Lost Sales Margin. PSE's sales, margins, earnings and cash flow are adversely affected by its energy efficiency programs, many of which are mandated by law. The Company is evaluating strategies and other means to reduce or eliminate these adverse financial effects.

Markets For Intangible Power Attributes. The Company is actively engaged in monitoring the development of the commercial markets for such intangible power attributes as RECs and carbon financial instruments. The Company supports the development of regional and national markets for these products that are open, transparent and liquid.

RESULTS OF OPERATIONS

Puget Sound Energy

The following discussion should be read in conjunction with the audited consolidated financial statements and the related notes included elsewhere in this document. The following discussion provides the significant items that impacted PSE's results of operations for the years ended December 31, 2012 and 2011. Set forth below is the consolidated financial results of PSE for the years ended December 31, 2012, 2011 and 2010:

Puget Sound Energy	Year Ended December 31,			Year Ended December 31,	
(Dollars in Thousands)	2012	2011	Favorable/ (Unfavorable)	2010	Favorable/ (Unfavorable)
Operating revenue:					
Electric					
Residential sales	$ 1,112,727	$ 1,144,165	(2.7)%	$ 1,078,262	6.1 %
Commercial sales	853,096	853,880	(0.1)%	836,957	2.0 %
Industrial sales	109,083	108,247	0.8 %	103,678	4.4 %
Other retail sales, including unbilled revenue	25,519	17,651	44.6 %	12,787	38.0 %
Total retail sales	2,100,425	2,123,943	(1.1)%	2,031,684	4.5 %
Transportation sales	9,790	10,275	(4.7)%	11,000	(6.6)%
Sales to other utilities and marketers	23,709	45,726	(48.1)%	62,943	(27.4)%
Other	(5,694)	(32,724)	82.6 %	1,842	*
Total electric operating revenue	2,128,230	2,147,220	(0.9)%	2,107,469	1.9 %
Gas					
Residential sales	712,805	760,441	(6.3)%	648,649	17.2 %
Commercial sales	313,051	344,326	(9.1)%	301,083	14.4 %
Industrial sales	31,344	34,867	(10.1)%	33,004	5.6 %
Total retail sales	1,057,200	1,139,634	(7.2)%	982,736	16.0 %
Transportation sales	15,434	15,017	2.8 %	14,082	6.6 %
Other	13,461	14,199	(5.2)%	14,713	(3.5)%
Total gas operating revenue	1,086,095	1,168,850	(7.1)%	1,011,531	15.6 %
Non-utility operating revenue	1,934	3,733	(48.2)%	3,217	16.0 %
Total operating revenue	3,216,259	3,319,803	(3.1)%	3,122,217	6.3 %
Operating expenses:					
Energy costs:					
Purchased electricity	622,288	771,983	19.4 %	774,007	0.3 %
Electric generation fuel	204,956	199,471	(2.7)%	268,147	25.6 %
Residential exchange	(73,555)	(71,147)	3.4 %	(75,109)	(5.3)%
Purchased gas	538,612	622,088	13.4 %	535,933	(16.1)%
Net unrealized (gain) loss on derivative instruments	(119,120)	54,146	320.0 %	166,953	67.6 %
Utility operations and maintenance	512,765	497,921	(3.0)%	486,701	(2.3)%
Non-utility expense and other	9,977	11,147	10.5 %	11,159	0.1 %
Depreciation	337,952	299,597	(12.8)%	292,634	(2.4)%
Amortization	55,819	72,381	22.9 %	71,572	(1.1)%
Conservation amortization	114,177	107,646	(6.1)%	90,109	(19.5)%
Taxes other than income taxes	319,399	323,527	1.3 %	292,520	(10.6)%
Total operating expenses	2,523,270	2,888,760	12.7 %	2,914,626	0.9 %
Operating income	692,989	431,043	60.8 %	207,591	107.6 %
Other income	49,056	58,041	(15.5)%	45,153	28.5 %
Other expense	(11,770)	(5,380)	(118.8)%	(5,673)	5.2 %
Interest expense	(224,797)	(201,467)	(11.6)%	(220,854)	8.8 %
Income before income taxes	505,478	282,237	79.1 %	26,217	*
Income tax expense	149,308	78,117	(91.1)%	122	*
Net income	$ 356,170	$ 204,120	74.5 %	$ 26,095	*%

* *Not meaningful*

Non-GAAP Financial Measures – Electric and Gas Margins

The following discussion includes financial information prepared in accordance with 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 an understanding of PSE's operating performance. Electric margin and gas margin are used by PSE to determine whether PSE is collecting the appropriate amount of energy costs from its customers to allow recovery of operating costs. PSE's 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.

Electric Margin

The following table displays the details of PSE's electric margin changes from periods 2011 to 2012 and periods 2010 to 2011. Electric margin represents electric sales to retail and transportation customers less the cost of generating and purchasing electric energy sold to customers, including transmission costs to bring electric energy to PSE's service territory.

Electric Margin (Dollars in Thousands)	Year Ended December 31, 2012	Year Ended December 31, 2011	Percent Change	Year Ended December 31, 2010	Percent Change
Electric operating revenue:					
Residential sales	$ 1,112,727	$ 1,144,165	(2.7)%	$ 1,078,262	6.1 %
Commercial sales	853,096	853,880	(0.1)%	836,957	2.0 %
Industrial sales	109,083	108,247	0.8 %	103,678	4.4 %
Other retail sales, including unbilled revenues	25,519	17,651	44.6 %	12,787	38.0 %
Total retail sales	2,100,425	2,123,943	(1.1)%	2,031,684	4.5 %
Transportation sales	9,790	10,275	(4.7)%	11,000	(6.6)%
Sales to other utilities and marketers	23,709	45,726	(48.1)%	62,943	(27.4)%
Other	(5,694)	(32,724)	(82.6)%	1,842	*
Total electric operating revenues[1]	2,128,230	2,147,220	(0.9)%	2,107,469	1.9 %
Minus power costs:					
Purchased electricity[1]	(622,288)	(771,983)	(19.4)%	(774,007)	(0.3)%
Electric generation fuel[1]	(204,956)	(199,471)	2.7 %	(268,147)	(25.6)%
Residential exchange[1]	73,555	71,147	3.4 %	75,109	(5.3)%
Total electric power costs	(753,689)	(900,307)	(16.3)%	(967,045)	(6.9)%
Electric margin[2]	$ 1,374,541	$ 1,246,913	10.2 %	$ 1,140,424	9.3 %

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 $127.6 million and $106.5 million for the years ended December 31, 2012 and December 31, 2011, respectively. Following is a discussion of significant items that impact electric operating revenue and electric energy costs which are included in electric margin:

2012 compared to 2011

Electric Operating Revenue

Electric operating revenues decreased $19.0 million, or 0.9%, to $2,128.2 million from $2,147.2 million for the year ended December 31, 2012 as compared to the same period in 2011. Operating revenue decreased $19.0 million primarily due to lower electric retail sales of $23.5 million and lower sales to other utilities and marketers of $22.0 million offset by higher miscellaneous other operating revenue of $27.0 million. These items are discussed in detail below.

Electric retail sales decreased $23.5 million, or 1.1%, to $2,100.4 million from $2,123.9 million for the year ended December 31, 2012 as compared to the same period in 2011. Electric retail sales decreased due to a $35.3 million decrease in retail electricity usage of 357,640 MWhs, or 1.7%, primarily due to warmer temperatures in PSE's service territory during the year ended December 31, 2012 as compared to the same period in the prior year. The actual average temperature during the year ended December 31, 2012 was 52.0 degrees, or 1.3 degrees warmer than the same period in 2011. Although the average temperature during the year ended December 31, 2012 was warmer than the same period in the prior year, the average temperature was 0.7 degrees cooler when compared to the historical average. Partially offsetting the decrease was a $11.8 million net increase in retail sales due to the electric rate increase effective May 14, 2012 and various pass-through tariff items that have no impact to earnings. The net increase included tariff items, such as the suspension of REC credits in 2011 which contributed an increase of $14.8 million in electric retail sales for the year ended December 31, 2012. The REC credit to customers is offset in other electric operating revenue with no impact to earnings. PSE's customers received credits effective November 1, 2010 through April 30, 2011.

Sales to other utilities and marketers decreased $22.0 million for the year ended December 31, 2012 as compared to the same period in 2011. The decrease was primarily due to a reduction in sales volume of 421,394 MWhs, or 23.3% which decreased revenue $10.6 million and a decline in wholesale electricity prices which decreased revenue by $11.4 million.

Other electric operating revenue increased $27.0 million for the year ended December 31, 2012 as compared to the same period in 2011. For the year ended December 31, 2012, other electric operating revenues increased primarily due to lower losses on non-core gas sales of $37.1 million and a reduction to revenue offsets which contributed increases of $80.3 million in revenue related to PTCs, which are deferred until PSE utilizes the tax credit on its tax return. Partially offsetting the increase is a decrease in REC revenue of $93.5 million. As discussed above, REC revenue is an offset of the REC credit provided to PSE's customers in electric retail sales with no impact to earnings.

Electric Energy Costs

Purchased electricity expense decreased $149.7 million, or 19.4%, for the year ended December 31, 2012 as compared to the same period in 2011. The decrease in purchased electricity expense for the year ended December 31, 2012 was primarily the result of a decrease of $182.6 million related to the expiration of long-term firm purchase contracts that was replaced with market price power and wind generation. In addition, a decrease of $6.2 million was due to a decrease in the overrecovery of power costs, which is shared with customers in accordance with the PCA mechanism, for the year ended December 31, 2012 as compared to the year ended December 31, 2011. Partially offsetting this decrease was a $25.1 million increase related to energy purchase agreements and $8.4 million in additional costs recognized in order to offset the deferral of variable costs related to the Lower Snake River project prior to the inclusion of the plant in rates.

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 as well as through other risk management techniques.

Electric generation fuel expense increased $5.5 million, or 2.7%, for the year ended December 31, 2012 as compared to the same period in 2011. The increase was primarily due to increased generation from PSE's combustion turbine facilities due to the decrease in hydroelectric and wind generation of 904,423 MWhs, or 11.9%, and the decrease in electric generation at the Colstrip facility of 401,059 MWhs, or 9.5% as compared to the same period in 2011. As a result of lower wholesale gas prices it was more economical to generate gas fired electricity from PSE's combustion turbine facilities resulting in an increase in natural gas costs of $8.2 million as compared to the same period in 2011. Offsetting the increase was $2.7 million decrease due to the reduction in Colstrip facility's generation. The decrease in electric generation at the Colstrip facility was primarily due to two coal plants that were taken offline for maintenance and reintroduced at a later point in time into production as other sources of electric generation were considered more economical.

Residential exchange credits decreased $2.4 million, or 3.4%, for the year ended December 31, 2012 as compared to the same period in 2011 as a result of lower electric residential and farm customer sales volumes associated with the BPA REP. The REP credit is a pass-through tariff item with a corresponding credit in electric operating revenue, with no impact on net income.

2011 compared to 2010

Electric Operating Revenue

Electric operating revenue increased $39.8 million, or 1.9%, to $2,147.2 million from $2,107.5 million for the year ended December 31, 2011 as compared to the same period in 2010. The increase in operating revenue of $39.8 million was primarily due to higher electric retail sales of $92.3 million offset by lower sales to other utilities and marketers of $17.2 million and by lower miscellaneous operating revenue of $34.6 million. These items are discussed in detail below.

Electric retail sales increased $92.3 million, or 4.5%, to $2,123.9 million from $2,031.7 million for the year ended December 31, 2011 as compared to the same period in 2010. The increase in electric retail sales was due to a $57.7 million increase in retail electricity usage of 595,487 MWhs, or 2.8%, primarily due to cooler temperatures in PSE's service territory during the year ended December 31, 2011 as compared to the same period in the prior year. The average temperature during the year ended December 31, 2011 was 50.7 degrees, or 1.54 degrees colder than the same period in the prior year, which resulted in a 13.1% increase in heating degree days. Additionally, the electric rate increase effective April 8, 2010 contributed $25.9 million to the increase in electric retail sales. Also contributing to the increase in retail sales were pass-through items with no impact to earnings including a $11.5 million increase in conservation rider program rates, a $7.7 million decrease related to the suspension of the PTC tariff credit effective July 1, 2010, a $4.1 million decrease in the residential exchange rate credit and various other pass-through items. PTCs that are generated and provided to customers are recorded as a reduction in other electric operating revenue until PSE utilizes the tax credit on its tax return, at which time the PTCs will be credited to customers in retail sales. Additionally, PSE's customers were credited $10.5 million for REC revenue, effective November 1, 2010, resulting in a decrease in electric retail sales. The $10.5 million credit to customers is offset in other electric operating revenue with no impact to earnings. PSE's customers continued to receive credits through April 30, 2011.

Sales to other utilities and marketers decreased $17.2 million for the year ended December 31, 2011 as compared to the same period in 2010. The decrease was primarily due to a reduction in sales volumes of 687,124 MWhs, or 27.5% which decreased revenue $22.2 million and a decline in wholesale electricity prices which decreased revenue by $12.8 million. Additionally, in the prior year there was a carrying value adjustment of $17.8 million related to PSE's California wholesale energy sales regulatory asset that did not occur in 2011.

Other electric operating revenue decreased $34.6 million for the year ended December 31, 2011 as compared to the same period in 2010. For the year ended December 31, 2011, the decrease was primarily due to a decrease in non-core gas sales of $21.7 million and a decrease of $85.5 related to PTCs, partially offset by an increase in REC revenue of $67.0 million, PTCs are deferred until PSE utilizes the tax credit on its tax return. As discussed above, REC revenue is an offset of the REC credit provided to PSE's customers in electric retail sales with no impact to earnings.

Electric Energy Costs

Purchased electricity expense decreased $2.0 million, or 0.3%, for the year ended December 31, 2011 as compared to the same period in 2010. The decrease in purchased electricity expense for the year ended December 31, 2011 was primarily the result of lower wholesale market prices, which contributed $180.6 million to the decrease. This decrease was offset by an increase in purchased power of 3,217,631 MWhs, or 23.2%, resulting in an increase of $160.3 million, which was driven by cooler temperatures during the year ended December 31, 2011 as compared to the same period in the prior year. In addition the decrease was offset by an overrecovery of power costs from customers of $9.0 million for the year ended December 31, 2011, which reduced the customer PCA deferral as compared to an underrecovery of power costs of $7.2 million in the same period in 2010. The overrecovery of power costs was due to above-average hydroelectric and wind generation resulting in decreased power costs associated with purchased electricity and fuel costs of PSE's combustion turbines.

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 as well as through other risk management techniques.

Electric generation fuel expense decreased $68.7 million, or 25.6%, for the year ended December 31, 2011 as compared to the same period in 2010. The decrease was primarily due to lower volumes of electricity generation from PSE's combustion turbine facilities as a result of increases in hydroelectric and wind generation of 1,219,910 MWhs, or 19.2%. Also, coal generation at Colstrip decreased 987,522 MWhs, or 19.0% for the year ended December 31, 2011 as compared to the same period in 2010. Generation fuel costs were also lower, due to low wholesale market prices, as it was more economical to purchase wholesale energy than to generate energy from PSE's combustion turbine facilities.

Residential exchange credits decreased $4.0 million, or 5.3%, for the year ended December 31, 2011 as compared to the same period in 2010 as a result of lower electric residential and farm customer sales volumes associated with the BPAREP. The REP credit is a pass-through tariff item with a corresponding credit in electric operating revenue, with no impact on net income.

Natural Gas Margin

The following table displays the details of PSE's natural gas margin changes from 2011 to 2012 and 2010 to 2011. Gas margin is natural gas sales to retail and transportation customers less the cost of natural gas purchased, including transportation costs to bring natural gas to PSE's service territory.

Natural Gas Margin (Dollars in Thousands)	Year Ended December 31, 2012	Year Ended December 31, 2011	Percent Change	Year Ended December 31, 2010	Percent Change
Gas operating revenue:					
Residential sales	$ 712,805	$ 760,441	(6.3)%	$ 648,649	17.2 %
Commercial sales	313,051	344,326	(9.1)%	301,083	14.4 %
Industrial sales	31,344	34,867	(10.1)%	33,004	5.6 %
Total retail sales	$ 1,057,200	$ 1,139,634	(7.2)%	$ 982,736	16.0 %
Transportation sales	15,434	15,017	2.8 %	14,082	6.6 %
Other	13,461	14,199	(5.2)%	14,713	(3.5)%
Total gas operating revenues[1]	$ 1,086,095	$ 1,168,850	(7.1)%	$ 1,011,531	15.6 %
Minus purchased gas costs[1]	$ (538,612)	$ (622,088)	(13.4)%	$ (535,933)	16.1 %
Natural gas margin[2]	$ 547,483	$ 546,762	0.1 %	$ 475,598	15.0 %

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.*

Natural gas margin increased $0.7 million and $71.2 million for the years ended December 31, 2012 and December 31, 2011, respectively. Following is a discussion of significant items that impact gas operating revenue and gas energy costs which are included in natural gas margin:

2012 compared to 2011

Gas Operating Revenue

Gas operating revenue decreased $82.8 million, or 7.1%, to $1,086.1 million from $1,168.9 million for the year ended December 31, 2012 as compared to the same period in 2011. The decrease in gas operating revenue of $82.8 million was due primarily to lower natural gas retail sales revenue of $82.4 million due to lower natural gas costs. These items are discussed in detail below.

Natural gas retail sales revenue decreased $82.4 million, or 7.2%, to $1,057.2 million from $1,139.6 million for the year ended December 31, 2012 as compared to the same period in 2011. The decrease in natural gas retail sales for the year ended December 31, 2012 as compared to the same period in 2011 was primarily due to a decrease of 50.8 million in therm sales, or 5.3%, due to warmer temperatures that resulted in a $60.6 million revenue decrease. The actual average temperature during the year ended December 31, 2012 was 52.0 degrees, or 1.3 degrees warmer than the same period in the prior year. Although the average temperature during the year ended December 31, 2012 was warmer than the same period in the prior year, the temperature was 0.7 degrees cooler when compared to the historical average. Contributing to the decrease was a net $28.5 million decrease related to the PGA rate decreases effective November 1, 2011 and November 1, 2012. The PGA rate decreases were offset by the gas rate increases effective April 1, 2011 and May 14, 2012. Partially offsetting these decreases was a $6.9 million increase in retail sales related to gas conservation revenues with no impact to earnings. 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 net income is not affected by changes under the PGA mechanism.

Gas Energy Costs

Purchased gas expense decreased $83.5 million, or 13.4%, for the year ended December 31, 2012 as compared to the same period in 2011. The decrease was primarily due to lower natural gas costs reflected in PGA rates which was effective November 1, 2011 and November 1, 2012. Also contributing to the expense decrease was a reduction in customer usage of 5.3% as a result of warmer temperatures for the year ended December 31, 2012, as compared to the same period in 2011.

The PGA mechanism provides the rates used to determine natural gas costs based on customer usage. The rate decrease was the result of decreasing costs of wholesale natural gas. The PGA mechanism allows PSE to recover expected natural gas supply and transportation costs and defer, as a receivable or liability, any natural gas supply and transportation costs that exceed or fall short of this expected natural gas cost amount in PGA mechanism rates, including accrued interest. 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 natural gas cost through rates. A payable balance reflects overrecovery of natural gas cost through rates. The PGA mechanism payable balance at December 31, 2012 was $32.6 million, which will be recovered from customers through a future PGA rate filing.

2011 compared to 2010

Gas Operating Revenue

Gas operating revenue increased $157.3 million, or 15.6%, to $1,168.9 million from $1,011.5 million for the year ended December 31, 2011 as compared to the same period in 2010. The increase in gas operating revenue of $157.3 million was due primarily to higher natural gas retail sales of $156.9 million.

Natural gas retail sales increased $156.9 million, or 16.0%, to $1,139.6 million from $982.7 million for the year ended December 31, 2011 as compared to the same period in 2010. The increase consists of $132.6 million due to an increase in gas therms of 131.3 million, or 12.5% as a result of cooler temperatures. Also contributing is an increase of $42.5 million due to a 1.8% increase in natural gas general rate effective April 8, 2010 and a 0.8% PGA rate increase effective November 1, 2010. The increase was offset $10.9 million due to a 4.3% PGA rate decrease effective November 1, 2011. 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 net income is not affected by changes under the PGA mechanism.

Gas Energy Costs

Purchased gas expense increased $86.2 million, or 16.1%, for the year ended December 31, 2011 as compared to the same period in 2010. The increase was primarily due to higher natural gas costs reflected in PGA rates effective November 1, 2010. In addition, an increase in customer usage of 12.5% for the year ended December 31, 2011 as compared to the same period in 2010 contributed to the increase of costs. The PGA mechanism provides the rates used to determine natural gas costs based on customer usage. The rate increase was the result of increasing costs of wholesale natural gas. The PGA mechanism allows PSE to recover expected natural gas supply and transportation costs and defer, as a receivable or liability, any natural gas supply and transportation 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, 2011 was $25.9 million as compared to a receivable balance of $6.0 million at December 31, 2010. 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.

2012 compared to 2011

Other Operating Expenses

Net unrealized gain on derivative instruments increased by $173.3 million to a net gain of $119.1 million for the year ended December 31, 2012 as compared to a loss of $54.1 million during the same period in 2011. The net gain is primarily due to the settlement of contracts with unrealized losses from previous periods which resulted in gains. These gains are offset by losses due to declining natural gas and wholesale electricity prices. Forward prices of electricity and natural gas decreased by 9.0% and 6.3%, respectively, for the year ended December 31, 2012.

Utility operations and maintenance expense increased $14.8 million, or 3.0%, for the year ended December 31, 2012 as compared to the same period in 2011. The increase was primarily driven by increases in customer service expenses of $3.2 million, $2.6 million in administration and general expenses and $7.4 million in electric transmission and distribution expenses for year ended December 31, 2012. The increase in electric transmission and distribution expense was due primarily to the January storm. Additionally, PSE deferred approximately $60.4 million in transmission and distribution expenses related to the January 2012 winter storm as a regulatory asset for future recovery.

Depreciation expense increased $38.4 million, or 12.8%, for the year ended December 31, 2012 as compared to the same period in 2011. The increase was primarily due to additional capital expenditures placed into service, net of retirements, such as the Lower Snake River wind generation facility.

Amortization expense decreased $16.6 million, or 22.9%, for the year ended December 31, 2012 as compared to the same period in 2011. The decrease was primarily due to reductions of $3.5 million for the year ended December 31, 2012 related to the Goldendale electric generating facility (Goldendale) thermal facility deferred costs being fully amortized in 2011 and $3.8

million decrease in common plant amortization. Additionally, a $9.4 million decrease for the year ended December 31, 2012 was due to the Lower Snake River wind generation facility.

Conservation amortization increased $6.5 million, or 6.1%, for the year ended December 31, 2012 as compared to the same period in 2011. The increase was due to an approved accounting petition authorizing PSE to recover costs associated with the Company's current 2012 gas conservation programs via transfers from amounts deferred for the over-recovery commodity costs in the Company's PGA commodity account. Conservation amortization is a pass-through tariff item with no impact on earnings.

Taxes other than income taxes decreased $4.1 million, or 1.3%, for the year ended December 31, 2012 as compared to the same period in 2011. The decrease was primarily due to a decrease in revenue sensitive taxes due to a decrease in retail sales and partially offset by an increase in property taxes.

Other Income, Interest Expense and Income Tax Expense

Other income decreased $9.0 million, or 15.5%, for the year ended December 31, 2012 as compared to the same period in 2011. The decrease for the year ended December 31, 2012, was primarily due to decreases of $10.2 million in AFUDC equity income, $15.9 million in regulatory interest, and $3.0 million of miscellaneous items. Partially offsetting the decrease for the year ended December 31, 2012 is an increase due to the carrying costs associated with the Lower Snake River wind generating facility accruing interest income of $20.3 million, as authorized by the Washington Commission.

Other Expense increased $6.4 million, or 118.8%, for the year ended December 31, 2012 as compared to the same period in 2011. The increase was primarily due to a $2.4 million increase related to customer credits resulting from the outages due to the January 2012 winter storm and $2.5 million related to civic affiliated activities.

Interest expense increased $23.3 million, or 11.6%, for the year ended December 31, 2012 as compared to the same period in 2011. The increase was primarily due to an increase in long term debt which contributed $11.3 million for the year ended December 31, 2012. Also contributing to the increase is a $7.7 million decrease in debt component of AFUDC and a $3.8 million increase in other interest for the year ended December 31, 2012.

Income tax expense increased $71.2 million, or 91.1%, for the year ended December 31, 2012 as compared to the same period in 2011. The increase was primarily related to higher pre-tax income.

2011 compared to 2010

Other Operating Expenses

Net unrealized (gain) loss on derivative instruments decreased by $112.8 million to a loss of $54.1 million in 2011 as compared to a loss of $166.9 million during the same period in 2010. In 2011, the derivative portfolio experienced a significant number of 2010 contracts settling. As those contracts settled, the previous losses recorded in 2010 were reversed resulting in reduced losses between years. On July 1, 2009, PSE elected to de-designate its energy related derivative contracts previously designated as cash flow hedges. The de-designated contracts were physical electric supply contracts and natural gas swap contracts used to fix the price of natural gas for electric generation. For these contracts and for contracts initiated after such date, all mark-to-market accounting impacts are recognized through earnings. The amount previously recorded in accumulated OCI is transferred to earnings when the contracts settle or sooner, if management determines that the forecasted transaction is probable of not occurring. As a result, PSE will continue to experience the earnings impact of these reversals from OCI in future periods. Over the tenor of PSE's outstanding derivative contracts, the forward wholesale prices of electricity and natural gas declined 25.7% and 23.0%, respectively, from December 31, 2010 to December 31, 2011.

Utility operations and maintenance expense increased $11.2 million, or 2.3%, for the year ended December 31, 2011 as compared to the same period in 2010. The increase was driven by increases of $11.9 million increase in electric production, $6.2 in administration and general expenses and $1.5 million in gas operations costs. Partially offsetting the increase is a $7.3 million decrease in electric transmission and distribution and a $1.7 million decrease in customer service expenses.

Depreciation expense increased $7.0 million, or 2.4%, for the year ended December 31, 2011 as compared to the same period in 2010. The increase was primarily due to additional electrical and common utility capital expenditures placed into service, net of retirements.

Conservation amortization increased $17.5 million, or 19.5%, for the year ended December 31, 2011 as compared to the same period in 2010. The increase was due to a 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 $31.0 million, or 10.6%, for the year ended December 31, 2011 as compared to the same period in 2010. The increase was primarily due to an increase in revenue sensitive taxes due to an increase in retail sales.

Other Income, Interest Expense and Income Tax Expense

Other income increased $12.9 million, or 28.5%, for the year ended December 31, 2011 as compared to the same period in 2010. The increase is primarily due to income related to the equity component of AFUDC. AFUDC increased $21.1 million for the year ended December 31, 2011, reflecting an increase in the average construction work in progress balance in 2011 due primarily to construction of wind and hydroelectric generation construction projects. This increase was partially offset by decreases in regulatory interest of $5.4 million, PTC of $1.2 million and conservative incentive of $1.2 million.

Interest expense decreased $19.4 million, or 8.8%, for the year ended December 31, 2011 as compared to the same period in 2010. Contributing to the decrease was a increase of $15.8 million in the debt component of Allowance For Funds Used During Construction (AFUDC) for the year ended December 31, 2011 which was included as construction expenditures and which was due to an increase in the average construction work in progress balance in 2011. Also contributing to the decrease is $3.2 million due to lower interest expense on the REC liability owed to customers.

Income tax expense increased $78.0 million for the year ended December 31, 2011 as compared to the same period in 2010. The increase was primarily related to higher pre-tax income.

Puget Energy

All the operations of Puget Energy are conducted through its subsidiary PSE. Puget Energy's net income for the years ended December 31, 2012, 2011 and 2010 was as follows:

Benefit/(Expense) (Dollars in Thousands)	Year Ended December 31, 2012	Year Ended December 31, 2011	2012-2011 Percent Change	Year Ended December 31, 2010	2011-2010 Percent Change
PSE net income	$ 356,170	$ 204,120	74.5 %	$ 26,095	*
Other operating revenue	(1,103)	(1,037)	(6.4)%	—	*
Purchased electricity	—	578	*	578	— %
Net unrealized gain on derivative instruments	14,486	42,652	(66.0)%	112,858	(62.2)%
Non-utility expense and other	9,165	1,704	*	(12,793)	113.3 %
Other income	12	10	20.0 %	43	(76.7)%
Unhedged interest rate derivative expense	(4,288)	(28,601)	85.0 %	(7,955)	*
Interest expense [1]	(145,204)	(140,493)	(3.4)%	(86,156)	(63.1)%
Income tax benefit (expense)	44,583	44,357	0.5 %	(2,359)	*
Puget Energy net income	$ 273,821	$ 123,290	122.1 %	$ 30,311	*

* *Not meaningful*

1 *Puget Energy's interest expense includes elimination adjustments of intercompany interest on short-term debt.*

2012 compared to 2011

Summary Results of Operations

Puget Energy's net income for 2012 was $273.8 million with operating revenue of $3,215.2 million as compared to net income of $123.3 million with operating revenue of $3,318.8 million for 2011. The following are significant factors that impacted Puget Energy's net income which are not included in PSE's discussion:

Net unrealized gain on derivative instruments decreased $28.2 million for the year ended December 31, 2012, as compared to the same period in 2011, due to the effects of purchase accounting on derivative contracts in other comprehensive income of $18.7 million and the fair value amortization of Normal Purchase Normal Sale (NPNS) derivative contracts of $9.5 million.

Non-utility expense and other costs increased $7.5 million for the year ended December 31, 2012, as compared to the same period in 2011, due primarily to pension expense.

Unhedged interest rate derivative expense decreased $24.3 million for the year ended December 31, 2012, as compared to the same period in 2011. The decrease was primarily due to a gain of $10.4 million related to the mark-to-market on the outstanding interest rate swaps. Additionally, in February and May, 2012 the outstanding interest rate swap balances were reduced by $277.4 million and $550 million, respectively; resulting in a decrease of $13.9 million in interest expense.

Interest expense increased $4.7 million for the year ended December 31, 2012, as compared to the same period in 2011. The increase was primarily due to a $6.4 million increase in write-off related to the unamortized issuance costs associated with the five-year term loan and capital expenditure credit facility. Also contributing to the increase was $16.5 million of interest expense related to additional debt balances. Partially offsetting the increase is a $18.3 million decrease related to mark-to-market on interest rate swap contracts.

2011 compared to 2010

Summary Results of Operations

Puget Energy's net income for 2011 was $123.3 million with operating revenue of $3,318.8 million as compared to net income of $30.3 million with operating revenue of $3,122.2 million for 2010. The following are significant factors that impacted Puget Energy's net income which are not included in PSE's discussion:

Net unrealized gain on derivative instruments decreased $70.2 million for the year ended December 31, 2011, as compared to the same period in 2010, due to the effects of purchase accounting and the fair value amortization of derivative contracts. The forward prices of electricity and natural gas declined 25.7% and 23%, respectively for the year ended December 31, 2011.

Non-utility expense and other costs decreased $14.5 million for the year ended December 31, 2011, as compared to the same period in 2010, due primarily to the write down of SO2 emissions allowance inventory of $9.0 million in 2010 that did not occur in 2011. Also contributing to this decrease is a $4.9 million change related to qualified pension plan which resulted in a gain in 2011.

Unhedged interest rate derivative expense increased $20.6 million for the year ended December 31, 2011, as compared to the same period in 2010, as a result of paying down a portion of a five-year term-loan due February 2014 in December 2010 and during 2011. The five-year variable rate term-loan was initially fully hedged; however a portion of the hedge was unwound during the current year ended December 31, 2011.

Interest expense increased $54.3 million for the year ended December 31, 2011, as compared to the same period in 2010 due to increased out standing debt. In December 2010 and during 2011, Puget Energy issued fixed rate notes with higher interest rates to refinance and extend the debt maturity of a portion of a five-year term-loan due February 2014.

Income tax expense decreased $46.7 million for the year ended December 31, 2011, as compared to the same period in 2010, due primarily to higher pre-tax loss.

CAPITAL RESOURCES AND LIQUIDITY

Capital Requirements

Contractual Obligations and Commercial Commitments

The following are PSE's and Puget Energy's aggregate contractual obligations as of December 31, 2012:

Contractual Obligations (Dollars in Thousands)	Payments Due Per Period Total	2013	2014- 2015	2016- 2017	Thereafter
Energy purchase obligations [1]	$ 7,508,733	$ 976,700	$ 1,663,085	$ 1,398,504	$ 3,470,444
Long-term debt including interest [2]	8,947,447	240,353	613,181	655,369	7,438,544
Short-term debt including interest [7,8]	210,625	210,625	—	—	—
Service contract obligations [3]	334,220	58,832	100,784	138,240	36,364
Non-cancelable operating leases [4]	162,877	16,238	30,456	34,239	81,944
PSE capital leases [4]	27,198	8,160	16,320	2,718	—
Pension and other benefits funding and payments [5]	72,641	26,766	9,833	7,851	28,191
Total PSE contractual cash obligations	$ 17,263,741	$ 1,537,674	$ 2,433,659	$ 2,236,921	$ 11,055,487
Long-term debt, including interest [6]	2,636,503	101,203	202,406	621,680	1,711,214
Less: Inter-company short-term debt and interest elimination [7]	(29,608)	(29,608)	—	—	—
Total Puget Energy contractual cash obligations	$ 19,870,636	$ 1,609,269	$ 2,636,065	$ 2,858,601	$ 12,766,701

1 *Energy purchase contracts were entered into as part of PSE's obligation to serve retail electric and natural gas customers' energy requirements. As a result, costs are generally recovered either through base retail rates or adjustments to retail rates as part of the power and natural gas cost adjustment mechanisms.*

2 *For individual long-term debt maturities, see Note 6 to the consolidated financial statements included in Item 8 of this report. For Puget Energy the amount above excludes the fair value adjustments related to the merger.*

3 *Represents operational agreements, settlements and other contractual obligations with respect to generation, transmission and distribution facilities. These costs are generally recovered through base retail rates.*

4 *For additional information, see Note 8 to the consolidated financial statements included in Item 8 of this report.*

5 *Pension and other benefit expected contributions represent PSE's estimated cash contributions to the pension plan through 2017.*

6 *As of December 31, 2012, Puget Energy had incurred a $434.0 million draw under its $1.0 billion Puget Energy revolving credit facility.*

7 *As of December 31, 2012, PSE has a revolving credit facility with Puget Energy in the form of a promissory note to borrow up to $30.0 million of which $29.6 million was drawn.*

8 *As of December 31, 2012, PSE had credit facilities totaling $1.15 billion and no amount had been drawn. These facilities consisted of $400.0 million to fund operating expenses, $400.0 million to fund capital expenditures and $350.0 million to support electric and natural gas hedging. As of December 31, 2012, two letters of credit totaling $9.6 million in support of contracts were outstanding under the facility, and $181.0 million was outstanding under the commercial paper program. The $400.0 million capital expenditure facility had no amounts drawn and outstanding. No amounts were drawn or outstanding (including letters of credit) under PSE's $350.0 million facility supporting energy hedging. Outside of the credit agreements, PSE had a $4.9 million letter of credit in support of a long-term transmission contract. On February 4, 2013, PSE entered into two new credit facilities and terminated its previous three credit facilities. The new credit facilities provide, in aggregate, $1.0 billion of short-term liquidity needs. These facilities consist of a $650.0 million revolving liquidity facility (which includes a liquidity letter of credit facility and a swingline facility) to be used for general corporate purposes, including a backstop to the Company's commercial paper program and a $350.0 million revolving energy hedging facility (which includes an energy hedging letter of credit facility). The $650.0 million liquidity facility includes a swingline feature allowing same day availability on borrowings up to $75.0 million.The new credit facilities also have an accordion feature that, upon the banks' approval, would increase the total size of these facilities to $1.5 billion.*

The following are PSE's and Puget Energy's aggregate availability under commercial commitments as of December 31, 2012:

Commercial Commitments (Dollars in Thousands)	Amount of Available Commitments Expiration Per Period Total	2013	2014- 2015	2016- 2017	Thereafter
PSE working capital facility [1]	$ 390,400	$ —	$ 390,400	$ —	$ —
PSE capital expenditures facility [1]	400,000	—	400,000	—	—
PSE energy hedging facility [1]	350,000	—	350,000	—	—
Inter-company short-term debt [2]	402	402	—	—	—
Total PSE commercial commitments	$1,140,802	$ 402	$1,140,400	$ —	$ —
Puget Energy revolving credit facility [3]	566,000	—	566,000	—	—
Less: Inter-company short-term debt elimination [2]	(402)	(402)	—	—	—
Total Puget Energy commercial commitments	$1,706,400	$ —	$1,706,400	$ —	$ —

1 *As of December 31, 2012, PSE had credit facilities totaling $1.15 billion and no amount had been drawn. Two letters of credit totaling $9.6 million in support of contracts were outstanding under the facility, and $181.0 million was outstanding under the commercial paper program. The $400.0 million capital expenditure facility had no amounts drawn and outstanding. No amounts were drawn or outstanding (including letters of credit) under PSE's $350.0 million facility supporting energy hedging. Outside of the credit agreements, PSE had a $4.9 million letter of credit in support of a long-term transmission contract. On February 4, 2013, PSE entered into two new credit facilities and terminated its previous three credit facilities. The new credit facilities provide, in aggregate, $1.0 billion of short-term liquidity needs. These facilities consist of a $650.0 million revolving liquidity facility (which includes a liquidity letter of credit facility and a swingline facility) for general corporate purposes, including a backstop to the Company's commercial paper program and a $350.0 million revolving energy hedging facility (which includes an energy hedging letter of credit facility). The $650.0 million liquidity facility includes a swingline feature allowing same day availability on borrowings up to $75.0 million.*

2 *As of December 31, 2012, PSE had a revolving credit facility with Puget Energy in the form of a promissory note to borrow up to $30.0 million of which $29.6 million was drawn.*

3 *As of December 31, 2012, Puget Energy had incurred a $434.0 million draw under its $1.0 billion Puget Energy revolving credit facility. Concurrent with the closing of the new PSE credit facilities in February 2013, the Company reduced the size of Puget Energy's credit facility from $1.0 billion to $800.0 million. The Puget Energy revolving credit facility also has an accordion feature that, upon the banks' approval, would increase the size of the facility to $1.3 billion. All other terms and conditions of that facility remain unchanged.*

Utility Construction Program

PSE's construction programs for generating facilities, the electric transmission system and the natural gas and electric distribution systems are designed to meet regulatory requirements and customer growth and to support reliable energy delivery. Construction expenditures, excluding equity AFUDC, totaled $859.8 million in 2012. Presently planned utility construction expenditures, excluding AFUDC, are as follows:

Capital Expenditure Projections (Dollars in Thousands)	2013	2014	2015
Total energy delivery, technology and facilities expenditures	$ 521,427	$ 514,331	$ 565,341

The program is subject to change based upon general business, economic and regulatory conditions. Utility construction expenditures and any new generation resource expenditures may be funded from a combination of sources which may include cash from operations, short-term debt, long-term debt and/or equity. PSE's planned capital expenditures may result in a level of spending that exceeds its cash flow from operations. As a result, execution of PSE's strategy is dependent in part on continued access to capital markets.

Capital Resources

Cash From Operations

<u>**Puget Sound Energy**</u>

Cash generated from operations for the year ended December 31, 2012 increased by $0.5 million from $903.4 million generated during the same period in 2011. The increase in cash flow was primarily the result of an increase in net income of $152.1 million and the following increases:

- Cash collections from revenues increased by $41.5 million.

- Payments made in 2011 relating to transmission prepayments for the Lower Snake River wind generation facility and the purchase of combustion turbine inventory that did not occur in 2012, which caused an increase in cash flow of approximately $27.0 million.

The increase in cash generated from operating activities in 2012 described above was primarily offset by the following cash decreases:

- In 2012, there was approximately $66.8 million of cash outflow for costs incurred related to the January winter storm of which $60.4 million was deferred for future recovery.
- Tax refunds received decreased by $48.1 million in 2012.
- Increase in payments of $26.7 million related to energy and operational costs.
- Increase in pension funding of $17.8 million.

In addition, non cash items decreased approximately $173.3 million related to the fair value adjustment of derivative instruments; this was partially offset by an increase in items such as depreciation, amortization, and deferred income taxes and credits of approximately $96.2 million.

Puget Energy

Cash generated from operations for the year ended December 31, 2012 was $888.7 million, a decrease of $121.6 million from the $1.0 billion generated during the year ended December 31, 2011. The net decrease included a $0.5 million increase from the cash provided by the operating activities of PSE as previously discussed. The factors contributing to the decrease included the following:

- As a result of the merger with Puget Holdings in February 2009, $92.7 million in derivative settlement payments were reclassified to financing activities for the year-to-date ended December 31, 2012 as compared to $182.7 million during the same period in 2011, resulting in a decrease in operating cash flows of $90.0 million. This decrease was due to a decline in the number of contracts settled during 2012 as compared to the prior period. These contracts represent proceeds received from derivative instruments that included financing elements at the merger date.
- Tax refund received by Puget Energy of $13.6 million in 2011 as compared to no refund received in 2012.

Financing Program

The Company's external financing requirements principally reflect the cash needs of its construction program, its schedule of maturing debt and certain operational needs. The Company anticipates refinancing the redemption of bonds or other long-term borrowings with its credit facilities and/or the issuance of new long-term debt. Access to funds depends upon factors such as Puget Energy's and PSE's credit ratings, prevailing interest rates and investor receptivity to investing in the utility industry, Puget Energy and PSE.

Credit Facilities and Commercial Paper

Proceeds from PSE's short-term borrowings and sales of commercial paper are used to provide working capital and the interim funding of utility construction programs. Puget Energy and PSE continue to have reasonable access to the capital and credit markets.

As of December 31, 2012 and 2011, PSE had $181.0 million and $25.0 million in short-term debt outstanding, respectively, exclusive of the demand promissory note with Puget Energy. Outside of the consolidation of PSE's short-term debt, Puget Energy had no short-term debt outstanding in either year as borrowings under its credit facilities are classified as long-term. PSE's weighted-average interest rate on short-term debt, including borrowing rate, commitment fees and the amortization of debt issuance costs, during 2012 and 2011 was 6.49%, and 4.39%, respectively. As of December 31, 2012, PSE and Puget Energy had several committed credit facilities that are described below.

Puget Sound Energy Credit Facilities

At December 31, 2012, PSE maintained three committed unsecured revolving credit facilities that provided, in the aggregate, $1.15 billion in short-term borrowing capability and which were due to mature concurrently in February 2014. These facilities included 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. The credit agreements allowed PSE to borrow at the bank's prime rate or to make floating rate advances at the LIBOR plus a spread that was based upon PSE's credit rating. The working capital facility, as amended, included a swing line feature allowing same day availability on borrowings up to $50.0 million. The $400.0 million working capital facility and $350.0 million credit agreement to support energy hedging allowed for issuing standby letters of credit. PSE paid a commitment fee on the unused portion of the credit facilities. The spreads and the commitment fee depended on PSE's credit ratings. As of December 31, 2012, the spread to the LIBOR was 0.85% and the commitment fee was 0.26%. The $400.0 million working capital facility also serves as a backstop for PSE's commercial paper program. As of December 31, 2012, PSE maintained its investment grade ratings and was in compliance with all applicable covenants. As of December 31, 2012, no amounts were drawn and outstanding under PSE's $400.0 million working capital facility. Two letters of credit totaling $9.6 million in support of contracts were outstanding under the facility, and $181.0 million was outstanding under the commercial paper program. The $400.0 million capital expenditure facility had no amounts drawn and outstanding. No amounts were drawn or outstanding (including letters of credit) under PSE's $350.0 million facility supporting energy hedging. Outside of the unsecured revolving credit agreements, PSE had a $4.9 million letter of credit in support of a long-term transmission contract.

On February 4, 2013, PSE entered into two new unsecured revolving credit facilities and terminated its previous three credit facilities. The new credit facilities provide, in aggregate, $1.0 billion of short-term liquidity needs. These facilities consist of a $650.0 million revolving liquidity facility (which includes a liquidity letter of credit facility and a swingline facility) to be used for general corporate purposes, including a backstop to the Company's commercial paper program and a $350.0 million revolving energy hedging facility (which includes an energy hedging letter of credit facility). The $650.0 million liquidity facility includes a swingline feature allowing same day availability on borrowings up to $75.0 million. The new credit facilities also have an accordion feature that, upon the banks' approval, would increase the total size of these facilities to $1.5 billion.

The credit agreements for these two replacement credit facilities contain similar terms and conditions and are syndicated among numerous lenders and mature in February 2018. The credit agreements contain usual and customary affirmative and negative covenants that, among other things, place limitations on PSE's ability to incur additional indebtedness and liens, issue equity, pay dividends, transact with affiliates and make asset dispositions and investments. The credit agreements also contain a financial covenant of total debt to total capitalization of 65% or less. The credit agreements provide PSE with the ability to borrow at different interest rate options. The credit agreements allow PSE to borrow at the bank's prime rate or to make floating rate advances at the LIBOR plus a spread that is based upon PSE's credit rating. PSE must pay a commitment fee on the unused portion of the credit facilities. The spreads and the commitment fee depend on PSE's credit ratings. As of the date of this report, the spread to the LIBOR is 1.50% and the commitment fee is 0.225%.

Demand Promissory Note. On June 1, 2006, PSE entered into a revolving credit facility with Puget Energy, in the form of a credit agreement and a Demand Promissory Note (Note) pursuant to which 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 lower of the weighted-average interest rates of PSE’s outstanding commercial paper interest rate or PSE’s senior unsecured revolving credit facility. Absent such borrowings, interest is charged at one-month LIBOR plus 0.25%. At December 31, 2012, the outstanding balance of the Note was $29.6 million. The outstanding balance and the related interest under the Note are eliminated by Puget Energy upon consolidation of PSE’s financial statements.

Puget Energy Credit Facilities

At the time of the merger in February 2009, Puget Energy entered into a $1.225 billion five-year term-loan and a $1.0 billion five-year capital expenditure credit facility for funding capital expenditures. On February 10, 2012, Puget Energy entered into a $1.0 billion five-year revolving senior secured credit facility. As a revolving facility, amounts borrowed may be repaid without a reduction in the size of the facility. Initial borrowings under this facility were used to repay debt outstanding under the term loan and capital expenditure credit facility and those agreements were terminated.

The five-year revolving senior secured credit facility contains usual and customary affirmative and negative covenants. The agreement also contains two financial covenants based on the following ratios: Group Funds From Operations (FFO) Coverage Ratio and Maximum Leverage Ratio, as defined in the agreement governing the senior secured credit facility. As of December 31, 2012, Puget Energy was in compliance with all applicable covenants.

The senior secured credit facility provides Puget Energy the ability to borrow at different interest rate options and includes variable fee levels. Interest rates may be based on the prime rate or LIBOR, plus a spread based on Puget Energy’s credit ratings. Puget Energy must pay a commitment fee on the unused portion of the facility. At December 31, 2012, $434.0 million was drawn and outstanding under the facility, the spread over LIBOR was 2.0% and the commitment fee was 0.375%. Puget Energy entered into interest rate swap contracts to manage the interest rate risk associated with the credit facility (see Note 9 and the "Interest Rate Risk" sections).

Concurrent with the closing of the new PSE credit facilities in February 2013, the Company reduced the size of Puget Energy's credit facility from $1.0 billion to $800.0 million. The Puget Energy revolving credit facility also has an accordion feature that, upon the banks' approval, would increase the size of the facility to $1.3 billion. All other terms and conditions of that facility remain unchanged from when it was committed in 2012.

Dividend Payment Restrictions

The payment of dividends by PSE to Puget Energy is restricted by provisions of certain covenants applicable to long-term debt contained in PSE’s electric and natural gas mortgage indentures. At December 31, 2012, approximately $551.7 million of unrestricted retained earnings was available for the payment of dividends under the most restrictive mortgage indenture covenant.

Beginning February 6, 2009, pursuant to the terms of the Washington Commission merger order, PSE may not declare or pay dividends if PSE’s common equity ratio, calculated on a regulatory basis, is 44.0% or below except to the extent a lower equity ratio is ordered by the Washington Commission. Also, pursuant to the merger order, PSE may not declare or make any distribution unless on the date of distribution PSE’s corporate credit/issuer rating is investment grade, or, if its credit ratings are below investment grade, PSE’s ratio of EBITDA to interest expense for the most recently ended four fiscal quarter periods prior to such date is equal to or greater than 3 to one. The common equity ratio, calculated on a regulatory basis, was 48.0% at December 31, 2012 and the EBITDA to interest expense was 4.5 to one for the 12 months then ended.

PSE’s ability to pay dividends is also limited by the terms of its credit facilities, pursuant to which PSE is not permitted to pay dividends during any Event of Default, or if the payment of dividends would result in an Event of Default (as defined in the facilities), such as failure to comply with certain financial covenants.

Puget Energy’s ability to pay dividends is also limited by the merger order issued by the Washington Commission as well as by the terms of its credit facilities. Pursuant to the 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 four most recently ended fiscal quarters prior to such date is equal to or greater than 2 to one. At December 31, 2012, the EBITDA to interest expense was 2.7 to one for the 12 months then ended.

At December 31, 2012, the Company was in compliance with all applicable covenants, including those pertaining to the payment of dividends.

Debt Restrictive Covenants

The type and amount of future long-term financings for PSE are limited by provisions in PSE's credit agreements and mortgage indentures. Under its credit agreements, PSE’s long-term debt issuances cannot exceed $500.0 million per year, plus any amount needed to refinance maturing bonds. Unused amounts under this limitation may be carried forward into future years.

PSE’s ability to issue additional secured debt may also be limited by certain restrictions contained in its electric and natural gas mortgage indentures. Under the most restrictive tests, at December 31, 2012, PSE could issue:

- Approximately $1.4 billion of additional first mortgage bonds under PSE’s electric mortgage indenture based on approximately $2.3 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, 2012; and
- Approximately $271.0 million of additional first mortgage bonds under PSE’s natural gas mortgage indenture based on approximately $451.7 million of gas bondable property available for issuance, subject to a combined gas and electric interest coverage test of 1.75 times net earnings available for interest and a gas interest coverage test of 2.0 times net earnings available for interest (as defined in the natural gas utility mortgage), both of which PSE exceeded at December 31, 2012.

At December 31, 2012, PSE had approximately $6.5 billion in electric and natural gas ratebase to support the interest coverage ratio limitation test for net earnings available for interest.

Upon approval of the merger in 2009, the Company was required to refinance its debt in place at the time of the merger. The Company has met this refinancing requirement as of December 31, 2012.

Shelf Registrations and Long-Term Debt Activity

Puget Sound Energy. PSE has in effect a shelf registration statement under which it may issue, from time to time, senior notes secured by first mortgage bonds. The Company remains subject to the restrictions of PSE’s indentures and credit agreements on the amount of first mortgage bonds that PSE may issue.

Puget Energy. On June 15, 2012, Puget Energy issued $450.0 million of senior secured notes. The notes are secured by substantially all of Puget Energy's assets, which consist primarily of the equity interests it holds in PSE. The notes mature on July 15, 2022 and have an interest rate of 5.625%. Net proceeds from the note offering were used by Puget Energy to pay down $425.0 million of the $859.0 million balance outstanding on a five-year $1.0 billion revolving senior secured credit facility put in place in February 2012.

Other

Critical Accounting Policies And Estimates

The preparation of financial statements in conformity with GAAP 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. Operating utility revenue is recognized when the basis of service is rendered, which includes estimated unbilled revenue. PSE's estimate of unbilled revenue is based on a calculation using meter readings from its automated meter reading (AMR) system. The estimate calculates unbilled usage at the end of each month as the difference between the customer meter readings on the last day of the month and the last customer meter readings billed. The unbilled usage is then priced at published rates for each schedule to estimate the unbilled revenues by customer.

Regulatory Accounting. As a regulated entity of the Washington Commission and the FERC, PSE prepares its financial statements in accordance with the provisions of ASC 980, "Regulated Operations" (ASC 980). The application of ASC 980 results in differences in the timing and recognition of certain revenue 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 the FERC. Under the authority of these commissions, PSE has recorded certain regulatory assets and liabilities at December 31, 2012 in the amount of $936.2 million and $628.9 million, respectively, and regulatory assets and liabilities at December 31, 2011 of $845.5 million and $390.0 million, respectively. Such amounts are amortized through a corresponding liability or asset account, respectively, with no impact to earnings. PSE expects to fully recover its 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 PSE determines that it no longer meets the criteria for continued application of ASC 980, PSE could be required to write off its regulatory assets and liabilities related to those operations not meeting ASC 980 requirements.

Also encompassed by regulatory accounting and subject to ASC 980 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. For further discussion regarding the PCA mechanism, see Electric Regulation and Rates within Item 1. Business – Regulation and Rates of this report. The increases and decreases in the cost of natural gas supply are reflected in customers' bills through the PGA mechanism. 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.

Goodwill. On February 6, 2009, Puget Holdings completed its merger with Puget Energy. Puget Energy remeasured the carrying amount of all its assets and liabilities to fair value, which resulted in recognition of approximately $1.7 billion in goodwill. ASC 350, "Intangibles - Goodwill and Other," (ASC 350) requires that goodwill be tested for impairment at the reporting unit level on an annual basis and between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying value. These events or circumstances could include a significant change in the Company's business or regulatory outlook, legal factors, a sale or disposition of a significant portion of a reporting unit or significant changes in the financial markets which could influence the Company's access to capital and interest rates. Application of the goodwill impairment test requires judgment, including the identification of reporting units, assignment of assets and liabilities to reporting units, assignment of goodwill to reporting units and the determination of the fair value of the reporting units. Management has determined Puget Energy has only one reporting unit.

The goodwill recorded by Puget Energy represents the potential long-term return to the Company's investors. Goodwill is tested for impairment annually using a two-step process. The first step compares the carrying amount of the reporting unit with its fair value, with a carrying value higher than fair value indicating potential impairment. If the first step test fails, the second step is performed. This would entail a full valuation of Puget Energy's assets and liabilities and comparing the valuation to its carrying amounts, with the aggregate difference indicating the amount of impairment. Goodwill of a reporting unit is required to be tested for impairment on an interim basis if an event occurs or circumstances change that would cause the fair value of a reporting unit to fall below its carrying amount.

Puget Energy conducted its most recent annual impairment test as of October 1, 2012. The fair value of Puget Energy's reporting unit was estimated using the weighted-averages from an income valuation method, or discounted cash flow method, and a market valuation approach. These valuations required significant judgments, including: (1) estimation of future cash flows, which is dependent on internal forecasts, (2) estimation of the long-term rate of growth for Puget Energy's business, (3) estimation of the useful life over which cash flows will occur, (4) the selection of utility holding companies determined to be comparable to Puget Energy, and (5) the determination of an appropriate weighted-average cost of capital or discount rate.

Management estimated the fair value of Puget Energy's equity to be approximately $4.0 billion at the October 1, 2012 measurement date for the annual test of goodwill impairment. The carrying value of Puget Energy's equity was approximately $3.4 billion with the excess of the fair value over the carrying value representing 17.5% or $598.0 million.

The income approach and the market approach valuations resulted in Puget Energy equity values of $4.1 billion and $3.9 billion, respectively. The result of the income approach was very sensitive to long-term cash flow growth rates applicable to periods beyond management's five-year business plan and financial forecast period and the weighted-average cost of capital assumptions of 3.0% and 7.0%, respectively.

The following table summarizes the results of the income valuation method:

Equity Value Sensitivity Table
(Dollars in Billions)

Weighted-Average Cost of Capital	Long-Term Growth Rate		
	2.7%	3.0%	3.3%
7.1%	$ 3.2	$ 3.8	$ 4.4
7.0	3.4	4.1	4.8
6.9	3.7	4.4	5.1

Derivatives. ASC 815, "Derivatives and Hedging" (ASC 815), requires that all contracts considered to be derivative instruments be recorded on the balance sheet at their fair value unless the contracts qualify for an exception. The Company enters into derivative contracts to manage its energy resource portfolio and interest rate exposure including forward physical and financial contracts and swaps. Some of PSE's physical electric supply contracts qualify for the NPNS exception to derivative accounting rules. Generally, NPNS applies to contracts with creditworthy counterparties, for which physical delivery is probable and in quantities that will be used in the normal course of business. Power purchases designated as NPNS must meet additional criteria to determine if the transaction is within PSE's forecasted load requirements and if the counterparty owns or controls energy resources within the western region to allow for physical delivery of the energy. PSE may enter into financial fixed contracts to economically hedge the variability of certain index-based contracts. Those contracts that do not meet the NPNS exception are marked-to-market to current earnings in the statements of income. Natural gas derivative contracts qualify for deferral under ASC 980 due to the PGA mechanism.

On July 1, 2009, Puget Energy and PSE elected to de-designate all energy related derivative contracts previously recorded as cash flow hedges for the purpose of simplifying their financial reporting. The contracts that were de-designated related to physical electric supply contracts and natural gas swap contracts used to fix the price of natural gas for electric generation. For these contracts and contracts initiated after such date, all mark-to-market adjustments are recognized through earnings. The amount previously recorded in accumulated OCI is transferred to earnings in the same period or periods during which the hedged transaction affects earnings or sooner if management determines that the forecasted transaction is probable of not occurring. As a result, the Company will continue to experience the earnings impact of these reversals from OCI in future periods.

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 economically 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, hydrological and unit performance conditions.

The Company may enter into swap instruments or other financial derivative instruments to manage the interest rate risk associated with its long-term debt financing and debt instruments. As of December 31, 2012, Puget Energy had interest rate swap contracts outstanding related to its long-term debt. For additional information, see Item 7A and Note 10 to the consolidated financial statements included in Item 8 of this report.

Fair Value. ASC 820, "Fair Value Measurements and Disclosures" (ASC 820), defines fair value as 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 ASC 820, 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 as it believes that this approach is used by market participants for these types of assets and liabilities. Accordingly, the Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. For further discussion on market risk, see Item 7A of this report.

Pension and Other Postretirement Benefits. PSE has a qualified defined benefit pension plan covering substantially all employees of PSE. PSE recognized qualified pension expense of $14.8 million, $6.6 million and $8.0 million for the years ended December 31, 2012, 2011 and 2010, respectively. Of these amounts, approximately 57.2%, 61.0% and 61.1% were included in utility operations and maintenance expense in 2012, 2011 and 2010, respectively, and the remaining amounts were capitalized. For the years ended December 31, 2012 and 2011, Puget Energy recognized incremental qualified pension income of $9.3 million and pension income of $1.9 million, respectively. In 2013, it is expected that PSE and Puget Energy will recognize pension expense of $21.3 million and $16.6 million of pension income, respectively.

PSE has a Supplemental Executive Retirement Plan (SERP). PSE recognized pension and other postretirement benefit expenses of $5.0 million, $5.2 million and $4.5 million for the years ended December 31, 2012, 2011 and 2010, respectively. For the years ended December 31, 2012 and 2011, Puget Energy recognized incremental income of $1.0 million and $1.4 million, respectively. In 2013, it is expected PSE and Puget Energy will recognize $5.7 million of pension expense and $0.8 million of pension income, respectively.

PSE has other limited postretirement benefit plans. PSE recognized expense of $0.3 million, $0.1 million and $0.1 million for the years ended December 31, 2012, 2011 and 2010, respectively. For the years ended December 31, 2012 and 2011, Puget Energy recognized incremental expense of $0.2 million and $0.3 million, respectively. In 2013, it is expected that PSE will recognize expense of $0.3 million and $0.2 million incremental expense for Puget Energy.

The Company's pension and other postretirement benefits income or expense 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 the Company 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 or 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. As required by merger accounting rules, market-related value was reset to market value effective with the merger. During 2012, the Company made a cash contribution of $22.8 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. At December 31, 2012 and 2011, the Company's qualified pension plan was $85.1 million and $86.2 million underfunded as measured under GAAP, or 86.2% and 84.8% funded respectively. As of January 1, 2013, the plan's estimated funded ratio, as calculated under guidelines from The Pension Protection Act of 2006 and considering temporary interest rate relief measures approved by Congress, was more than 100%. The aggregate expected contributions and payments by the Company to fund the retirement plan, SERP and other postretirement plans for the year ending December 31, 2013 are expected to be at least $20.4 million, $5.0 million and $0.8 million, respectively.

The discount rate used in accounting for pension and other benefit obligations decreased from 4.75% in 2011 to 4.15% in 2012. The discount rate used in accounting for pension and other benefit expense decreased from 5.15% in 2011 to 4.75% in 2012. The rate of return on plan assets for qualified pension benefits in 2012 remained unchanged at 2011 level, or 7.75%. The rate of return on plan assets for other benefits decreased from 7.80% in 2011 to 7.50% in 2012. The following tables reflect the estimated sensitivity associated with a change in certain significant actuarial assumptions (each assumption change is presented mutually exclusive of other assumption changes):

Puget Energy and Puget Sound Energy	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	$ (32,913)	$ (2,230)	$ (770)
Decrease in discount rate	50 basis points	36,262	2,400	836

Puget Energy	Change in Assumption	Impact on 2012 Pension Expense Increase /(Decrease)		
(Dollars in Thousands)		Pension Benefits	SERP	Other Benefits
Increase in discount rate	50 basis points	$ (2,412)	$ (219)	$ 22
Decrease in discount rate	50 basis points	2,833	229	(26)
Increase in return on plan assets	50 basis points	(2,542)	*	(35)
Decrease in return on plan assets	50 basis points	2,542	*	34

Puget Sound Energy	Change in Assumption	Impact on 2012 Pension Expense Increase /(Decrease)		
(Dollars in Thousands)		Pension Benefits	SERP	Other Benefits
Increase in discount rate	50 basis points	$ (2,585)	$ (219)	$ (53)
Decrease in discount rate	50 basis points	2,833	229	56
Increase in return on plan assets	50 basis points	(2,645)	*	(35)
Decrease in return on plan assets	50 basis points	2,645	*	34

* *Calculation not applicable.*

Recently Adopted Accounting Pronouncements

For the discussion of recently adopted accounting pronouncements, see Note 2 to the consolidated financial statements included in Item 8 of this report.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Energy Portfolio Management

PSE maintains energy risk policies and procedures to manage commodity and volatility risks and the related effects on credit, tax accounting, financing and liquidity. PSE's Energy Management Committee establishes PSE's risk management policies and procedures and monitors compliance. The Energy Management Committee is comprised of certain PSE officers and is overseen by the PSE Board of Directors.

PSE is focused on the commodity price exposure and risks associated with volumetric variability in the natural gas and electric portfolios and related effects noted above. It is not engaged in the business of assuming risk for the purpose of speculative trading. PSE 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 PSE's natural gas and power portfolios will perform under various weather, hydroelectric 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 PSE's assets; and
- Meet the credit, liquidity, financing, tax and accounting requirements of PSE.

ASC 815 requires a significant amount of disclosure regarding PSE's derivative activities and the nature of their impact on PSE's financial position, financial performance and cash flows. The information in this Item 7A should serve as an accompaniment to Management's Discussion and Analysis and Note 9 to the consolidated financial statements included in Items 7 and 8 of this report, respectively.

PSE employs various energy portfolio optimization strategies, but is not in the business of assuming risk for the purpose of realizing speculative trading revenue. The nature of serving regulated electric customers with its portfolio of owned and contracted electric generation resources exposes PSE and its customers to some volumetric and commodity price risks within the sharing mechanism of the PCA. PSE's natural gas retail customers are served by natural gas purchase contracts which expose PSE's customers to commodity price risks through the PGA mechanism. All purchased natural gas costs are recovered through customer rates with no direct impact on PSE. Therefore, wholesale market transactions and related hedging strategies are focused on balancing PSE's energy portfolio, reducing costs and risks where feasible thus reducing volatility in costs in the portfolio. PSE's energy risk portfolio management function monitors and manages these risks using analytical models and tools. In order to manage risks effectively, PSE enters into forward physical electricity and natural gas purchase and sale agreements, and floating-for-fixed swap contracts that are related to its regulated electric and natural gas portfolios. The forward physical electricity contracts are both fixed and variable (at index) while the physical natural gas contracts are variable with investment grade counterparties that do not require collateral calls on the contracts. To fix the price of wholesale electricity and natural gas, PSE may enter into floating-for-fixed (financial) contracts with various counterparties.

On July 1, 2009, Puget Energy and PSE elected to de-designate all energy related derivative contracts previously recorded as cash flow hedges for the purpose of simplifying its financial reporting. The contracts that were de-designated related to physical electric supply contracts and natural gas swap contracts to fix the price of natural gas for electric generation. For these contracts and for contracts initiated after such date, all mark-to-market adjustments are recognized through earnings. The amount previously recorded in accumulated OCI is transferred to earnings in the same period or periods during which the hedged transaction affected earnings or sooner if management determines that the forecasted transaction is probable of not occurring. As a result, the Company will continue to experience the earnings impact of these reversals from OCI in future periods.

The following table presents the fair value of the Company's energy derivatives instruments that do not meet the NPNS exception :

Puget Energy and Puget Sound Energy (Dollars in Thousands)	December 31, 2012		December 31, 2011	
	Assets	Liabilities	Assets	Liabilities
Electric portfolio:				
Current	$ 3,418	$ 93,097	$ 5,212	$ 173,582
Long-term	6,139	38,096	5,508	90,752
Total electric derivatives	$ 9,557	$ 131,193	$ 10,720	$ 264,334
Natural Gas portfolio:				
Current	$ 3,451	$ 77,851	$ 1,435	$ 128,297
Long-term	8,675	30,227	4,576	78,607
Total natural gas derivatives	$ 12,126	$ 108,078	$ 6,011	$ 206,904
Total energy derivatives	$ 21,683	$ 239,271	$ 16,731	$ 471,238

For further details regarding both the fair value of derivative instruments and the impacts such instruments have on current period earnings and OCI (for cash flow hedges), see Notes 9 and 10 to the consolidated financial statements.

At December 31, 2012, the Company had total assets of $12.1 million and total liabilities of $108.1 million related to derivative contracts used to hedge the supply and cost of natural gas to serve natural gas customers. All fair value adjustments of derivatives relating to the natural gas business have been reclassified to a deferred account in accordance with ASC 980, "Regulated Operations", 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 natural gas costs under the PGA mechanism.

A hypothetical 10.0% increase or decrease in market prices of natural gas and electricity would change the fair value of the Company's derivative contracts by $43.2 million, with an after-tax impact of $28.2 million.

The change in fair value of the Company's outstanding energy derivative instruments from December 31, 2011 through December 31, 2012 is summarized in the table below:

Puget Energy and Puget Sound Energy Energy Derivative Contracts Gain (Loss) (Dollars in Thousands)	
Fair value of contracts outstanding at December 31, 2011	$ (454,507)
Contracts realized or otherwise settled during 2012	337,117
Change in fair value of derivatives	(100,198)
Fair value of contracts outstanding at December 31, 2012	$ (217,588)

The fair value of the Company's outstanding derivative instruments at December 31, 2012, based on pricing source and the period during which the instrument will mature, is summarized below:

Puget Energy and Puget Sound Energy

Source of Fair Value	Fair Value of Contracts by Settlement Year				
(Dollars in Thousands)	2013	2014-2015	2016-2017	Thereafter	Total
Prices provided by external sources [1]	$ (152,476)	$ (29,404)	$ (181)	$ —	$ (182,061)
Prices based on internal models and valuation methods	(11,603)	(18,806)	(4,309)	(809)	(35,527)
Total fair value	$ (164,079)	$ (48,210)	$ (4,490)	$ (809)	$ (217,588)

1 *Prices provided by external pricing service, which utilizes broker quotes and pricing models.*

Contingent Features and Counterparty Credit Risk

PSE 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. PSE manages credit risk with policies and procedures for, among other things, counterparty analysis and measurement, monitoring and mitigation of exposure.

Where deemed appropriate, and when allowed under the terms of the agreements, PSE 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, 2012, PSE held approximately $0.2 million worth of standby letters of credit in support of various electricity and REC transactions.

It is possible that volatility in energy commodity prices could cause PSE to have material credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, PSE could suffer a material financial loss. As of December 31, 2012, approximately 91.8% of PSE's energy and natural gas portfolio exposure, including NPNS transactions, is with counterparties that are rated at least investment grade by the major rating agencies while 8.2% are either rated below investment grade or are not rated by rating agencies. PSE assesses credit risk internally for counterparties that are not rated.

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

PSE 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 PSE'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). ASC 815 specifies the requirements for derivative contracts to qualify for the NPNS scope exception. When performance is no longer probable, PSE records the fair value of the contract on the balance sheet with the corresponding amount recorded in the statements of income.

Accumulated OCI of the cash flow hedge is also impacted by a counterparty's deterioration of credit under ASC 815 guidelines. If a forecasted transaction associated with the cash flow hedge probable of not occurring, PSE will reclassify the amounts deferred in accumulated OCI into earnings.

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

The Company computes credit reserves at a master agreement level by counterparty (i.e. WSPP, ISDA or NAESB). 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 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 the fair value and contract tenors for all deals for each counterparty and arriving at 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. For those in a net liability position, the Company calculates the credit reserve by using its own bond spreads. The fair value of derivative instruments includes the impact of credit reserves. As of December 31, 2012, the Company was in a net liability position with the majority of its counterparties, therefore the default factors of counterparties did not have a significant impact on reserves for the year. Despite its net liability position, PSE was not required to post additional collateral with any of its counterparties. Additionally, PSE did not trigger any collateral requirements with any of its counterparties, nor were any of PSE's counterparties required to post additional collateral resulting from credit rating downgrades.

Interest Rate Risk

The Company believes its interest rate risk primarily relates to the use of short-term debt instruments, variable rate 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 internal cash from operations, borrowings under its commercial paper program, and its credit facilities to meet short-term funding needs. Short-term obligations are commonly refinanced with fixed-rate bonds or notes when needed and when interest rates are considered favorable. The Company may also enter into swap instruments or other financial hedge instruments to manage the interest rate risk associated with these debts. As of December 31, 2012, Puget Energy had two interest rate swap contracts outstanding and PSE did not have any outstanding interest rate swap instruments.

In February 2009, Puget Energy entered into a cash flow hedge using interest rate swaps to hedge risk associated with one-month LIBOR floating rate debt. Subsequently, in order to satisfy a commitment the Company made to the Washington Commission and to mitigate interest rate risk, the Company refinanced a portion of the underlying debt hedged by the interest rate swaps in 2010, 2011, and again during 2012. In order to better align its existing swap notional with the reduced underlying debt balance, in 2012, the Company has net settled $827.4 million of the interest rate swaps, thereby reducing the swap notional to $450.0 million. Additionally, the Company amended the remaining two interest rate swap agreements to extend the maturities to January 2017. As a result of refinancing in 2010, the Company de-designated the cash flow hedge accounting relationship between the debt and interest rate swaps. A portion of the outstanding interest rate swap derivative loss associated with the probable future interest payments occurring remains in OCI, and is amortized monthly as the payments occur. The portion of the outstanding interest rate swap derivative loss associated with interest payments on the debt where future payments become remote of occurring is reclassified from OCI into earnings.

At December 31, 2012, the fair value of the interest rate swaps was a $21.5 million pre-tax loss. The fair value considers the risk of Puget Energy's non-performance by using its incremental borrowing rate on unsecured debt over the risk-free rate in the valuation estimate. The ending balance in OCI includes a loss of $4.6 million pre-tax, and $3.0 million after tax, related to the interest rate swaps previously designated as cash flow hedge. The OCI balance relates to the loss that was recorded when the cash flow hedge was de-designated in December 2010. Currently, all changes in market value are recorded in earnings instead of OCI.

A hypothetical 10% increase or decrease in interest rates would change the fair value of Puget Energy's interest rate swaps by $1.1 million.

The following table presents the fair value of Puget Energy's interest rate swaps:

Puget Energy (Dollars in Thousands)	December 31, 2012		December 31, 2011	
	Assets	Liabilities	Assets	Liabilities
Interest rate swaps:				
Current	$ —	$ 6,571	$ —	$ 25,210
Long-term	—	14,953	—	27,199
Total interest rate swaps	$ —	$ 21,524	$ —	$ 52,409

The change in fair value of Puget Energy's outstanding interest rate swaps from December 31, 2011 through December 31, 2012 is summarized in the table below:

Puget Energy Interest Rate Swap Contracts Gain (Loss) (Dollars in Thousands)	
Fair value of contracts outstanding at December 31, 2011	$ (52,409)
Contracts realized or otherwise settled during 2012	38,516
Change in fair value of derivatives	(7,631)
Fair value of contracts outstanding at December 31, 2012	$ (21,524)

The fair value of Puget Energy's outstanding interest rate swaps at December 31, 2012, based on pricing source and the period during which the instrument will mature, is summarized below:

Source of Fair Value	Fair Value of Contracts by Settlement Year			
(Dollars in Thousands)	2013	2014-2015	2016-2017	Total
Prices provided by external sources [1]	$ (6,571)	$ (11,486)	$ (3,467)	$ (21,524)

[1] *Prices provided by external pricing service, which may utilize broker quotes and internal pricing models. Significant pricing inputs are based on observable market data.*

From time to time PSE may enter into treasury locks or forward starting swap contracts to hedge interest rate exposure related to an anticipated debt issuance. The ending balance in OCI related to the forward starting swaps and previously settled treasury lock contracts at December 31, 2012 was a net loss of $6.6 million after tax and accumulated amortization. This compares to an after-tax loss of $6.9 million in OCI as of December 31, 2011. All financial hedge contracts of this type are reviewed by an officer, presented to the Board of Directors, or a committee of the Board, as applicable and are approved prior to execution. PSE had no treasury locks or forward starting swap contracts outstanding at December 31, 2012.

The following table presents the carrying value and the fair value of the Company's debt instruments :

Puget Energy and Puget Sound Energy	December 31, 2012		December 31, 2011	
(Dollars in Thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial liabilities:				
Short-term debt	$ 181,000	$ 181,000	$ 25,000	$ 25,000
Short-term debt owed by PSE to Puget Energy [1]	29,598	29,598	29,998	29,998
Long-term debt - fixed-rate	4,912,200	6,462,021	4,447,511	5,752,154
Long-term debt – variable rate	434,000	434,000	829,856	856,978
Total Debt	$ 5,556,798	$ 7,106,619	$ 5,332,365	$ 6,664,130

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

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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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 consolidated financial statements or the notes thereto.

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

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 GAAP.

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 designed to ensure the integrity and independence of our financial reporting processes 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/ Kimberly J. Harris	/s/ Daniel A. Doyle	/s/ Michael J. Stranik
Kimberly J. Harris	Daniel A. Doyle	Michael J. Stranik
President and Chief Executive Officer	*Senior Vice President and Chief Financial Officer*	*Controller and Principal Accounting Officer*

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

In our opinion, the consolidated balance sheets and the related consolidated statements of income, comprehensive income, common shareholder's equity and cash flows present fairly, in all material respects, the financial position of Puget Energy, Inc. and its subsidiaries at December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedules, Condensed Financial Information of Puget Energy, Inc. and Valuation and Qualifying Accounts and Reserves, 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, 2012, 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 on 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.

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
Seattle, Washington
March 4, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

In our opinion, the consolidated balance sheets and the related consolidated statements of income, comprehensive income, common shareholder's equity and cash flows present fairly, in all material respects, the financial position of Puget Sound Energy, Inc. and its subsidiaries at December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule of Valuation and Qualifying Accounts and Reserves 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, 2012, 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.

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
Seattle, Washington
March 4, 2013

PUGET ENERGY, INC.
CONSOLIDATED STATEMENTS OF INCOME
(Dollars in Thousands)

	Year Ended December 31,		
	2012	2011	2010
Operating revenue:			
Electric	$ 2,128,230	$ 2,147,220	$ 2,107,469
Gas	1,086,095	1,168,850	1,011,531
Other	831	2,695	3,217
Total operating revenue	3,215,156	3,318,765	3,122,217
Operating expenses:			
Energy costs:			
Purchased electricity	622,288	771,405	773,429
Electric generation fuel	204,956	199,471	268,147
Residential exchange	(73,555)	(71,147)	(75,109)
Purchased gas	538,612	622,088	535,933
Unrealized (gain) loss on derivative instruments, net	(133,606)	11,494	54,095
Utility operations and maintenance	512,765	497,921	486,701
Non-utility expense and other	814	9,442	23,952
Depreciation	337,952	299,597	292,634
Amortization	55,819	72,381	71,572
Conservation amortization	114,177	107,646	90,109
Taxes other than income taxes	319,399	323,527	292,520
Total operating expenses	2,499,621	2,843,825	2,813,983
Operating income	715,535	474,940	308,234
Other income (deductions):			
Other income	49,069	58,052	45,196
Other expense	(11,770)	(5,380)	(5,673)
Non-hedged interest rate derivative expense	(4,288)	(28,601)	(7,955)
Interest charges:			
AFUDC	22,216	29,949	14,157
Interest expense	(392,216)	(371,910)	(321,167)
Income (loss) before income taxes	378,546	157,050	32,792
Income tax (benefit) expense	104,725	33,760	2,481
Net income (loss)	$ 273,821	$ 123,290	$ 30,311

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

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

	Year Ended December 31,		
	2012	2011	2010
Net income (loss)	$ 273,821	$ 123,290	$ 30,311
Other comprehensive income (loss):			
Net unrealized gain (loss) on interest rate swaps during the period, net of tax of $0, $0 and $(31,325), respectively	—	—	(58,175)
Reclassification of net unrealized (gain) loss on interest rate swaps during the period, net of tax of $6,234, $13,700 and $11,860, respectively	11,577	25,443	22,027
Net unrealized gain (loss) from pension and postretirement plans, net of tax of $(7,469), $(29,522) and $2,842, respectively	(13,870)	(54,826)	5,172
Reclassification of net unrealized (gain) loss on energy derivative instruments settled during the period, net of tax of $200, $832 and $2,380, respectively	371	1,545	4,420
Other comprehensive income (loss)	(1,922)	(27,838)	(26,556)
Comprehensive income (loss)	$ 271,899	$ 95,452	$ 3,755

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

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

ASSETS

	December 31, 2012	December 31, 2011
Utility plant (including construction work in progress of $766,035 and $1,282,462, respectively):		
Electric plant	$ 6,750,400	$ 6,090,851
Gas plant	2,385,784	2,238,741
Common plant	487,931	418,236
Less: Accumulated depreciation and amortization	(1,067,424)	(674,783)
Net utility plant	8,556,691	8,073,045
Other property and investments:		
Goodwill	1,656,513	1,656,513
Other property and investments	112,367	123,352
Total other property and investments	1,768,880	1,779,865
Current assets:		
Cash and cash equivalents	135,542	37,235
Restricted cash	3,700	4,183
Accounts receivable, net of allowance for doubtful accounts of $9,932 and $8,495, respectively	287,784	336,530
Unbilled revenue	204,359	191,150
Materials and supplies, at average cost	82,353	76,068
Fuel and gas inventory, at average cost	88,953	100,491
Unrealized gain on derivative instruments	6,869	6,647
Income taxes	4,796	10,970
Prepaid expense and other	13,571	13,969
Power contract acquisition adjustment gain	50,785	65,096
Deferred income taxes	53,437	101,934
Total current assets	932,149	944,273
Other long-term and regulatory assets:		
Regulatory asset for deferred income taxes	119,844	62,305
Power cost adjustment mechanism	3,773	6,818
Regulatory assets related to power contracts	37,655	46,202
Other regulatory assets	815,785	783,580
Unrealized gain on derivative instruments	14,814	10,084
Power contract acquisition adjustment gain	456,225	517,740
Other	95,763	183,394
Total other long-term and regulatory assets	1,543,859	1,610,123
Total assets	$ 12,801,579	$ 12,407,306

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

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

CAPITALIZATION AND LIABILITIES

	December 31, 2012	December 31, 2011
Capitalization:		
Common shareholder's equity:		
Common stock $0.01 par value, 1,000 shares authorized, 200 shares outstanding	$ —	$ —
Additional paid-in capital	3,308,957	3,308,957
Earnings reinvested in the business	208,100	22,873
Accumulated other comprehensive income (loss), net of tax	(32,829)	(30,907)
Total common shareholder's equity	3,484,228	3,300,923
Long-term debt:		
First mortgage bonds and senior notes	3,351,412	3,362,000
Pollution control bonds	161,860	161,860
Junior subordinated notes	250,000	250,000
Long-term debt	1,834,000	1,793,000
Debt discount and other	(264,072)	(289,493)
Total long-term debt	5,333,200	5,277,367
Total capitalization	8,817,428	8,578,290
Current liabilities:		
Accounts payable	288,059	339,361
Short-term debt	181,000	25,000
Current maturities of long-term debt	13,000	—
Purchased gas adjustment liability	32,587	25,940
Accrued expenses:		
Taxes	95,623	90,727
Salaries and wages	38,438	40,892
Interest	82,262	69,329
Unrealized loss on derivative instruments	177,519	327,089
Power contract acquisition adjustment loss	3,902	8,547
Other	72,799	74,409
Total current liabilities	985,189	1,001,294
Long-term and regulatory liabilities:		
Deferred income taxes	1,261,636	1,153,172
Unrealized loss on derivative instruments	83,276	196,558
Regulatory liabilities	600,697	369,403
Regulatory liabilities related to power contracts	507,009	582,836
Power contract acquisition adjustment loss	33,753	37,655
Other deferred credits	512,591	488,098
Total long-term and regulatory liabilities	2,998,962	2,827,722
Commitments and contingencies (Note 16)		
Total capitalization and liabilities	$ 12,801,579	$ 12,407,306

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

PUGET ENERGY, INC.
CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDER'S EQUITY
(Dollars in Thousands)

	Common Stock					
	Shares	Amount	Additional Paid-in Capital	Earnings Reinvested in the Business	Accumulated Other Comprehensive Income (Loss)	Total Equity
Balance at December 31, 2009	200	$ —	$ 3,308,957	$ 91,024	$ 23,487	$ 3,423,468
Net income	—	—	—	30,311	—	30,311
Common stock dividend	—	—	—	(104,311)	—	(104,311)
Other comprehensive income	—	—	—	—	(26,556)	(26,556)
Balance at December 31, 2010	200	$ —	$ 3,308,957	$ 17,024	$ (3,069)	$ 3,322,912
Net income	—	—	—	123,290	—	123,290
Common stock dividend	—	—	—	(117,441)	—	(117,441)
Other comprehensive income	—	—	—	—	(27,838)	(27,838)
Balance at December 31, 2011	200	$ —	$ 3,308,957	$ 22,873	$ (30,907)	$ 3,300,923
Net income	—	—	—	273,821	—	273,821
Common stock dividend	—	—	—	(88,594)	—	(88,594)
Other comprehensive income	—	—	—	—	(1,922)	(1,922)
Balance at December 31, 2012	200	$ —	$ 3,308,957	$ 208,100	$ (32,829)	$ 3,484,228

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

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

	Year Ended December 31, 2012	2011	2010
Operating activities:			
Net income (loss)	$ 273,821	$ 123,290	$ 30,311
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation	337,952	299,597	292,634
Amortization	55,819	72,381	71,572
Conservation amortization	114,177	107,646	90,109
Deferred income taxes and tax credits, net	100,457	31,774	(32,955)
Net unrealized (gain) loss on derivative instruments	(146,680)	45,043	50,495
Derivative contracts classified as financing activities due to merger	92,681	182,710	371,621
AFUDC - equity	(25,469)	(32,431)	(12,677)
Funding of pension liability	(22,800)	(5,000)	(12,000)
Regulatory assets	(64,368)	30,232	26,198
Regulatory liabilities	14,054	21,031	28,821
Other long-term assets	(1,644)	(61,734)	(50,009)
Other long-term liabilities	95,166	46,473	31,944
Change in certain current assets and liabilities:			
Accounts receivable and unbilled revenue	35,537	(5,977)	7,261
Materials and supplies	(6,284)	8,154	(19,378)
Fuel and gas inventory	11,527	(4,852)	3,591
Income taxes	6,174	65,213	58,434
Prepayments and other	393	605	(2,345)
Purchased gas adjustment	6,647	31,932	(55,579)
Accounts payable	(25,963)	1,098	(26,396)
Taxes payable	4,896	9,222	4,203
Accrued expenses and other	32,598	43,921	10,094
Net cash provided by operating activities	888,691	1,010,328	865,949
Investing activities:			
Construction expenditures - excluding equity AFUDC	(859,791)	(976,513)	(859,091)
Energy efficiency expenditures	(106,006)	(94,405)	(95,726)
Treasury grant payment received	205,261	—	28,675
Restricted cash	483	1,287	14,374
Other	(38,923)	(7,184)	6,001
Net cash used in investing activities	(798,976)	(1,076,815)	(905,767)
Financing activities:			
Change in short-term debt and leases, net	148,437	(227,651)	141,941
Dividends paid	(88,594)	(117,441)	(104,311)
Long-term notes and bonds issued	1,314,000	1,382,000	1,025,000
Redemption of bonds and notes	(1,273,000)	(769,000)	(675,000)
Derivative contracts classified as financing activities due to merger	(92,681)	(182,710)	(371,621)
Issuance cost of bonds and other	430	(18,033)	(18,161)
Net cash provided by (used in) financing activities	8,592	67,165	(2,152)
Net increase (decrease) in cash and cash equivalents	98,307	678	(41,970)
Cash and cash equivalents at beginning of period	37,235	36,557	78,527
Cash and cash equivalents at end of period	$ 135,542	$ 37,235	$ 36,557
Supplemental cash flow information:			
Cash payments for interest (net of capitalized interest)	$ 318,305	$ 280,847	$ 278,926
Cash payments (refunds) for income taxes	(1,898)	(64,016)	(22,243)

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

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

	Year Ended December 31,		
	2012	2011	2010
Operating revenue:			
Electric	$ 2,128,230	$ 2,147,220	$ 2,107,469
Gas	1,086,095	1,168,850	1,011,531
Other	1,934	3,733	3,217
Total operating revenue	3,216,259	3,319,803	3,122,217
Operating expenses:			
Energy costs:			
Purchased electricity	622,288	771,983	774,007
Electric generation fuel	204,956	199,471	268,147
Residential exchange	(73,555)	(71,147)	(75,109)
Purchased gas	538,612	622,088	535,933
Unrealized (gain) loss on derivative instruments, net	(119,120)	54,146	166,953
Utility operations and maintenance	512,765	497,921	486,701
Non-utility expense and other	9,977	11,147	11,159
Depreciation	337,952	299,597	292,634
Amortization	55,819	72,381	71,572
Conservation amortization	114,177	107,646	90,109
Taxes other than income taxes	319,399	323,527	292,520
Total operating expenses	2,523,270	2,888,760	2,914,626
Operating income (loss)	692,989	431,043	207,591
Other income (deductions):			
Other income	49,056	58,041	45,153
Other expense	(11,770)	(5,380)	(5,673)
Interest charges:			
AFUDC	22,216	29,949	14,157
Interest expense	(246,811)	(231,212)	(234,793)
Interest expense on parent note	(202)	(204)	(218)
Income (loss) before income taxes	505,478	282,237	26,217
Income tax (benefit) expense	149,308	78,117	122
Net income (loss)	$ 356,170	$ 204,120	$ 26,095

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

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

	Year Ended December 31,		
	2012	2011	2010
Net income (loss)	$ 356,170	$ 204,120	$ 26,095
Other comprehensive income (loss):			
Net unrealized gain (loss) from pension and postretirement plans, net of tax of $(3,911), $(28,474) and $2,446, respectively	(7,294)	(52,927)	3,610
Reclassification of net unrealized (gain) loss on energy derivative instruments, net of tax of $4,500, $11,673 and $26,140	8,358	21,678	48,546
Amortization of treasury interest rate swaps to earnings, net of tax of $171, $171 and $171, respectively	317	317	317
Other comprehensive income (loss)	1,381	(30,932)	52,473
Comprehensive income (loss)	$ 357,551	$ 173,188	$ 78,568

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

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

ASSETS

	December 31, 2012	December 31, 2011
Utility plant (including construction work in progress of $766,035 and $1,282,462, respectively):		
Electric plant	$ 9,048,356	$ 8,413,846
Gas plant	2,998,188	2,855,794
Common plant	555,549	518,318
Less: Accumulated depreciation and amortization	(4,045,402)	(3,714,913)
Net utility plant	8,556,691	8,073,045
Other property and investments:		
Other property and investments	103,646	113,528
Total other property and investments	103,646	113,528
Current assets:		
Cash and cash equivalents	135,530	31,010
Restricted cash	3,700	4,183
Accounts receivable, net of allowance for doubtful accounts of $9,932 and $8,495, respectively	287,989	336,483
Unbilled revenue	204,359	191,150
Materials and supplies, at average cost	82,353	76,069
Fuel and gas inventory, at average cost	85,547	97,074
Unrealized gain on derivative instruments	6,869	6,647
Income taxes	4,796	10,970
Prepaid expenses and other	13,414	13,807
Deferred income taxes	68,015	112,204
Total current assets	892,572	879,597
Other long-term and regulatory assets:		
Regulatory asset for deferred income taxes	119,279	61,344
Power cost adjustment mechanism	3,773	6,818
Other regulatory assets	813,171	777,341
Unrealized gain on derivative instruments	14,814	10,084
Other	90,330	186,386
Total other long-term and regulatory assets	1,041,367	1,041,973
Total assets	$ 10,594,276	$ 10,108,143

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

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

CAPITALIZATION AND LIABILITIES

	December 31, 2012	December 31, 2011
Capitalization:		
Common shareholder's equity:		
Common stock $0.01 par value – 150,000,000 shares authorized, 85,903,791 shares outstanding	$ 859	$ 859
Additional paid-in capital	3,246,205	3,246,205
Earnings reinvested in the business	344,280	163,735
Accumulated other comprehensive income (loss), net of tax	(187,198)	(188,579)
Total common shareholder's equity	3,404,146	3,222,220
Long-term debt:		
First mortgage bonds and senior notes	3,351,412	3,362,000
Pollution control bonds	161,860	161,860
Junior subordinated notes	250,000	250,000
Debt discount and other	(14)	(15)
Total long-term debt	3,763,258	3,773,845
Total capitalization	7,167,404	6,996,065
Current liabilities:		
Accounts payable	288,257	339,568
Short-term debt	181,000	25,000
Short-term note owed to parent	29,598	29,998
Current maturities of long-term debt	13,000	—
Purchased gas adjustment liability	32,587	25,940
Accrued expenses:		
Taxes	95,623	90,727
Salaries and wages	38,438	40,892
Interest	55,806	55,843
Unrealized loss on derivative instruments	170,948	301,879
Other	69,882	68,346
Total current liabilities	975,139	978,193
Long-term and regulatory liabilities:		
Deferred income taxes	1,274,602	1,115,056
Unrealized loss on derivative instruments	68,323	169,359
Regulatory liabilities	596,324	364,085
Other deferred credits	512,484	485,385
Total long-term and regulatory liabilities	2,451,733	2,133,885
Commitments and contingencies (Note 16)		
Total capitalization and liabilities	$ 10,594,276	$ 10,108,143

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

PUGET SOUND ENERGY, INC.
CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDER'S EQUITY
(Dollars in Thousands)

	Common Stock					
	Shares	Amount	Additional Paid-in Capital	Earnings Reinvested in the business	Accumulated Other Comprehensive Income (loss)	Total Equity
Balance at December 31, 2009	85,903,791	$ 859	$ 2,959,205	$ 333,128	$ (210,120)	$ 3,083,072
Net income	—	—	—	26,095	—	26,095
Common stock dividend	—	—	—	(186,733)	—	(186,733)
Other comprehensive income	—	—	—	—	52,473	52,473
Balance at December 31, 2010	85,903,791	$ 859	$ 2,959,205	$ 172,490	$ (157,647)	$ 2,974,907
Net income	—	—	—	204,120	—	204,120
Common stock dividend	—	—	—	(212,875)	—	(212,875)
Capital Contribution	—	—	287,000	—	—	287,000
Other comprehensive income	—	—		—	(30,932)	(30,932)
Balance at December 31, 2011	85,903,791	$ 859	$ 3,246,205	$ 163,735	$ (188,579)	$ 3,222,220
Net income	—	—	—	356,170	—	356,170
Common stock dividend	—	—	—	(175,625)	—	(175,625)
Capital Contribution	—	—	—	—	—	—
Other comprehensive income	—	—	—	—	1,381	1,381
Balance at December 31, 2012	85,903,791	$ 859	$ 3,246,205	$ 344,280	$ (187,198)	$ 3,404,146

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

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

	Year Ended December 31, 2012	2011	2010
Operating activities:			
Net income (loss)	$ 356,170	$ 204,120	$ 26,095
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation	337,952	299,597	292,634
Amortization	55,819	72,381	71,572
Conservation amortization	114,177	107,646	90,109
Deferred income taxes and tax credits, net	145,040	77,174	(16,284)
Net unrealized (gain) loss on derivative instruments	(119,120)	54,146	166,953
AFUDC - equity	(25,469)	(32,431)	(12,677)
Funding of pension liability	(22,800)	(5,000)	(12,000)
Regulatory assets	(64,368)	29,271	26,198
Regulatory liabilities	14,054	21,031	28,821
Other long-term assets	932	(62,682)	(48,258)
Other long-term liabilities	79,789	28,814	1,701
Change in certain current assets and liabilities:			
Accounts receivable and unbilled revenue	35,285	(6,204)	7,584
Materials and supplies	(6,284)	8,154	(19,618)
Fuel and gas inventory	11,527	(4,852)	3,591
Income taxes	6,174	51,144	37,834
Prepayments and other	393	605	(2,345)
Purchased gas adjustment	6,647	31,932	(55,579)
Accounts payable	(25,972)	688	(25,780)
Taxes payable	4,896	9,222	4,203
Accrued expenses and other	(954)	18,666	11,021
Net cash provided by operating activities	903,888	903,422	575,775
Investing activities:			
Construction expenditures - excluding equity AFUDC	(859,791)	(976,513)	(859,091)
Energy efficiency expenditures	(106,006)	(94,405)	(95,726)
Treasury grant payment received	205,261	—	28,675
Restricted cash	483	1,287	14,374
Other	(18,022)	9,043	6,001
Net cash used in investing activities	(778,075)	(1,060,588)	(905,767)
Financing activities:			
Change in short-term debt and leases, net	148,437	(227,651)	141,941
Dividends paid	(175,625)	(212,875)	(186,733)
Long-term notes and bonds issued	—	595,000	575,000
Loan from (payment to) parent	(400)	7,400	(300)
Redemption of bonds and notes	—	(285,000)	(232,000)
Investment from parent	—	287,000	—
Issuance cost of bonds and other	6,295	(12,018)	(10,003)
Net cash provided by (used in) financing activities	(21,293)	151,856	287,905
Net increase (decrease) in cash and cash equivalents	104,520	(5,310)	(42,087)
Cash and cash equivalents at beginning of period	31,010	36,320	78,407
Cash and cash equivalents at end of period	$ 135,530	$ 31,010	$ 36,320
Supplemental cash flow information:			
Cash payments for interest (net of capitalized interest)	$ 216,128	$ 191,666	$ 198,496
Cash payments (refunds) for income taxes	(1,898)	(50,022)	(20,632)

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

(1) Summary of Significant Accounting Policies

Basis of Presentation

Puget Energy, Inc. (Puget Energy) is an energy services holding company that owns Puget Sound Energy, Inc. (PSE). 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. On February 6, 2009, Puget Holdings LLC (Puget Holdings), a consortium of long-term infrastructure investors, completed its merger with Puget Energy (the merger). As a result of the merger, all of Puget Energy's common stock is indirectly owned by Puget Holdings. The acquisition of Puget Energy was accounted for in accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 805, "Business Combinations" (ASC 805), as of the date of the merger. ASC 805 requires the acquirer to recognize and measure identifiable assets acquired and liabilities assumed at fair value as of the merger date.

The 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. PSE's consolidated financial statements continue to be accounted for on a historical basis and PSE's financial statements do not include any ASC 805 purchase accounting adjustments. The preparation of financial statements in conformity with U.S. 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 revenue and expenses during the reporting period. Actual results could differ from those estimates.

Certain prior year amounts have been reclassified to conform to the current year presentation.

Utility Plant

Puget Energy and PSE capitalize, at original cost, additions to utility plant, including renewals and betterments. Costs include indirect costs such as engineering, supervision, certain taxes, pension and other employee benefits and an Allowance For Funds Used During Construction (AFUDC). Replacements of minor items of property and major maintenance are included in maintenance expense when the utility plant is retired and removed from service, the original cost of the property is charged to accumulated depreciation and costs associated with removal of the property, less salvage, are charged to the cost of removal regulatory liability.

Non-Utility Property, Plant and Equipment

For PSE, 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 are 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 recorded for intangibles such as regulatory assets and liabilities, computer software and franchises. The depreciation of automobiles, trucks, power-operated equipment, tools and office equipment is allocated to asset and expense accounts based on usage. The annual depreciation provision stated as a percent of a depreciable electric utility plant was 2.9%, 2.7% and 2.7% in 2012, 2011 and 2010, respectively; depreciable gas utility plant was 3.4%, 3.5% and 3.6% in 2012, 2011 and 2010, respectively; and depreciable common utility plant was 11.6%, 11.3% and 11.8% in 2012, 2011 and 2010, respectively. 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.

Goodwill

On February 6, 2009, Puget Holdings completed its merger with Puget Energy. Puget Energy remeasured the carrying amount of all its assets and liabilities to fair value, which resulted in recognition of approximately $1.7 billion in goodwill. ASC 350, "Intangibles - Goodwill and Other" (ASC 350), requires that goodwill be tested for impairment at the reporting unit level on an annual basis and between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying value. These events or circumstances could include a significant change in the Company's business or regulatory outlook, legal factors, a sale or disposition of a significant portion of a reporting unit or significant changes in the financial markets which could influence the Company's access to capital and interest rates. Application of the goodwill impairment test requires judgment, including the identification of reporting units, assignment of assets and liabilities to reporting units, assignment of goodwill to reporting units and the determination of the fair value of the reporting units. Management has determined Puget Energy has only one reporting unit.

The goodwill recorded by Puget Energy represents the potential long-term return to the Company's investors. Goodwill is tested for impairment annually using a two-step process. The first step compares the carrying amount of the reporting unit with its fair value, with a carrying value higher than fair value indicating potential impairment. If the first step test fails, the second step is performed. This would entail a full valuation of Puget Energy's assets and liabilities and comparing the valuation to its carrying amounts, with the aggregate difference indicating the amount of impairment. Goodwill of a reporting unit is required to be tested for impairment on an interim basis if an event occurs or circumstances change that would cause the fair value of a reporting unit to fall below its carrying amount.

Puget Energy conducted its annual impairment test in 2012 using an October 1, 2012 measurement date. The fair value of Puget Energy's reporting unit was estimated using both discounted cash flow and market approach. Such approaches are considered methodologies that market participants would use. This analysis requires significant judgments, including estimation of future cash flows, which is dependent on internal forecasts, estimation of long-term rate of growth for Puget Energy business, estimation of the useful life over which cash flows will occur, the selection of utility holding companies determined to be comparable to Puget Energy and determination of an appropriate weighted-average cost of capital or discount rate. The market approach estimates the fair value of the business based on market prices of stocks of comparable companies engaged in the same or similar lines of business. In addition, indications of market value are estimated by deriving multiples of equity or invested capital to various measures of revenue, earnings or cash flow. Changes in these estimates and or assumptions could materially affect the determination of fair value and goodwill impairment of the reporting unit. Based on the test performed, management has determined that there was no indication of impairment of Puget Energy's goodwill as of October 1, 2012. There were no events or circumstances from the date of the assessment through December 31, 2012 that would impact management's conclusion.

Cash and Cash Equivalents

Cash and cash equivalents consist of demand bank deposits and short-term highly liquid investments with original maturities of three months or less at the time of purchase. The cash and cash equivalents balance at Puget Energy was $135.5 million and $37.2 million as of December 31, 2012 and 2011, respectively. The 2012 and 2011 balance consisted of cash equivalents, which are reported at cost and approximates fair value, and were $107.6 million and $16.8 million, respectively.

Materials and Supplies

Materials and supplies are used primarily 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. Puget Energy and PSE record these items at weighted-average cost.

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. Puget Energy and PSE record these items at the lower of cost or market value using the weighted-average cost method.

Regulatory Assets and Liabilities

PSE accounts for its regulated operations in accordance with ASC 980 "Regulated Operations" (ASC 980). ASC 980 requires PSE to defer certain costs that would otherwise be charged to expense, if it were probable that future rates will permit recovery of such costs. It similarly requires deferral of revenues or gains and losses that are expected to be returned to customers in the future. Accounting under ASC 980 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, PSE classifies regulatory assets and liabilities as long-term assets or liabilities. The exception is the Purchased Gas Adjustment (PGA) which can be a current asset or current liability.

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 authorized AFUDC rates authorized by the Washington Utilities and Transportation Commission (Washington Commission) for natural gas and electric utility plant additions based on the effective dates is as follows:

Effective Date	Washington Commission AFUDC Rates
May 14, 2012 - present	7.80%
April 8, 2010 - May 13, 2012	8.10
November 1, 2008 - April 7, 2010	8.25

The Washington Commission authorized the Company to calculate AFUDC using its allowed rate of return. To the extent amounts calculated using this rate exceed the AFUDC calculated rate using the Federal Energy Regulatory Commission (FERC) formula, PSE capitalizes the excess as a deferred asset, crediting other income. The deferred asset is being amortized over the average useful life of PSE's non-project electric utility plant which is approximately 30 years.

The following table presents the AFUDC amounts:

	Year Ended December 31,		
(Dollars in Thousands)	2012	2011	2010
Equity AFUDC	$ 25,469	$ 32,431	$ 12,677
Washington Commission AFUDC	1,895	5,108	3,715
Total in other income	27,364	37,539	16,392
Debt AFUDC	22,216	29,949	14,157
Total AFUDC	$ 49,580	$ 67,488	$ 30,549

Revenue Recognition

Operating utility revenue is recognized when the basis of services is rendered, which includes estimated unbilled revenue, in accordance with ASC 605, "Revenue Recognition" (ASC 605). PSE's estimate of unbilled revenue is based on a calculation using meter readings from its automated meter reading (AMR) system. The estimate calculates unbilled usage at the end of each month as the difference between the customer meter readings on the last day of the month and the last customer meter readings billed. The unbilled usage is then priced at published rates for each schedule to estimate the unbilled revenues by customer.

Sales to other utilities are recognized in accordance with ASC 605 and ASC 815, "Derivatives and Hedging" (ASC 815). 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. Sales of RECs are deferred as a regulatory liability.

PSE collected Washington State excise taxes (which are a component of general retail customer rates) and municipal taxes totaling $244.2 million, $252.5 million and $231.1 million for 2012, 2011 and 2010, respectively. The Company reports the collection of such taxes on a gross basis in operating revenue and as expense in taxes other than income taxes in the accompanying consolidated statements of income.

Allowance for Doubtful Accounts

Allowance for doubtful accounts are provided for electric and natural gas customer accounts based upon a historical experience rate of write-offs of energy accounts receivable along with information on future economic outlook. The allowance account is adjusted monthly for this experience rate. The allowance account is maintained until either receipt of payment or the likelihood of collection is considered remote at which time the allowance account and corresponding receivable balance are written off.

The Company's allowance for doubtful accounts at December 31, 2012 and 2011 was $9.9 million and $8.5 million, respectively.

Self-Insurance

PSE currently has no insurance coverage for storm damage and recent environmental contamination occurring on PSE-owned property. PSE 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 qualifying storm damage costs that exceed $8.0 million which will be requested for collection in future rates. Additionally, costs may only be deferred if the outage meets the Institute of Electrical and Electronics Engineers (IEEE) outage criteria for system average interruption duration index.

Federal Income Taxes

For presentation in Puget Energy and PSE's separate financial statements, income taxes are allocated to the subsidiaries on the basis of separate company computations of tax, modified by allocating certain consolidated group limitations which are attributed to the separate company. Taxes payable or receivable are settled with Puget Holdings.

Natural Gas Off-System Sales and Capacity Release

PSE 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, PSE 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. PSE 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, PSE nets the sales revenue and associated cost of sales for these transactions in purchased natural gas.

Non-Core Gas Sales

As part of the Company's electric operations, PSE provides natural gas to its gas-fired generation facilities. The projected volume of natural gas for power is relative to the price of natural gas. Based on the market prices for natural gas, PSE may use the gas it has already purchased to generate power or PSE may sell the already purchased natural gas. The net proceeds from selling natural gas for power are accounted for in other electric operating revenue and are included in the PCA mechanism.

Production Tax Credit

Production Tax Credits (PTCs) represent federal income tax incentives available to taxpayers that generate energy from qualifying renewable sources. Prior to July 1, 2010, PSE passed the benefit of the PTCs to customers as the benefits were generated. After July 1, 2010, PSE records the benefit of the PTCs as a regulatory liability until such time as PSE utilizes the tax credit on its tax return. Once utilized, PSE will pass the benefit to customers.

Accounting for Derivatives

ASC 815 requires that all contracts considered to be derivative instruments be recorded on the balance sheet at their fair value unless the contracts qualify for an exception. PSE enters into derivative contracts to manage its energy resource portfolio and interest rate exposure including forward physical and financial contracts and swaps. Some of PSE's physical electric supply contracts qualify for the Normal Purchase Normal Sale (NPNS) exception to derivative accounting rules. PSE may enter into financial fixed contracts to economically hedge the variability of certain index-based contracts. Those contracts that do not meet the NPNS exception are marked-to-market to current earnings in the statements of income, subject to deferral under ASC 980, for energy related derivatives due to the PCA mechanism and PGA mechanism.

Puget Energy and PSE elected to de-designate all energy related derivative contracts previously recorded as cash flow hedges for the purpose of simplifying its financial reporting in 2009. The contracts that were de-designated related to physical electric supply contracts and natural gas swap contracts used to fix the price of natural gas for electric generation. For these contracts and for contracts initiated after such date, all mark-to-market adjustments are recognized through earnings. The amount previously recorded in accumulated other comprehensive income (OCI) is transferred to earnings in the same period or periods during which the hedged transaction affects earnings or sooner if management determines that the forecasted transaction is probable of not occurring. As a result, the Company will continue to experience the earnings impact of these reversals from OCI in future periods.

The Company may enter into swap instruments or other financial derivative instruments to manage the interest rate risk associated with its long-term debt financing and debt instruments. As of December 31, 2012, Puget Energy has interest rate swap contracts outstanding related to its long-term debt. For additional information, see Note 9 Accounting for Derivative Instruments and Hedging Activities.

Fair Value Measurements of Derivatives

ASC 820, "Fair Value Measurements and Disclosures" (ASC 820), defines fair value as 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 ASC 820, 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 as it believes that the approach is used by market participants for these types of assets and liabilities. 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. For additional information, see Note 10 Fair Value Measurements.

Debt Related Costs

Debt premiums, discounts, expenses and amounts received or incurred to settle hedges are amortized over the life of the related debt for the Company. 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 for PSE.

Statements of Cash Flows

The Company has refinancing transactions that do not result in an actual exchange of cash. For these transactions, the Company evaluates if the non-exchange of cash is for convenience purposes and if so, the Company considers the transaction as if it had constructively received and disbursed the cash and presents the transaction as gross on the financing section of the statements of cash flows.

PSE funds cash dividends to pay the shareholder of Puget Energy.

The following non-cash investing and financing activities have occurred at the Company:

- PSE incurred capital lease obligations of $33.2 million and $37.9 million for automatic meter reading modules and network for the years ended December 31, 2012 and 2011, respectively. PSE incurred no capital lease obligations for the year ended December 31, 2010.

Accumulated Other Comprehensive Income (Loss)

The following tables set forth the components of the Company's accumulated other comprehensive income (loss) at December 31:

Puget Energy	December 31,	
(Dollars in Thousands)	2012	2011
Net unrealized loss on energy derivative instruments	$ (742)	$ (1,113)
Net unrealized loss on interest rate swaps	(3,022)	(14,599)
Net unrealized loss and prior service cost on pension plans	(29,065)	(15,195)
Total Puget Energy, net of tax	$ (32,829)	$ (30,907)

Puget Sound Energy	December 31,	
(Dollars in Thousands)	2012	2011
Net unrealized loss on energy derivative instruments	$ (4,576)	$ (12,934)
Net unrealized loss on treasury interest rate swaps	(6,624)	(6,941)
Net unrealized loss and prior service cost on pension plans	(175,998)	(168,704)
Total PSE, net of tax	$ (187,198)	$ (188,579)

(2) New Accounting Pronouncements

Recent Accounting Pronouncements

Intangibles - Goodwill and Other. On January 1, 2012, Puget Energy adopted ASU 2011-08, Intangibles - Goodwill and Other (Topic 350): Testing Goodwill for Impairment(ASU 2011-08). ASU 2011-08 allows an entity the option to qualitatively assess whether it must perform the two-step goodwill impairment test in FASB ASC 350-20, Intangibles - Goodwill and Other. An entity has the option to qualitatively assess whether it is more likely than not (more than 50% likelihood) that the fair value of the reporting unit is less than its carrying amount. If an entity elects to perform the qualitative assessment and determines that it is more likely than not that the reporting unit's fair value is in excess of its carrying amount, no further evaluation is necessary. Otherwise, an entity would perform Step 1 of the goodwill impairment test in ASC 350-20.

ASU 2011-08 was effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011. ASU 2011-08 did not have a material impact on the financial reporting of Puget Energy.

In July 2012, the FASB issued ASU 2012-02 Intangibles - Goodwill and Other (Topic 350): Testing Indefinite-Lived Intangible Assets for Impairment (ASU 2012-02). ASU 2012-02 is effective for annual and interim impairment tests performed for fiscal years beginning after September 15, 2012 and early adoption is permitted. ASU 2012-02 allows an entity the option to first qualitatively assess whether it is more likely than not (more than 50% likelihood) that the asset is impaired. If an entity elects to perform the qualitative assessment and determines that it is more likely than not that the indefinite-lived intangible asset's fair value is in excess of its carrying amount, no further evaluation is necessary. Otherwise, an entity would perform the quantitative impairment test in accordance with ASC 350-30. ASU 2012-02 will not be adopted early and will not have a material impact on the financial reporting of Puget Energy.

Comprehensive Income. On January 1, 2012, the Company adopted ASU 2011-05, Comprehensive Income (Topic 220): Presentation of Comprehensive Income (ASU 2011-05). ASU 2011-05 allows an entity the option to present the total of comprehensive income, the components of net income, and the components of OCI either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In both choices, an entity is required to present each component of net income along with total net income, each component of OCI along with a total for OCI, and a total amount for comprehensive income. ASU 2011-05 eliminates the option to present the components of OCI as part of the statement of changes in stockholders' equity. The ASU also requires the presentation of reclassification adjustments for items that are reclassified from OCI to net income on the financial statements. However, the FASB has deferred this requirement. The amendments to the ASC in the ASU do not change the items that must be reported in OCI or when an item of OCI must be reclassified to net income.

ASU 2011-05 should be applied retrospectively, and was effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. Prior to the effective date of the ASU, the Company had already complied with the presentation requirement, as the Company presents the total of comprehensive income, the components of net income, and the components of OCI in two separate statements. Therefore, ASU 2011-05 did not have an impact on the Company's consolidated financial statements.

Fair Value Measurement. On January 1, 2012, the Company adopted ASU 2011-04, Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in GAAP and International Financial Reporting Standards (IFRS) (ASU 2011-04). ASU 2011-04 represents the converged guidance of the FASB and the International Accounting Standards Board on fair value measurement. Many of the amendments to ASC 820, "Fair Value Measurements and Disclosures" (ASC 820), eliminate unnecessary wording differences between IFRS and GAAP. ASU 2011-04 expands ASC 820's existing disclosure requirements for fair value measurements categorized in Level 3 by requiring (1) a quantitative disclosure of the unobservable inputs and assumptions used in the measurement, (2) a description of the valuation processes in place, and (3) a narrative description of the sensitivity of the fair value to changes in unobservable inputs and the interrelationships between those inputs. In addition, ASU 2011-04 requires the Company to indicate the level in the fair value hierarchy of items that are not recorded at fair value but whose fair value must be disclosed.

Other amendments to ASC 820 include clarifying the highest and best use and valuation premise for nonfinancial assets, net risk position fair value measurement option for financial assets and liabilities with offsetting positions in market risks or counterparty credit risk, premiums and discounts in fair value measurement, and fair value of an instrument classified in a reporting entity's shareholders' equity.

ASU 2011-04 was effective for interim and annual periods beginning after December 15, 2011. Adoption of ASU 2011-04 did not have a significant impact on the Company's consolidated financial statements.

Balance Sheet. In December 2011, the FASB issued ASU 2011-11- Balance Sheet (Topic 210) (ASU 2011-11). ASU 2011-11 is effective for annual reporting periods beginning on or after January 1, 2013. ASU 2011-11, as amended by ASU 2013-01, Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities, enhances disclosure requirements about the nature of an entity's right to offset and related arrangements associated with its derivative instruments. ASU 2011-11 requires the disclosure of the gross amounts subject to rights of set-off, amounts offset in accordance with the accounting standards followed, and the related net exposure.

ASU 2011-11, as amended, is effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013. Retrospective application of the disclosures is required for all periods presented within the financial statements. These disclosure requirements are the only impact on the Company's consolidated financial statements.

(3) Regulation and Rates

Regulatory Assets and Liabilities

ASC 980 requires PSE to defer certain costs that would otherwise be charged to expense, if it were probable that future rates will permit recovery of such costs. It similarly requires deferral of revenues or gains and losses that are expected to be returned to customers in the future.

Below is a chart with the allowed return on the net regulatory assets and liabilities and the associated time periods:

Period	Rate of Return	After-Tax Return
May 14, 2012 - present	7.80%	6.71%
April 8, 2010 - May 13, 2012	8.10	6.90
November 1, 2008 - April 7, 2010	8.25	7.00

The net regulatory assets and liabilities at December 31, 2012 and 2011 included the following:

Puget Sound Energy (Dollars in Thousands)	Remaining Amortization Period	December 31, 2012	December 31, 2011
PGA deferral of unrealized losses on derivative instruments	(a)	$ 95,953	$ 200,893
Chelan PUD contract initiation	18.8 years	133,492	140,580
Storm damage costs electric	1 to 6 years (a)	131,904	87,303
Environmental remediation	(a)	66,402	65,167
Baker Dam licensing operating and maintenance costs	46 years	57,644	60,631
Deferred income taxes	(a)	119,279	61,344
Deferred Washington Commission AFUDC	Varies up to 26 years	55,896	56,315
Energy conservation costs	1 to 2 years	26,940	35,111
Unamortized loss on reacquired debt	1 to 38.8 years	31,399	33,023
White River relicensing and other costs	(a)	29,654	30,993
Mint Farm ownership and operating costs	12.3 years	24,321	26,582
Investment in Bonneville Exchange power contract	4.5 years	15,870	19,396
PCA mechanism	(a)	3,773	6,818
Ferndale	(a)	1,789	—
Lower Snake River	3.3 to 24.3 years	126,887	—
Various other regulatory assets	Varies	15,020	21,347
Total PSE regulatory assets		$ 936,223	$ 845,503
Cost of removal	(b)	$ (239,243)	$ (219,087)
Production tax credits	(c)	(93,618)	(93,618)
PGA payable	1 year	(32,587)	(25,940)
Summit purchase option buy-out	7.8 years	(12,338)	(13,913)
Deferred credit on gas pipeline capacity	Varies up to 5.8 years	(6,213)	(7,987)
Renewable energy credits	(a)	(11,341)	(2,780)
Treasury grants	7 to 10 years	(225,573)	(23,179)
Various other regulatory liabilities	Up to 4 years	(7,998)	(3,521)
Total PSE regulatory liabilities		$ (628,911)	$ (390,025)
PSE net regulatory assets and liabilities		$ 307,312	$ 455,478

(a) *Amortization periods vary depending on timing of underlying transactions or awaiting regulatory approval in a future Washington Commission rate proceeding.*

(b) *The balance is dependent upon the cost of removal of underlying assets and the life of utility plant.*

(c) *Amortization will begin once PTCs are utilized by PSE on its tax return.*

Puget Energy	Remaining Amortization	December 31,	
(Dollars in Thousands)	Period	2012	2011
Total PSE regulatory assets	(a)	$ 936,223	$ 845,503
Puget Energy acquisition adjustments:			
Regulatory assets related to power contracts	1 to 24 years	37,655	46,202
Service provider contracts	1 year	2,614	5,751
Various other regulatory assets	1 year	565	1,449
Total Puget Energy regulatory assets		$ 977,057	$ 898,905
Total PSE regulatory liabilities	(a)	$ (628,911)	$ (390,025)
Puget Energy acquisition adjustments:			
Regulatory liabilities related to power contracts	1 to 39 years	(507,009)	(582,836)
Various other regulatory liabilities	Varies	(4,373)	(5,318)
Total Puget Energy regulatory liabilities		$ (1,140,293)	$ (978,179)
Puget Energy net regulatory asset and liabilities		$ (163,236)	$ (79,274)

(a) *Puget Energy's regulatory assets and liabilities include purchase accounting adjustments under ASC 805 as a result of the merger.*

If the Company determines that it no longer meets the criteria for continued application of ASC 980, the Company would be required to write off its regulatory assets and liabilities related to those operations not meeting ASC 980 requirements. Discontinuation of ASC 980 could have a material impact on the Company's financial statements.

In accordance with guidance provided by ASC 410, "Asset Retirement and Environmental Obligations," PSE reclassified from accumulated depreciation to a regulatory liability $239.2 million and $219.1 million in 2012 and 2011, respectively, for the cost of removal of utility plant. These amounts are collected from PSE's customers through depreciation rates.

Electric Regulation and Rates

Storm Damage Deferral Accounting

The Washington Commission issued a general rate case order that defined deferrable catastrophic/extraordinary losses and provided that costs in excess of $8.0 million annually may be deferred for qualifying storm damage costs that meet the modified IEEE outage criteria for system average interruption duration index. PSE's storm accounting allows deferral of certain storm damage costs. In 2012 and 2011, PSE incurred $71.5 million and $4.6 million, respectively, in storm-related electric transmission and distribution system restoration costs, of which $60.4 million was deferred in 2012 and no amount was deferred in 2011.

Electric General Rate Case

On May 20, 2010, PSE filed an accounting petition requesting that the Washington Commission approve: (1) the creation of a regulatory asset account for the prepayments made to the Bonneville Power Administration (BPA) associated with network upgrades to the Central Ferry substation related to the Lower Snake River wind project; (2) the monthly accrual of carrying charges on that regulatory asset at PSE's approved net of tax rate of return; and (3) the ability to provide customers the BPA interest received through a reduction to transmission expense.

On May 7, 2012, the Washington Commission issued its order in PSE's electric general rate case filed in June 2011, approving a general rate increase for electric customers of $63.3 million or 3.2% annually. The rate increases for electric customers became effective May 14, 2012. In its order, the Washington Commission approved a weighted cost of capital of 7.8% and a capital structure that included 48.0% common equity with a return on equity of 9.8%. PSE's requested treatment of the prepayments made to BPA, filed in May 2010, was approved in the order. The final order rejected PSE's proposed conservation savings adjustment. Finally, a new rate rider for Renewable Energy Credits ("RECs") was proposed by settlement of Electric parties and approved by the Washington Commission in the final order.

On April 2, 2010, the Washington Commission issued its order in PSE's consolidated electric rate case filed in May 2009 which approved a general rate increase for electric customers of 3.7% annually, or $74.1 million, effective April 8, 2010. In its order, the Washington Commission approved a weighted cost of capital of 8.1% and a capital structure that included 46.0% common equity with an after-tax return on equity of 10.1%.

The following table sets forth electric rate adjustments approved by the Washington Commission and the corresponding impact on PSE's revenue based on the effective dates:

Type of Rate Adjustment	Effective Date	Average Percentage Increase (Decrease) in Rates	Increase (Decrease) in Revenue (Dollars in Millions)
Electric General Rate Case	April 8, 2010, Annual	3.7%	$74.1
Renewable Energy Credit Proceeds	November 1, 2010 - March 31, 2011	(2.9)	(27.7)
Electric General Rate Case	May 14, 2012, Annual	3.2	63.3

Power Cost Only Rate Case

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 has used an expedited six-month PCORC decision timeline rather than the statutory 11-month timeline for a general rate case.

Accounting Orders and Petitions

On May 21, 2008, PSE filed an accounting petition for a Washington Commission order that authorizes 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). The payment was expensed pending resolution of the accounting petition. In the April 2, 2010 general rate case order, the Washington Commission allowed recovery of $8.4 million in PSE's operating costs, which represents the amount of the settlement, net of insurance proceeds.

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. In the April 2, 2010 general rate case order, the Washington Commission denied recovery of the interest due to the IRS. PSE expensed the interest deferral of $6.9 million in April 2010.

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. In the April 2, 2010 general rate case order, the Washington Commission approved the deferral of $7.5 million and amortization as proposed.

On April 17, 2009, the Washington Commission issued an order approving and adopting a settlement agreement that authorized PSE to defer certain ownership and operating costs related to its purchase of the Mint Farm Electric Generating Station (Mint Farm) that were incurred prior to PSE recovering such costs in electric customer rates. Under Washington state law, a jurisdictional electric utility may defer the costs associated with purchasing and operating a natural gas plant that complies with the GHG emissions performance standard until the plant is included in rates or for two years from the date of purchase, whichever occurs sooner. In the April 2, 2010 general rate case order, the Washington Commission approved the prudence of the Mint Farm acquisition and recovery of the deferred costs from the plant's in-service date to the date of the order. The deferred costs are to be amortized over 15 years. As of December 31, 2012, the balance of the regulatory asset, net of amortization was $24.3 million .

The Washington Commission issued an order in 2010 relating to how REC proceeds should be handled for regulatory accounting and ratemaking purposes. The order required REC proceeds to be recorded as regulatory liabilities and that amounts recorded would accrue interest at the Company's approved after-tax rate of return. In its petition, PSE had sought approval for the use of $21.1 million of REC proceeds to be used as an offset against its California wholesale energy sales regulatory asset. In response to the order, PSE adjusted the carrying value of its regulatory asset in the second quarter of 2011 by $17.8 million (from $21.1 million to $3.3 million), with the $3.3 million then offset against the Company's RECs regulatory liability. The Company's California wholesale energy sales regulatory asset represented unpaid bills for power sold into the markets maintained by the California Independent System Operator during the 2000-2001 California Energy Crisis, the claims of which were settled along with all counterclaims against PSE in a settlement agreement approved by the FERC on July 1, 2009. The Washington Commission ordered that parties provide recommended methods for passing back the remaining deferred proceeds. On October 26, 2010, the Commission approved a joint proposal that allowed a portion of the REC proceeds received by PSE to offset the PTCs that had been passed through to customers but have not been used by PSE on its tax return, and after completion of the PTC offset, the

Commission allowed PSE to offset the REC liability against rate base and amortize the balance of RECs at the beginning of a given rate year over five years as a credit to cost of service. On May 7, 2012, a new rate rider for RECs was approved by the Commission in the final order in PSE's general rate case. The new rate rider replaced prospectively what was required pursuant to the Commission's orders in 2010.

On October 25, 2012 PSE filed a petition for an order authorizing PSE to implement electric and natural gas decoupling mechanisms and to record accounting entries associated with the mechanism. This is currently pending before the Commission.

Production Tax Credit / Renewable Energy Credit

PSE has a tariff which passes the benefits of the PTCs to customers. The tariff is not subject to the sharing bands in the PCA. Prior to July 1, 2010, PSE would adjust the PTC tariff annually based on differences between the PTC benefits provided to the customers and the PTCs actually generated. Since PSE was providing the benefit of the PTCs to customers prior to utilizing the PTCs on its tax returns, the Company would be reimbursed for its carrying costs.

Effective July 1, 2010, the Washington Commission approved a change in PSE’s PTC tariff. PSE had not been able to utilize PTCs on its tax return since 2007 due to insufficient taxable income caused primarily by bonus tax depreciation. The Washington Commission approved the suspension of the tariff, effective July 1, 2010. This resulted in an overall increase in PSE’s electric rates of 1.7%; however, this did not result in an increase in earnings as the benefit of PTCs pass-through to customers without impact to earnings. The tariff was renamed the Federal Incentive Tracker as it was also expanded to cover additional federal incentives.

On September 22, 2010, a joint proposal and accounting petition was filed with the Washington Commission by PSE, Washington Commission Staff and Industrial Customers of Northwest Utilities which addressed how to recover PTCs provided to customers that have not been utilized and addresses REC proceeds to be returned to customers. On October 26, 2010, the Washington Commission issued an order allowing PSE to recover PTCs provided to customers that have not been utilized and addressing the pass back of REC proceeds to customers. The order allows the Company to credit customers for REC revenue received and deferred through November 2009. This credit was set to reduce rates by $27.7 million, or 2.9%, over five months beginning November 2010 through March 2011. RECs received after November 2009 would be retained by PSE and would be used to recapture the benefit of PTCs previously provided to customers. Finally, the order provides that PSE will pass-through to customers the benefit of the PTCs following the year in which they are utilized on PSE's tax return.

PCA Mechanism

In 2002, the Washington Commission approved 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 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.

The graduated scale is as follows:

Annual Power Cost Variability	Customers’ Share	Company’s Share
+/- $20 million	0%	100%
+/- $20 million - $40 million	50%	50%
+/- $40 million - $120 million	90%	10%
+/- $120 + million	95%	5%

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 natural gas and transportation 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.

Treasury Grant

Section 1603 of the American Recovery and Reinvestment Tax Act of 2009 (Section 1603) authorizes the United States Department of the Treasury (U.S. Treasury) to make grants (Treasury Grants) to taxpayers who place specified energy property in service provided certain conditions are met. Section 1603 precludes a recipient from claiming PTCs on property for which a grant is claimed.

The Wild Horse wind project (Wild Horse) expansion facility was placed into service on November 9, 2009. The capacity of the Wild Horse facility was expanded from 229 megawatts (MW) to 273 MW through the addition of wind turbines. In February 2010, the U.S. Treasury approved a Treasury Grant of $28.7 million. The 343 MW Lower Snake River facility was placed into service on February 29, 2012. In December 2012, the U.S. Treasury approved a Treasury Grant of $205.3 million.

On December 30, 2010, the Washington Commission approved revisions to PSE's Federal Incentive Tracker tariff, effective January 1, 2011. The rate schedule passed-through $5.5 million of the $28.7 million Wild Horse Expansion Treasury Grant in 2011. The order authorized PSE to pass back one-tenth of the Treasury Grant on an annual basis and included 23 months of Treasury Grant amortization to customers from February 2010 through December 2011, which represented the month the Treasury Grant funds were received through the end of the period over which the rates will be set. This represents an overall average rate reduction of 0.3%, with no impact to net income.

On February 29, 2012, PSE filed proposed tariff revisions, with stated effective dates of April 1, 2012, and subsequently revised by filing on March 29, 2012 with stated effective dates of June 1, 2012, to pass-through $2.4 million in interest on the unamortized balance of the Wild Horse Expansion Treasury Grant. On June 26, 2012, the Washington Commission approved PSE's methods and calculations and new rates became effective on July 3, 2012.

On January 31, 2013, the Washington Commission approved a rate change to the PSE's Federal Incentive Tracker tariff, effective February 1, 2013, which incorporated the effects of the Treasury Grant related to the Lower Snake River wind generation project and keeping the ten year amortization period and inclusion of interest on the unamortized balance of the grants. The rate change will pass through 11 months of amortization for both grants to eligible customers over 11 months beginning February 1, 2013. Of the total credit, $34.6 million represents the pass-back of grant amortization and $23.8 million represents the pass through of interest. This represents an overall average rate decrease of 2.76%.

Gas Regulation and Rates

Gas General Rate Cases and Other Filings Affecting Rates

On October 31, 2012, the Washington Commission suspended PSE's PGA natural gas tariff filing but allowed the rates to go into effect on November 1, 2012 on a temporary basis subject to revision. The rates resulted in a decrease to the rates charged to customers under the PGA. The estimated revenue impact of the approved change if allowed on a permanent basis is a decrease of $77.0 million, or 7.7% annually. The rate adjustment has no impact on PSE's net income.

On October 25, 2012 PSE filed a petition for an order authorizing PSE to implement electric and natural gas decoupling mechanisms and to record accounting entries associated with the mechanism. This is currently pending before the Commission.

On June 1, 2012, PSE filed with the Washington Commission a petition seeking an Accounting Order authorizing PSE to change the existing natural gas conservation tracker mechanism into a rider mechanism to be consistent with the electric conservation program recovery. The accounting petition requested the ability to recover the costs associated with the Company's current gas conservation programs via transfers from amounts deferred for the over-recovery of commodity costs in the Company's PGA mechanism. The Commission granted PSE's accounting petition on June 28, 2012. The approved accounting petition resulted in an increase to gas conservation revenues of $6.9 million and an increase to conservation amortization expense of 6.6 million.

On October 27, 2011, the Washington Commission approved PSE's PGA natural gas tariff filing effective November 1, 2011, to decrease the rates charged to customers under the PGA. The estimated revenue impact of the approved charge is a decrease of $43.5 million, or 4.3% annually. The rate adjustment has no impact on PSE's net income.

On June 13, 2011, PSE filed a general rate increase with the Washington Commission which proposed an increase in natural gas rates of $31.9 million or 3.0%, to be effective May 2012. PSE requested a weighted cost of capital of 8.42%, or 7.29% after-tax, and a capital structure of 48.0% in common equity with a return on equity of 10.8%. The filing also proposes a conservation savings adjustment mechanism related to energy efficiency services for business and residential customers. On January 17, 2012, PSE filed rebuttal testimony which included a reduction to the requested natural gas rate increase to $28.6 million. The $3.3 million reduction was primarily due to a change to the weighted cost of capital to 8.26%, or 7.17% after-tax, which included a change to the return on equity to 10.75%.

On May 7, 2012, the Washington Commission issued its order in PSE's natural gas general rate case filed in June 2011, approving a general rate increase for natural gas customers of $13.4 million or 1.3% annually. The rate increases for natural gas customers became effective May 14, 2012. In its order, the Washington Commission approved a weighted cost of capital of 7.8% and a capital structure that included 48.0% common equity with a return on equity of 9.8%.

On April 26, 2011, PSE filed a new tariff for a Natural Gas Pipeline Integrity Program. This program is intended to enhance pipeline safety by providing for the timely recovery of the Company's cost to replace certain natural gas system infrastructure that would emphasize system reliability, integrity and safety which would increase natural gas revenue by $1.9 million or 0.2%. In its final order the Washington Commission rejected PSE's tariff filing, but initiated an investigation to determine if more needs to be done for replacement requirements and cost recovery methods in order to decrease the risks associated with older plastic and other identified pipe. On November 28, 2012, the Washington Commission issued a Draft Statement of Commission Policy in the investigation. Comments on the Draft Policy Statement were filed on December 7, 2012. Under the Draft Policy Statement, PSE would provide bi-annual pipe replacement plans and would be allowed, beginning November 2013, expedited recovery of approved replacement costs made after October 2012 under the plans.

On March 14, 2011, the Washington Commission issued its order authorizing PSE to increase its natural gas general tariff rates by $19.0 million or 1.8% on an annual basis effective April 1, 2011.

On April 2, 2010, the Washington Commission issued its order, effective April 8, 2010, in PSE's natural gas general rate case filed in May 2009, approving a general rate increase of 0.8% annually or $10.1 million. In its order, the Washington Commission approved a weighted cost of capital of 8.1% and a capital structure that included 46.0% common equity with an after-tax return on equity of 10.1%.

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. In the April 2, 2010 general rate case order, the Washington Commission denied recovery of the interest due to the IRS. PSE expensed the interest deferral of $6.9 million in April 2010.

Purchased Gas Adjustment

On October 31, 2012, the Washington Commission suspended PSE's PGA natural gas tariff filing and instituted an investigation, but allowed the requested rate decrease under the PGA to go into effect on a temporary basis effective November 1, 2012, subject to revision. Commission Staff is required to report back to the Commission on the status of Staff's investigation no later than March 1, 2013, and that report shall include recommendations on the disposition of the tariff PSE filed or the need for further process to make the appropriate determination. The estimated revenue impact of the change is a decrease of $77.0 million, or 7.7% annually. The rate adjustment has no impact on PSE's net income.

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 net income is not affected by such variations. Changes in the PGA rates affect PSE's revenue, but do not impact net income as the changes to revenue are offset by increased or decreased purchased gas and gas transportation costs.

The following table sets forth natural gas rate adjustments that were approved by the Washington Commission and the corresponding impact to PSE's annual revenue based on the effective dates:

Type of Rate Adjustment	Effective Date	Average Percentage Increase (Decrease) in Rates	Annual Increase (Decrease) in Revenue (Dollars in Millions)
Purchased Gas Adjustment	November 1, 2012	(7.7)%	$(77.0)
Natural Gas General Rate Case	May 14, 2012	1.3%	13.4
Purchased Gas Adjustment	November 1, 2011	(4.3)%	(43.5)
Natural Gas General Tariff Adjustment	April 1, 2011	1.8%	19.0
Purchased Gas Adjustment	November 1, 2010 – October 31, 2011	1.9%	18.3
Natural Gas General Rate Case	April 8, 2010	0.8%	10.1
Purchased Gas Adjustment	October 1, 2009 – October 31, 2010	(17.1)%	(198.1)
Purchased Gas Adjustment	June 1, 2009	(1.8)%	(21.2)

Environmental Remediation

The Company is subject to environmental laws and regulations by the federal, state and local authorities and is required to undertake certain environmental investigative and remedial efforts as a result of these laws and regulations. The Company has been named by the Environmental Protection Agency (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 Washington Commission consolidated the gas and electric methodological approaches to remediation and deferred accounting in an order issued October 8, 2008. Per the guidance of ASC 450, "Contingencies," the Company reviews its estimated future obligations and adjusts loss reserves quarterly. Management believes it is probable and reasonably estimable that the impact of the potential outcomes of disputes with certain property owners and other potentially responsible parties will result in environmental remediation costs ranging from $37.6 million to $55.9 million for gas and from $8.6 million to $27.2 million for electric. The Company does not consider any amounts within those ranges as being a better estimate and has therefore accrued $37.6 million and $8.6 million for gas and electric, respectively. 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. For the year ended December 31, 2012, the Company incurred deferred electric and natural gas environmental costs of $10.9 million and $66.4 million, net of insurance proceeds, respectively.

(4) Dividend Payment Restrictions

The payment of dividends by PSE to Puget Energy is restricted by provisions of certain covenants applicable to long-term debt contained in PSE's electric and natural gas mortgage indentures. At December 31, 2012, approximately $551.7 million of unrestricted retained earnings was available for the payment of dividends under the most restrictive mortgage indenture covenant.

Beginning February 6, 2009, pursuant to the terms of the Washington Commission merger order, PSE may not declare or pay dividends if PSE's common equity ratio, calculated on a regulatory basis, is 44.0% or below except to the extent a lower equity ratio is ordered by the Washington Commission. Also, pursuant to the merger order, PSE may not declare or make any distribution unless on the date of distribution PSE's corporate credit/issuer rating is investment grade, or, if its credit ratings are below investment grade, PSE's ratio of Earnings Before Interest, Tax, Depreciation and Amortization (EBITDA) to interest expense for the most recently ended four fiscal quarter periods prior to such date is equal to or greater than 3 to one. The common equity ratio, calculated on a regulatory basis, was 48.0% at December 31, 2012 and the EBITDA to interest expense was 4.5 to one for the 12 months then ended.

PSE's ability to pay dividends is also limited by the terms of its credit facilities, pursuant to which PSE is not permitted to pay dividends during any Event of Default, or if the payment of dividends would result in an Event of Default (as defined in the facilities), such as failure to comply with certain financial covenants.

Puget Energy's ability to pay dividends is also limited by the merger order issued by the Washington Commission as well as by the terms of its credit facilities. Pursuant to the 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 four most recently ended fiscal quarters prior to such date is equal to or greater than 2 to one. At December 31, 2012, the EBITDA to interest expense was 2.7 to one for the 12 months then ended.

At December 31, 2012, the Company was in compliance with all applicable covenants, including those pertaining to the payment of dividends.

(5) Utility Plant

Utility Plant (Dollars In Thousands)	Estimated Useful Life (Years)	Puget Energy At December 31, 2012	Puget Energy At December 31, 2011	Puget Sound Energy At December 31, 2012	Puget Sound Energy At December 31, 2011
Electric, gas and common utility plant classified by prescribed accounts :					
Distribution plant	10-50	$ 4,276,123	$ 4,552,087	$ 5,993,055	$ 6,279,340
Production plant	25-125	2,480,135	1,618,196	3,464,528	2,616,855
Transmission plant	45-65	984,018	391,080	1,108,104	516,461
General plant	5-35	445,982	402,309	543,195	499,559
Intangible plant (including capitalized software)	3-50	181,884	152,025	181,596	187,948
Plant acquisition adjustment	7-30	242,659	211,807	282,624	251,772
Underground storage	25-60	27,331	27,139	40,987	40,815
Liquefied natural gas storage	25-45	12,622	12,622	14,492	14,492
Plant held for future use	NA	18,416	18,381	18,568	18,534
Recoverable Cushion Gas	NA	8,655	8,514	8,655	8,514
Plant not classified	NA	155,626	38,998	155,625	38,999
Capital leases, net of accumulated amortization [1]	1-5	24,629	32,208	24,629	32,207
Less: accumulated provision for depreciation		(1,067,424)	(674,783)	(4,045,402)	(3,714,913)
Subtotal		$ 7,790,656	$ 6,790,583	$ 7,790,656	$ 6,790,583
Construction work in progress	NA	766,035	1,282,462	766,035	1,282,462
Net utility plant		$ 8,556,691	$ 8,073,045	$ 8,556,691	$ 8,073,045

[1] *Accumulated amortization of capital leases at Puget Energy was $7.6 million in 2012 and $5.7 million in 2011. Accumulated amortization of capital leases at PSE was $7.6 million in 2012 and $5.7 million in 2011.*

In 2012, the Company acquired a power plant and related assets which resulted in an increase of approximately $90.0 million in assets. PSE recorded the plant assets at original cost and accumulated depreciation with an acquisition adjustment in accordance with FERC rules.

On February 4, 2013, the Company signed an agreement that allows a sale of electric infrastructure and a transition of electrical service to Jefferson County Public Utility District. The Company expects the sale to occur during the first half of 2013 for a price that exceeds the carrying value of the assets of $47.4 million as of December 31, 2012.

Jointly owned generating plant service costs are included in utility plant service cost. The following table indicates the Company's percentage ownership and the extent of the Company's investment in jointly owned generating plants in service at December 31, 2012. These amounts are also included in the Utility Plant table above.

Jointly Owned Generating Plants (Dollars in Thousands)	Energy Source (Fuel)	Company's Ownership Share	Puget Energy's Share: Plant in Service at Cost	Puget Energy's Share: Accumulated Depreciation	Puget Sound Energy's Share: Plant in Service at Cost	Puget Sound Energy's Share: Accumulated Depreciation
Colstrip Units 1 & 2	Coal	50%	$ 148,075	$ (6,152)	$ 284,692	$ (142,768)
Colstrip Units 3 & 4	Coal	25%	217,899	(22,459)	496,267	(300,827)
Colstrip Units 1 – 4 Common Facilities [1]	Coal	various	83	(14)	251	(182)
Frederickson 1	Gas	49.85%	61,779	(2,030)	70,712	(10,964)

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

The Company recognized new AROs of $7.7 million and $0.4 million in 2012 and 2011, respectively.

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

	At December 31,	
(Dollars in Thousands)	2012	2011
Asset retirement obligation at beginning of period	$ 26,540	$ 25,416
New asset retirement obligation recognized in the period	7,737	350
Liability settled in the period	(2,960)	(1,722)
Revisions in estimated cash flows	12,632	1,154
Accretion expense	1,547	1,342
Asset retirement obligation at end of period	$ 45,496	$ 26,540

The Company has identified the following obligations, as defined by ASC 410, "Asset Retirement and Environmental Obligations," which were not recognized at December 31, 2012 and 2011:

- a legal obligation under Federal Dangerous Waste Regulations to dispose of asbestos-containing material in facilities that are not scheduled for remodeling, demolition or sales. The disposal cost related to these facilities could not be measured since the retirement date is indeterminable; therefore, the liability cannot be reasonably estimated;
- 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;
- 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;
- a legal obligation under Washington state environmental laws to remove and properly dispose of certain under and above ground fuel storage 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;
- a potential legal obligation may arise upon the expiration of an existing FERC hydropower license if FERC orders the project to be decommissioned, although PSE contends that FERC does not have such authority. Given the value of ongoing generation, flood control and other benefits provided by these projects, PSE believes that the potential for decommissioning is remote and cannot be reasonably estimated;

(6) Long-Term Debt

Puget Sound Energy
(Dollars in Thousands)
First Mortgage Bonds, Pollution Control Bonds , Senior Notes and Junior Subordinated Notes

		At December 31,				At December 31,	
Series	Due	2012	2011	Series	Due	2012	2011
6.830%	2013	$ 3,000	$ 3,000	5.000% [1]	2031	$ 138,460	$ 138,460
6.900%	2013	10,000	10,000	5.100% [1]	2031	23,400	23,400
5.197%	2015	150,000	150,000	5.483%	2035	250,000	250,000
7.350%	2015	10,000	10,000	6.724%	2036	250,000	250,000
7.360%	2015	2,000	2,000	6.274%	2037	300,000	300,000
6.750%	2016	250,000	250,000	5.757%	2039	350,000	350,000
5.500% [2]	2017	2,412	—	5.764%	2040	250,000	250,000
6.740%	2018	200,000	200,000	5.795%	2040	325,000	325,000
7.150%	2025	15,000	15,000	4.434%	2041	250,000	250,000
7.200%	2025	2,000	2,000	5.638%	2041	300,000	300,000
7.020%	2027	300,000	300,000	4.700%	2051	45,000	45,000
7.000%	2029	100,000	100,000	6.974% [3]	2067	250,000	250,000
Total PSE long-term debt						$ 3,776,272	$ 3,773,860
Unamortized discount on senior notes						(14)	(15)
Net PSE long-term debt						$ 3,776,258	$ 3,773,845

1 *Pollution Control Bonds*
2 *Puget Western, Inc., a wholly owned subsidiary of PSE, Promissory Note*
3 *Junior Subordinated Notes*

Puget Energy		At December 31,	
(Dollars in Thousands)	Due	2012	2011
PSE long-term debt	Various	$ 3,776,258	$ 3,773,845
Fair value adjustment of PSE long-term debt		(264,017)	(276,322)
Term-loan	2014	—	298,000
Capital expenditures facility	2014	—	545,000
Senior secured credit facility	2017	434,000	—
6.500% senior secured note	2020	450,000	450,000
6.000% senior secured note	2021	500,000	500,000
5.625% senior secured note	2022	450,000	—
Original discount on Puget Energy term-loan and capital expenditures facility	N/A	—	(13,144)
Unamortized discount on senior secured note	N/A	(41)	(12)
Total Puget Energy long-term debt		$ 5,346,200	$ 5,277,367

Puget Sound Energy Long-Term Debt

PSE has in effect a shelf registration statement under which it may issue, from time to time, senior notes secured by first mortgage bonds. The Company remains subject to the restrictions of PSE's indentures and credit agreements on the amount of first mortgage bonds that PSE may issue.

On November 22, 2011, PSE issued $45.0 million of senior notes secured by first mortgage bonds. The notes have a term of 40 years and an interest rate of 4.700%. Net proceeds from the offering were used to repay a $25.0 million PSE bond maturing in 2020, with an interest rate of 9.570%

On November 16, 2011, PSE issued $250.0 million of senior notes secured by first mortgage bonds. The notes have a term of 30 years and an interest rate of 4.434%. Net proceeds from the offering were used to repay short-term indebtedness under PSE's capital expenditure credit facility.

On March 25, 2011, PSE issued $300.0 million of senior notes secured by first mortgage bonds. The notes have a term of 30-years and an interest rate of 5.638%. Net proceeds from the note offering were used by PSE to repay short-term debt outstanding under its capital expenditures credit facility, which debt was incurred to fund utility capital expenditures and replenish cash used to repay the February 2011 maturity of $260.0 million of medium-term notes with a 7.69% interest rate.

Substantially all utility properties owned by PSE 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 exceed certain minimums as defined in the indentures. At December 31, 2012, the earnings available for interest exceeded the required amount.

Puget Sound Energy Pollution Control Bonds

PSE has two series of Pollution Control Bonds outstanding. Amounts outstanding were borrowed from the City of Forsyth, Montana who 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.

Puget Energy Long-Term Debt

On June 15, 2012, Puget Energy issued $450.0 million of senior secured notes. Proceeds from the note offering were used to pay down $425.0 million of the revolving $859.0 million senior secured credit facility balance resulting in an outstanding balance of $434.0 million as of December 31, 2012.

On June 3, 2011, Puget Energy issued $500.0 million of senior secured notes. The notes are secured by an interest in substantially all of Puget Energy's assets, which consists mainly of all the issued and outstanding stock of PSE and the stock of Puget Energy held by Puget Equico LLC (Puget Equico). The notes mature on September 1, 2021 and have an interest rate of 6.0%. Net proceeds from the note offering were used by Puget Energy to repay $484.0 million of its 5-year term-loans and $9.9 million to unwind three outstanding interest rate swaps.

At the time of the merger in February 2009, Puget Energy entered into a $1.225 billion 5-year term-loan and a $1.0 billion five-year capital expenditure credit facility for funding capital expenditures. On February 10, 2012, Puget Energy entered into a $1.0 billion five-year revolving senior secured credit facility. As a revolving facility, amounts borrowed may be repaid without a reduction in the size of the facility. Initial borrowings under this facility were used to repay debt outstanding under the term loan and capital expenditure credit facility and those agreements were terminated.

The Puget Energy revolving senior secured credit facility contains usual and customary affirmative and negative covenants. The agreement also contains two financial covenants based on the following ratios: Group Funds From Operations (FFO) Coverage Ratio and Maximum Leverage Ratio, as defined in the agreement governing the senior secured credit facility.

Long-Term Debt Maturities

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

(Dollars in Thousands)	2013	2014	2015	2016	2017	Thereafter	Total
Maturities of:							
PSE long-term debt	$ 13,000	$ —	$ 162,000	$ 250,000	$ 2,412	$ 3,348,860	$ 3,776,272
Puget Energy long-term debt	—	—	—	—	434,000	1,400,000	1,834,000
Puget Energy long-term debt	$ 13,000	$ —	$ 162,000	$ 250,000	$ 436,412	$ 4,748,860	$ 5,610,272

Financial Covenants

Puget Energy's credit facility contains financial covenants related to group FFO coverage and maximum leverage. PSE's credit facilities contain financial covenants related to cash flow interest coverage, cash flow to net debt outstanding and debt service coverage, each as specified in the facilities. As of December 31, 2012, the Company is in compliance with its long-term debt financial covenants.

(7) Liquidity Facilities and Other Financing Arrangements

As of December 31, 2012 and 2011, PSE had $181.0 million and $25.0 million in short-term debt outstanding, respectively, exclusive of the demand promissory note with Puget Energy. Outside of the consolidation of PSE's short-term debt, Puget Energy had no short-term debt outstanding in either year as borrowings under its credit facilities are classified as long-term. PSE's weighted-average interest rate on short-term debt, including borrowing rate, commitment fees and the amortization of debt issuance costs, during 2012 and 2011 was 6.49% and 4.39%, respectively. As of December 31, 2012, PSE and Puget Energy had several committed credit facilities that are described below.

Puget Sound Energy Credit Facilities

At December 31, 2012, PSE maintained three committed unsecured revolving credit facilities that provided, in the aggregate, $1.15 billion in short-term borrowing capability and which matured concurrently in February 2014. These facilities included 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.The credit agreements allowed PSE to borrow at the bank's prime rate or to make floating rate advances at the LIBOR plus a spread that is based upon PSE's credit rating. The working capital facility, as amended, included a swing line feature allowing same day availability on borrowings up to $50.0 million. The $400.0 million working capital facility and $350.0 million credit agreement to support energy hedging allowed for issuing standby letters of credit. PSE paid a commitment fee on the unused portion of the credit facilities. The spreads and the commitment fee depended on PSE's credit ratings. As of December 31, 2012, the spread to the London Interbank Offered Rate (LIBOR) was 0.85% and the commitment fee was 0.26%. The $400.0 million working capital facility also served as a backstop for PSE's commercial paper program. PSE certifies its compliance with such covenants to participating banks each quarter. As of December 31, 2012, PSE maintained its investment grade ratings and was in compliance with all applicable covenants under the three credit facilities. As of December 31, 2012, no amounts were drawn and outstanding under PSE's $400.0 million working capital facility. Two letters of credit totaling $9.6 million in support of contracts were outstanding under the facility, and $181.0 million was outstanding under the commercial paper program. The $400.0 million capital expenditure facility had no amounts drawn and outstanding. No amounts were drawn or outstanding (including letters of credit) under PSE's $350.0 million facility supporting energy hedging. Outside of the credit agreements, PSE had a $4.9 million letter of credit in support of a long-term transmission contract.

On February 4, 2013, PSE entered into two new credit facilities and terminated its previous three credit facilities. The new credit facilities provide, in aggregate, $1.0 billion of short-term liquidity needs. These facilities consist of a $650.0 million revolving liquidity facility (which includes a liquidity letter of credit facility and a swingline facility) to be used for general corporate purposes, including a backstop to the Company's commercial paper program and a $350.0 million revolving energy hedging facility (which includes an energy hedging letter of credit facility). The $650.0 million liquidity facility includes a swingline feature allowing same day availability on borrowings up to $75.0 million. The new credit facilities also have an accordion feature that, upon the banks' approval, would increase the total size of these facilities to $1.5 billion.

The credit agreements for these two replacement credit facilities contain similar terms and conditions, are syndicated among numerous lenders and mature in February 2018. The credit agreements contain usual and customary affirmative and negative covenants, that, among other things, place limitations on PSE's ability to incur additional indebtedness and liens, issue equity, pay dividends, transact with affiliates and make asset dispositions and investments. The credit agreements also contain a financial covenant of total debt to total capitalization of 65% or less. The credit agreements provide PSE with the ability to borrow at different interest rate options. The credit agreements allow PSE to borrow at the bank's prime rate or to make floating rate advances at the LIBOR plus a spread that is based upon PSE's credit rating. PSE must pay a commitment fee on the unused portion of the credit facilities. The spreads and the commitment fee depend on PSE's credit ratings. As of the date of this report, the spread to the LIBOR is 1.50% and the commitment fee is 0.225%.

Demand Promissory Note. On June 1, 2006, PSE entered into a revolving credit facility with Puget Energy, in the form of a credit agreement and a Demand Promissory Note (Note) pursuant to which 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 lower of the weighted-average interest rates of PSE's outstanding commercial paper interest rate or PSE's senior unsecured revolving credit facility. Absent such borrowings, interest is charged at one-month LIBOR plus 0.25%. At December 31, 2012, the outstanding balance of the Note was $29.6 million. The outstanding balance and the related interest under the Note are eliminated by Puget Energy upon consolidation of PSE's financial statements.

Puget Energy Credit Facilities

On February 10, 2012, Puget Energy entered into a $1.0 billion five-year revolving senior secured credit facility. The senior secured credit facility provides Puget Energy the ability to borrow at different interest rate options and includes variable fee levels. Interest rates may be based on the prime rate or LIBOR, plus a spread based on Puget Energy's credit ratings. Puget Energy must pay a commitment fee on the unused portion of the facility. At December 31, 2012, $434.0 million was drawn and outstanding under the facility, the spread over LIBOR was 2.0% and the commitment fee was 0.375%. Puget Energy entered into interest rate swap contracts to manage the interest rate risk associated with the credit facility. As of December 31, 2012, Puget Energy was in compliance with all applicable covenants.

Concurrent with the closing of the new PSE credit facilities in February 2013, the Company reduced the size of Puget Energy's credit facility from $1.0 billion to $800.0 million. The Puget Energy revolving credit facility also has an accordion feature that, upon the banks' approval, would increase the size of the facility to $1.3 billion. All other terms and conditions of that facility remain unchanged.

(8) Leases

PSE leases buildings and assets under operating leases. Certain leases contain purchase options, renewal options and escalation provisions. Operating lease expense net of sublease receipts were:

(Dollars in Thousands) At December 31,	
2012	$ 29,661
2011	24,789
2010	22,493

Payments received for the subleases of properties were immaterial for each of the years ended 2012, 2011 and 2010.

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

(Dollars in Thousands) At December 31,	Operating	Capital
2013	$ 16,238	$ 8,160
2014	15,199	8,160
2015	15,257	8,160
2016	17,175	2,718
2017	17,064	—
Thereafter	81,944	—
Total minimum lease payments	$ 162,877	$ 27,198

(9) Accounting for Derivative Instruments and Hedging Activities

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

At the February 2009 merger date, Puget Energy recorded all derivative contracts at fair value as either assets or liabilities. Certain contracts meeting the criteria defined in ASC 815 were subsequently designated as NPNS or cash flow hedges. As PSE had no change in accounting for these contracts at the time of the merger, this resulted in a difference in the accounting for certain contracts between Puget Energy and PSE. The difference in the derivative unrealized gains/losses recorded through earnings between Puget Energy and PSE, caused by these contracts, will continue to occur through March 2015.

On July 1, 2009, Puget Energy and PSE elected to de-designate all energy related derivative contracts previously recorded as cash flow hedges for the purpose of simplifying its financial reporting. The contracts that were de-designated related to physical electric supply contracts and natural gas swap contracts used to fix the price of natural gas for electric generation. For these contracts and for contracts initiated after such date, all mark-to-market adjustments are recognized through earnings, unless the amounts qualify and are deferred as regulatory assets or liabilities. The amount previously recorded in accumulated OCI is transferred to earnings in the same period or periods during which the hedged transaction affects earnings or sooner if management determines that the forecasted transaction is probable of not occurring. As a result, the Company will continue to experience the earnings impact of these reversals from OCI in future periods through March 2015.

The Company manages its interest rate risk through the issuance of mostly fixed-rate debt with varied maturities. The Company utilizes internal cash from operations, borrowings under its commercial paper program, and its credit facilities to meet short-term funding needs. Short-term obligations are commonly refinanced with fixed-rate bonds or notes when needed and when interest rates are considered favorable. The Company may also enter into swap instruments or other financial hedge instruments to manage the interest rate risk associated with these debts. As of December 31, 2012, Puget Energy had two interest rate swap contracts outstanding and PSE did not have any outstanding interest rate swap instruments.

In February 2009, Puget Energy entered into a cash flow hedge using interest rate swaps to hedge the risk associated with one-month LIBOR floating rate debt. Subsequently, in order to satisfy a commitment the Company made to the Washington Commission and to mitigate interest rate risk, the Company refinanced a portion of the underlying debt hedged by the interest rate swaps in 2010, 2011, and again during 2012. In order to better align its existing swap notional with the reduced underlying debt balance, in 2012, the Company net settled $827.4 million of the interest rate swaps, thereby reducing the swap notional to $450.0 million. Additionally, the Company amended the remaining two interest rate swap agreements to extend the maturities to January 2017. As a result of refinancing in 2010, the Company de-designated the cash flow hedge accounting relationship between the debt and interest rate swaps. A portion of the outstanding interest rate swap derivative loss associated with the probable future interest payments occurring remains in OCI, and is amortized monthly as the payments occur. The portion of the outstanding interest rate swap derivative loss associated with interest payments on the debt where future payments become remote of occurring is reclassified from OCI into earnings.

The following tables present the fair value and locations of the Company's derivative instruments recorded on the balance sheets:

Derivatives Not Designated as Hedging Instruments

Puget Energy	December 31, 2012		December 31, 2011	
(Dollars in Thousands)	Assets [1]	Liabilities [2]	Assets [1]	Liabilities [2]
Interest rate swaps:				
Current	$ —	$ 6,571	$ —	$ 25,210
Long-term	—	14,953	—	27,199
Total interest rate swaps	$ —	$ 21,524	$ —	$ 52,409
Puget Energy and Puget Sound Energy				
Electric portfolio:				
Current	$ 3,418	$ 93,097	$ 5,212	$ 173,582
Long-term	6,139	38,096	5,508	90,752
Natural gas portfolio: [3]				
Current	3,451	77,851	1,435	128,297
Long-term	8,675	30,227	4,576	78,607
Total energy derivatives	$ 21,683	$ 239,271	$ 16,731	$ 471,238

1 *Balance sheet location: Unrealized gain on derivative instruments.*

2 *Balance sheet location: Unrealized loss on derivative instruments.*

3 *PSE had a net derivative liability and an offsetting regulatory asset of $96.0 million at December 31, 2012 and $200.9 million at December 31, 2011 related to contracts used to economically hedge the cost of physical gas purchased to serve natural gas customers. All fair value adjustments on derivatives relating to the natural gas business have been reclassified to a deferred account in accordance with ASC 980, "Regulated Operations" (ASC 980) 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 and the gains and losses on the hedges in future periods will be recorded as gas costs.*

For further details regarding the fair value of derivative instruments, see Note 10.

The following tables present the net unrealized (gain) loss of the Company's derivative instruments recorded on the statements of income:

Puget Energy	Year Ended December 31,		
(Dollars in Thousands)	2012	2011	2010
Gas / Power NPNS [1]	$ (2,199)	$ (11,677)	$ (40,564)
Gas for power generation	(53,180)	(23,993)	37,535
Power exchange	—	—	(2,619)
Power	(78,227)	47,164	59,743
Total net unrealized (gain) loss on derivative instruments	$ (133,606)	$ 11,494	$ 54,095
Interest expense – interest rate swaps	$ 2,932	$ 21,159	$ (10,918)
Other deductions – interest rate swaps	$ (16,006)	$ 12,388	$ 7,319

1 *Amount represents amortization related to contracts that were recorded at fair value as of the date of the merger.*

Puget Sound Energy	Year Ended December 31,		
(Dollars in Thousands)	2012	2011	2010
Gas for power generation	$ (53,177)	$ (4,043)	$ 91,666
Power exchange			(2,620)
Power	(65,943)	58,189	77,907
Total net unrealized (gain) loss on derivative instruments	$ (119,120)	$ 54,146	$ 166,953

The following tables present the pre-tax gain (loss) of the Company's derivatives that were in a previous cash flow hedge relationship, reclassified out of accumulated OCI into income:

Puget Energy		Year Ended December 31,		
(Dollars in Thousands)	Location	2012	2011	2010
Interest rate contracts:	Interest expense	$ (17,811)	$ (39,143)	$ (33,887)
Commodity contracts:				
Electric derivatives	Electric generation fuel	100	(679)	(3,347)
	Purchased electricity	(671)	(1,698)	(3,453)
Total		$ (18,382)	$ (41,520)	$ (40,687)

Puget Sound Energy		Year Ended December 31,		
(Dollars in Thousands)	Location	2012	2011	2010
Interest rate contracts:	Interest expense	$ (488)	$ (488)	$ (488)
Commodity contracts:				
Electric derivatives	Electric generation fuel	97	(20,625)	(57,479)
	Purchased electricity	(12,955)	(12,726)	(17,207)
Total		$ (13,346)	$ (33,839)	$ (75,174)

For derivative instruments designated as cash flow hedges, the effective portion of the gain or loss on the derivative was reported as a component of OCI, and then reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. There were no additional amounts deferred into OCI during 2012 or 2011. Puget Energy expects that $4.5 million of losses in accumulated OCI will be reclassified into earnings within the next twelve months. PSE expects that $3.9 million of losses in accumulated OCI will be reclassified into earnings within the next twelve months. The maximum length of time over which the Company is economically hedging its exposure to the variability in future cash flows extends to December

2015 for purchased electricity contracts, October 2018 for gas for power generation contracts and January 2017 for interest rate swaps.

The following tables present the effect of the Company's derivatives not designated as hedging instruments in income:

Puget Energy		Year Ended December 31,		
(Dollars in Thousands)	Location	2012	2011	2010
Interest rate contracts:	Non-hedged interest rate derivative expense	$ (4,288)	$ (28,601)	$ (7,955)
	Interest expense	(29,727)	(46,045)	9,423
Commodity contracts:				
Electric derivatives	Unrealized gain (loss) on derivative instruments, net [1]	131,407	(23,171)	(94,659)
	Electric generation fuel	(66,762)	(98,208)	(100,514)
	Purchased electricity	(138,551)	(66,845)	(36,886)
Total gain (loss) recognized in income on derivatives		$ (107,921)	$ (262,870)	$ (230,591)

[1] *Differs from the amounts stated in the statements of income as it does not include amortization related to contracts that were recorded at fair value at the time of the February 2009 merger and subsequently designated as NPNS of $2.2 million for the twelve months ended December 31, 2012 and $11.7 million for the twelve months ended December 31, 2011, and $40.6 million for the twelve months ended December 31, 2010.*

Puget Sound Energy		Year Ended December 31,		
(Dollars in Thousands)	Location	2012	2011	2010
Commodity contracts:				
Electric derivatives	Unrealized gain (loss) on derivative instruments, net	$ 119,120	$ (54,146)	$ (166,953)
	Electric generation fuel	(66,762)	(98,208)	(100,514)
	Purchased electricity	(138,551)	(66,845)	(36,886)
Total gain (loss) recognized in income on derivatives		$ (86,193)	$ (219,199)	$ (304,353)

The Company had the following outstanding interest rate and commodity contracts as of December 31, 2012:

Derivatives not designated as hedging instruments:	Number of Units
Puget Energy:	
Interest rate swaps	$450.0 million
Puget Energy and Puget Sound Energy:	
Natural gas derivatives	516,909,006 MMBtus
Electric generation fuel	129,693,200 MMBtus
Purchased electricity	10,722,415 MWhs

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

The Company monitors counterparties that have significant swings in credit default swap rates, have credit rating changes by external rating agencies, have changes in ownership or are experiencing financial problems. Where deemed appropriate, the Company may request collateral or other security from its counterparties to mitigate potential credit default losses. Criteria employed in this decision include, among other things, the perceived creditworthiness of the counterparty and the expected credit exposure.

It is possible that volatility in energy commodity prices could cause the Company to have material credit risk exposure 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, 2012, approximately 99.9% of the Company's energy portfolio exposure, excluding NPNS transactions, is with counterparties that are rated at least investment grade by the major rating agencies and 0.1% are either rated below investment grade or not rated by rating agencies. The Company assesses credit risk internally for counterparties that are not rated.

The Company generally enters into transactions using the following master agreements: (1) WSPP, Inc. (WSPP) agreement - standardized power sales contract in the electric industry; (2) International Swaps and Derivatives Association (ISDA) agreements - standardized financial gas and electric contracts; and (3) North American Energy Standards Board (NAESB) agreements - standardized physical gas contracts. The Company believes that such agreements reduce credit risk exposure because such agreements provide for the netting and offsetting of monthly payments and, in the event of counterparty default, termination payments.

The Company computes credit reserves at a master agreement level by counterparty (i.e., WSPP, ISDA, or NAESB). The Company considers external credit ratings and market factors, such as credit default swaps and bond spreads, in the 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 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 the fair value 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. For those in a net liability position, the Company calculates the credit reserve by using its own bond spreads. The fair value of derivative instruments includes the impact of credit reserves. As of December 31, 2012, 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 quarter. The majority of the Company's derivative contracts are with financial institutions and other utilities operating within the Western Electricity Coordinating Council. Despite its net liability position, PSE was not required to post any additional collateral with any of its counterparties. Additionally, PSE did not trigger any collateral requirements with any of its counterparties nor were any of PSE's counterparties required to post additional collateral resulting from credit rating downgrades.

As of December 31, 2012, the Company did not have any outstanding energy supply contracts with counterparties that contained credit risk related contingent features, which could result in a counterparty requesting immediate payment or demanding 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, 2012:

Puget Energy and Puget Sound Energy Contingent Feature (Dollars in Thousands)	Fair Value [1] Liability	Posted Collateral	Contingent Collateral
Credit rating [2]	$ (31,995)	$ —	$ 31,995
Requested credit for adequate assurance	(41,311)	—	—
Forward value of contract [3]	(4,261)	—	—
Total	$ (77,567)	$ —	$ 31,995

1 *Represents the derivative fair value of contracts with contingent features for counterparties in net derivative liability positions. Excludes NPNS, accounts payable and accounts receivable.*

2 *Failure by PSE to maintain an investment grade credit rating from each of the major credit rating agencies provides counterparties a contractual right to demand collateral.*

3 *Collateral requirements may vary, based on changes in the forward value of underlying transactions relative to contractually defined collateral thresholds.*

(10) Fair Value Measurements

GAAP established a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy categorizes the inputs into three levels with the highest priority given to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority given to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are as follows:

> Level 1 - Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. 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 reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. 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 have little or no observability as of the reporting date. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Therefore, if a fair value measurement relies on significant inputs from different levels of the hierarchy, the entire measurement must be placed based on the lowest level. 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. The Company primarily determines fair value measurements classified as Level 2 or Level 3 using a combination of the income and market valuation approaches. The process of determining the fair values is the responsibility of the derivative accounting department which reports to the Controller and Principal Accounting Officer. On a daily basis, the Company obtains quoted forward prices for the electric and natural gas market from an independent external pricing service. These forward price quotes are used in addition to other various inputs to determine the reported fair value. Some of the inputs, which are not significant, include the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests), assumptions for time value, and also the impact of the Company's non-performance risk of its liabilities. For interest rate swaps, the Company obtains monthly mark-to-market values from an independent external pricing service for LIBOR forward rates, which is a significant input. Some of the inputs of the interest rate swap valuations, which are not significant, include the credit standing of the counterparties, assumptions for time value and the impact of the Company's non-performance risk of its liabilities. Cash equivalents and restricted cash classified as Level 2 fair value instruments consist of special money market funds and premium checking accounts. The Company valued Level 2 cash equivalents and restricted cash using the market approach based on the fair value of underlying investments at reporting date.

The Company considers its electric, natural gas and interest rate swap contracts as Level 2 derivative instruments as such contracts are commonly traded as over-the-counter forwards with indirectly observable price quotes. However, certain energy derivative instruments are classified as Level 3 in the fair value hierarchy since Level 3 inputs are significant to the fair value measurement. Management's assessment was based on the trading activity in real-time and forward electric and natural gas markets. Each quarter, the Company confirms the validity of pricing service quoted prices (e.g., Level 2 in the fair value hierarchy) used to value commodity contracts with the actual prices of commodity contracts entered into during the most recent quarter.

Assets and Liabilities with Estimated Fair Value

The following table presents the carrying value for cash, cash equivalents, restricted cash, notes receivable and short-term debt by level, within the fair value hierarchy. The carrying values below are representative of fair values due to the short-term nature of these financial instruments.

Puget Energy	Carrying / Fair Value At December 31, 2012			Carrying / Fair Value At December 31, 2011		
(Dollars in Thousands)	Level 1	Level 2	Total	Level 1	Level 2	Total
Assets:						
Cash and Cash Equivalents	$ 105,000	$ 30,542	$ 135,542	$ 14,809	$ 22,426	$ 37,235
Restricted Cash	914	2,786	3,700	2,043	2,140	4,183
Notes Receivable and Other	—	63,802	63,802	—	73,031	73,031
Total assets	$ 105,914	$ 97,130	$ 203,044	$ 16,852	$ 97,597	$ 114,449
Liabilities:						
Short Term Debt	$ 181,000	$ —	$ 181,000	$ —	$ 25,000	$ 25,000
Total liabilities	$ 181,000	$ —	$ 181,000	$ —	$ 25,000	$ 25,000

Puget Sound Energy	Carrying / Fair Value At December 31, 2012			Carrying / Fair Value At December 31, 2011		
(Dollars in Thousands)	Level 1	Level 2	Total	Level 1	Level 2	Total
Assets:						
Cash and Cash Equivalents	$ 105,000	$ 30,530	$ 135,530	$ 9,200	$ 21,810	$ 31,010
Restricted Cash	914	2,786	3,700	2,043	2,140	4,183
Notes Receivable and Other	—	63,802	63,802	—	73,031	73,031
Total assets	$ 105,914	$ 97,118	$ 203,032	$ 11,243	$ 96,981	$ 108,224
Liabilities:						
Short Term Debt	$ 181,000	$ —	$ 181,000	$ —	$ 25,000	$ 25,000
Short Term Debt owed to parent	—	29,598	29,598	—	29,998	29,998
Total liabilities	$ 181,000	$ 29,598	$ 210,598	$ —	$ 54,998	$ 54,998

The fair value of the junior subordinated and long-term notes were estimated using the discounted cash flow method with U.S. Treasury yields and Company credit spreads as inputs, interpolating to the maturity date of each issue. Carrying values and estimated fair values were as follows:

Puget Energy		December 31, 2012		December 31, 2011	
(Dollars in Thousands)	Level	Carrying Value	Fair Value	Carrying Value	Fair Value
Liabilities:					
Junior subordinated notes	2	$ 250,000	$ 264,842	$ 250,000	$ 248,583
Long-term debt (fixed-rate), net of discount	2	4,662,200	6,197,179	4,197,511	5,503,571
Long-term debt (variable-rate), net of discount	2	434,000	434,000	829,856	856,978
Total		$ 5,346,200	$ 6,896,021	$ 5,277,367	$ 6,609,132

Puget Sound Energy		December 31, 2012		December 31, 2011	
(Dollars in Thousands)	Level	Carrying Value	Fair Value	Carrying Value	Fair Value
Liabilities:					
Junior subordinated notes	2	$ 250,000	$ 264,842	$ 250,000	$ 248,583
Long-term debt (fixed-rate), net of discount	2	3,526,258	4,628,509	3,523,845	4,499,295
Total		$ 3,776,258	$ 4,893,351	$ 3,773,845	$ 4,747,878

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The following tables present the Company's financial assets and liabilities by level, within the fair value hierarchy, that were accounted for at fair value on a recurring basis and the reconciliation of the changes in the fair value of Level 3 derivatives in the fair value hierarchy. The Company did not have any transfers between Level 2 and Level 1 during the twelve months ended December 31, 2012 and 2011.

Puget Energy	Fair Value At December 31, 2012			Fair Value At December 31, 2011		
(Dollars in Thousands)	Level 2	Level 3	Total	Level 2	Level 3	Total
Interest rate derivative instruments	$ 21,524	$ —	$ 21,524	$ 52,409	$ —	$ 52,409
Total derivative liabilities	$ 21,524	$ —	$ 21,524	$ 52,409	$ —	$ 52,409

Puget Energy and Puget Sound Energy	Fair Value At December 31, 2012			Fair Value At December 31, 2011		
(Dollars in Thousands)	Level 2	Level 3	Total	Level 2	Level 3	Total
Assets:						
Electric derivative instruments	$ 1,259	$ 8,298	$ 9,557	$ 2,340	$ 8,380	$ 10,720
Natural gas derivative instruments	6,769	5,357	12,126	—	6,011	6,011
Total assets	$ 8,028	$ 13,655	$ 21,683	$ 2,340	$ 14,391	$ 16,731
Liabilities:						
Electric derivative instruments	$ 88,971	$ 42,221	$ 131,192	$ 165,643	$ 98,691	$ 264,334
Natural gas derivative instruments	101,119	6,960	108,079	195,852	11,052	206,904
Total liabilities	$ 190,090	$ 49,181	$ 239,271	$ 361,495	$ 109,743	$ 471,238

Puget Energy and Puget Sound Energy	Twelve Months Ended December 31,								
Level 3 Roll-Forward Net (Liability)	2012			2011			2010		
(Dollars in Thousands)	Electric	Gas	Total	Electric	Gas	Total	Electric	Gas	Total
Balance at beginning of period	$ (90,311)	$ (5,041)	$ (95,352)	$ (87,436)	$ (3,859)	$ (91,295)	$ (96,330)	$ (4,003)	$ (100,333)
Changes during period									
Realized and unrealized energy derivatives:									
Included in earnings [1]	(21,362)	—	(21,362)	(56,499)	—	(56,499)	(112,180)	—	(112,180)
Included in regulatory assets / liabilities	—	(1,937)	(1,937)	—	(250)	(250)	—	(2,665)	(2,665)
Settlements [2]	59,133	969	60,102	40,900	(3,418)	37,482	30,625	(793)	29,832
Transferred into Level 3	(55,548)	(297)	(55,845)	(759)	453	(306)	326	(101)	225
Transferred out of Level 3	74,164	4,704	78,868	13,483	2,033	15,516	90,123	3,703	93,826
Balance at end of period	$ (33,924)	$ (1,602)	$ (35,526)	$ (90,311)	$ (5,041)	$ (95,352)	$ (87,436)	$ (3,859)	$ (91,295)

1 *Income Statement location: Unrealized (gain) loss on derivative instruments, net. Includes unrealized gains (losses) on derivatives still held in position as of the reporting date for electric derivatives of $(15.2) million, $(55.2) million, and $(89.4) million for the twelve months ended December 31, 2012, 2011 and 2010, respectively.*

2 *The Company had no purchases, sales or issuances during the reported periods.*

Realized gains and losses on energy derivatives for Level 3 recurring items are included in energy costs in the Company's consolidated statements of income under purchased electricity, electric generation fuel or purchased natural gas when settled. Unrealized gains and losses on energy derivatives for Level 3 recurring items are included in net unrealized (gain) loss on derivative instruments in the Company's consolidated statements of income.

In order to determine which assets and liabilities are classified as Level 3, the Company receives market data from its independent external pricing service defining the tenor of observable market quotes. To the extent any of the Company's commodity contracts extend beyond what is considered observable as defined by its independent pricing service, the contracts are classified as Level 3. The actual tenor of what the independent pricing service defines as observable is subject to change depending on market conditions. Therefore, as the market changes, the same contract may be designated Level 3 one month and Level 2 the next, and vice versa. The changes of fair value classification into or out of Level 3 are recognized each month, and reported in the Level 3 Roll-forward table above. The Company does periodically transact at locations, or market price points, that are illiquid or for which no prices are available from the independent pricing service. In such circumstances the Company uses a more liquid price point and performs a 15-month regression against the illiquid locations to serve as a proxy for market prices. Such transactions are classified as Level 3. The Company does not use internally developed models to make adjustments to significant unobservable pricing inputs. The only significant unobservable input into the fair value measurement of the Company's Level 3 assets and liabilities is the forward price for electric and natural gas contracts. Below are the forward price ranges for the Company's purchased commodity contracts, as of December 31, 2012:

(Dollars in Thousands)

	Fair Value				Range		
Derivative Instrument	Assets [1]	Liabilities [1]	Valuation Technique	Unobservable Input	Low	High	Weighted Average
Electric	$8,298	$42,221	Discounted cash flow	Power Prices	$13.39 per MWh	$67.79 per MWh	$45.11 per MWh
Natural gas	$5,357	$6,960	Discounted cash flow	Natural Gas Prices	$3.76 per MMBtu	$5.07 per MMBtu	$4.26 per MMBtu

1 *The valuation techniques, unobservable inputs and ranges are the same for asset and liability positions.*

The significant unobservable inputs listed above would have a direct impact on the fair values of the above instruments if they were adjusted. Consequently significant increases or decreases in the forward prices of electricity or natural gas in isolation would result in a significantly higher or lower fair value for Level 3 assets and liabilities. Generally, interrelationships exist between market prices of natural gas and power. As such, an increase in natural gas pricing would potentially have a similar impact on forward power markets. At December 31, 2012, a hypothetical 10% increase or decrease in market prices of natural gas and electricity would change the fair value of the Company's derivative portfolio, classified as Level 3 within the fair value hierarchy, by $17.8 million .

Long-Lived Assets Measured at Fair Value on a Nonrecurring Basis

At the time of merger, Puget Energy recorded the fair value of its intangible assets in accordance with ASC 360, “Property, Plant, and Equipment,” (ASC 360). The fair value assigned to the power contracts was determined using an income approach comparing the contract rate to the market rate for power over the remaining period of the contracts incorporating non-performance risk. Management also incorporated certain assumptions related to quantities and market presentation that it believes market participants would make in the valuation. The fair value of the power contracts is amortized as the contracts settle.

ASC 360 requires long-lived assets to be tested for impairment on an annual basis, and upon the occurrence of any events or circumstances that would be more likely than not to reduce the fair value of the long-lived assets below their carrying value. One such triggering event is a significant decrease in the forward market prices of power.

At December 31, 2012, Puget Energy completed a valuation and impairment test of its purchased power contracts classified as intangible assets. The valuation indicated a fair value of $561.3 million with an impairment to one of the purchased power contracts. As of December 31, 2012, the carrying value for the Rock Island intangible asset contract was $7.6 million and its fair value on a discounted basis was determined to be a liability of $10.2 million, thereby requiring a complete write-off of the intangible asset with a corresponding $7.6 million reduction to the regulatory liability.

The valuation was measured using the income approach. Significant inputs included forward electricity prices and power contract costs which provided future net cash flow estimates which are classified as Level 3 within the fair value hierarchy. An insignificant input is the discount rate reflective of PSE's cost of capital used in the valuation. Below are the significant unobservable inputs used in the fourth quarter in estimating the fair value of the Rock Island long-term power purchase contract during the period ended December 31, 2012:

Valuation Technique	Unobservable Input	Low	High	Weighted Average
Discounted cash flow	Power prices	$16.94 per MWh	$70.89 per MWh	$49.40 per MWh
Discounted cash flow	Power contract costs (in thousands)	$1,777 per qtr	$7,133 per qtr	$6,603 per qtr

At March 31, 2012, due to decreasing forward wholesale market prices, Puget Energy completed a valuation and impairment test for its purchase power contracts classified as intangible assets. The valuation indicated impairment to one of the purchased power contracts. As of March 31, 2012, the carrying value for the Wells Hydro intangible asset contract was $113.3 million and its fair value on a discounted basis was determined to be $96.7 million, thereby requiring a $16.6 million write-down of the intangible asset with a corresponding reduction in the regulatory liability. Below are significant unobservable inputs used in the first quarter in estimating the fair value of the Wells Hydro long-term power purchase contract during the period ended March 31, 2012:

Valuation Technique	Unobservable Input	Low	High	Weighted Average
Discounted cash flow	Power prices	$10.36 per MWh	$49.78 per MWh	$34.98 per MWh
Discounted cash flow	Power contract costs (in thousands)	$3,185 per qtr	$5,030 per qtr	$4,663 per qtr

At December 31, 2011, Puget Energy completed a valuation and impairment test for its purchased power contracts classified as intangible assets. The valuation indicated a fair value of $619.9 million with an impairment to two of the purchased power contracts, the WNP-3 BPA Exchange Power contract and the Rock Island hydro contract. As of December 31, 2011, the carrying value for the WNP-3 BPA intangible asset contract was $1.9 million and its fair value on a discounted basis was less than zero thereby requiring a full write-off of the intangible asset with a corresponding reduction in the regulatory liability. The carrying value for the Rock Island intangible asset contract was $44.9 million and its fair value on a discounted basis was determined to be $9.8 million thereby requiring a $35.1 million write-down of the intangible asset with a corresponding reduction in the regulatory liability.

(11) Employee Investment Plans

The Company has a qualified employee Investment Plan which is a 401(k) plan, under which employee salary deferrals and after-tax contributions are used to purchase several different investment fund options. For employees under the Cash Balance retirement plan formula, PSE will match 100% of an employee's contribution up to 6% of plan compensation, and will make an additional year-end contribution equal to 1% of base pay. For employees grandfathered under the Final Average Earning retirement plan formula, PSE will match 55% of an employee’s contribution up to 6% of plan compensation. PSE’s contributions to the employee Investment Plan were $14.5 million, $13.5 million and $11.8 million for the years 2012, 2011, and 2010, respectively. The employee Investment Plan eligibility requirements are set forth in the plan documents.

(12) Retirement Benefits

PSE has a defined benefit pension plan covering substantially all PSE employees. Pension benefits earned are a function of age, salary and years of service. PSE also maintains a non-qualified Supplemental Executive Retirement Plan (SERP) for its key senior management employees. In addition to providing pension benefits, PSE provides certain health care and life insurance benefits for employees. These benefits are provided principally through an insurance company. The insurance premiums are based on the benefits provided during the year, and are paid primarily by retirees.

The following tables summarize the Company's change in benefit obligation, change in plan assets and amounts recognized in the Statements of Financial Position for the years ended December 31, 2012 and 2011:

Puget Energy and Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2012	2011	2012	2011	2012	2011
Change in benefit obligation:						
Benefit obligation at beginning of period	$ 565,997	$ 532,615	$ 48,370	$ 44,322	$ 16,436	$ 16,579
Service cost	16,926	15,822	1,073	1,241	139	113
Interest cost	25,986	26,263	2,152	2,192	751	806
Amendment	—	—	(122)	—	—	—
Actuarial loss	40,914	18,485	5,483	4,467	1,199	384
Benefits paid	(33,533)	(27,188)	(5,161)	(2,687)	(1,523)	(1,855)
Medicare part D subsidy received	—	—	—	—	670	409
Curtailment loss/(gain)	—	—	—	(1,165) [1]	—	—
Benefit obligation at end of period	$ 616,290	$ 565,997	$ 51,795	$ 48,370	$ 17,672	$ 16,436

[1] *A curtailment gain was recognized in OCI due to the plan amendment that ceased SERP benefits for non-officers still in the plan as of December 31, 2011.*

Puget Energy and Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2012	2011	2012	2011	2012	2011
Change in plan assets:						
Fair value of plan assets at beginning of period	$ 479,786	$ 526,469	$ —	$ —	$ 7,206	$ 8,288
Actual return on plan assets	62,130	(24,495)	—	—	1,100	(170)
Employer contribution	22,800	5,000	5,161	2,687	758	943
Benefits paid	(33,533)	(27,188)	(5,161)	(2,687)	(1,523)	(1,855)
Fair value of plan assets at end of period	$ 531,183	$ 479,786	$ —	$ —	$ 7,541	$ 7,206
Funded status at end of period	$ (85,107)	$ (86,211)	$ (51,795)	$ (48,370)	$ (10,131)	$ (9,230)

Puget Energy and Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2012	2011	2012	2011	2012	2011
Amounts recognized in Statement of Financial Position consist of:						
Current liabilities	$ —	$ —	$ (5,040)	$ (6,137)	$ (460)	$ (468)
Noncurrent liabilities	(85,107)	(86,211)	(46,755)	(42,233)	(9,671)	(8,762)
Total	$ (85,107)	$ (86,211)	$ (51,795)	$ (48,370)	$ (10,131)	$ (9,230)

The following tables summarize Puget Energy and Puget Sound Energy's pension benefit amounts recognized in Accumulated Other Comprehensive income for the years ended December 31, 2012 and 2011:

Puget Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2012	2011	2012	2011	2012	2011
Amounts recognized in Accumulated Other Comprehensive Income consist of:						
Net loss/(gain)	$ 49,001	$ 34,781	$ 12,818	$ 8,038	$ 763	$ 282
Prior service cost	(17,741)	(19,721)	(122)	—	—	—
Total	$ 31,260	$ 15,060	$ 12,696	$ 8,038	$ 763	$ 282

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2012	2011	2012	2011	2012	2011
Amounts recognized in Accumulated Other Comprehensive Income consist of:						
Net loss/(gain)	$ 269,401	$ 264,098	$ 17,928	$ 13,878	$ (2,175)	$ (2,955)
Prior service cost/(credit)	(14,098)	(15,671)	(110)	305	36	72
Transition obligations	—	—	—	—	—	50
Total	$ 255,303	$ 248,427	$ 17,818	$ 14,183	$ (2,139)	$ (2,833)

The following tables summarize Puget Energy's and Puget Sound Energy's net periodic benefit cost for the years ended December 31, 2012, 2011 and 2010:

Puget Energy	Qualified Pension Benefits			SERP Pension Benefits			Other Benefits		
(Dollars in Thousands)	2012	2011	2010	2012	2011	2010	2012	2011	2010
Components of net periodic benefit cost:									
Service cost	$ 16,926	$ 15,822	$ 16,089	$ 1,073	$ 1,241	$ 1,024	$ 139	$ 113	$ 106
Interest cost	25,986	26,263	27,975	2,152	2,192	2,165	751	806	880
Expected return on plan assets	(36,203)	(35,344)	(32,941)	—	—		(435)	(502)	(510)
Amortization of prior service cost/(credit)	(1,980)	(1,980)	(165)	—	—	—	—	—	—
Amortization of net loss	768	—	70	702	360	—	53	(46)	(67)
Net periodic benefit cost	$ 5,497	$ 4,761	$ 11,028	$ 3,927	$ 3,793	$ 3,189	$ 508	$ 371	$ 409

Puget Sound Energy	Qualified Pension Benefits			SERP Pension Benefits			Other Benefits		
(Dollars in Thousands)	2012	2011	2010	2012	2011	2010	2012	2011	2010
Components of net periodic benefit cost:									
Service cost	$ 16,926	$ 15,822	$ 16,089	$ 1,073	$ 1,241	$ 1,024	$ 139	$ 113	$ 106
Interest cost	25,986	26,263	27,975	2,152	2,192	2,165	751	806	880
Expected return on plan assets	(41,533)	(44,128)	(43,892)	—	—	—	(435)	(502)	(509)
Amortization of prior service cost/(credit)	(1,573)	(1,573)	548	293	563	562	35	63	132
Amortization of net loss/ (gain)	15,015	10,250	7,325	1,432	1,194	769	(245)	(481)	(553)
Amortization of transition obligation	—	—	—	—	—	—	50	50	50
Net periodic benefit cost	$ 14,821	$ 6,634	$ 8,045	$ 4,950	$ 5,190	$ 4,520	$ 295	$ 49	$ 106

The following tables summarize Puget Energy's and Puget Sound Energy's benefit obligations recognized in other comprehensive income for the years ended December 31, 2012 and 2011:

Puget Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2012	2011	2012	2011	2012	2011
Other changes (pre-tax) in plan assets and **benefit obligations recognized in other comprehensive income:**						
Net loss/(gain)	$ 14,988	$ 78,324	$ 5,483	$ 3,302	$ 534	$ 1,056
Amortization of net loss/(gain)	(768)	—	(703)	(360)	(53)	46
Prior service credit	—	—	(122)	—	—	—
Amortization of prior service credit	1,980	1,980	—	—	—	—
Total change in other comprehensive income for year	$ 16,200	$ 80,304	$ 4,658	$ 2,942	$ 481	$ 1,102

Puget Sound Energy	Qualified Pension Benefit		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2012	2011	2012	2011	2012	2011
Other changes (pre-tax) in plan assets and benefit obligations recognized in other comprehensive income:						
Net loss/(gain)	$ 20,318	$ 87,108	$ 5,483	$ 3,302	$ 534	$ 1,056
Amortization of net (loss)/gain	(15,015)	(10,250)	(1,433)	(1,194)	245	481
Prior service cost/(credit)	—	—	(122)	—	—	—
Amortization of prior service cost/(credit)	1,573	1,573	(293)	(562)	(35)	(62)
Amortization of transition obligation	—	—	—	—	(50)	(50)
Total change in other comprehensive income for year	$ 6,876	$ 78,431	$ 3,635	$ 1,546	$ 694	$ 1,425

The estimated net/(loss) gain and prior service/(cost) credit for the pension plans that will be amortized from accumulated OCI into net periodic benefit cost in 2013 by Puget Energy are $(2.6) million and $2.0 million, respectively. The estimated net (loss)/gain for the SERP that will be amortized from accumulated OCI into net periodic benefit cost in 2013 are $(1.5) million. The estimated prior service (cost)/credit for the SERP that will be amortized from accumulated OCI into net periodic benefit cost in 2013 is immaterial. The estimated net (loss)/gain, prior service cost/(credit) and transition/(obligation) asset for the other postretirement plans that will be amortized from accumulated OCI into net periodic benefit cost in 2013 are immaterial.

The estimated net (loss)/gain and prior service (cost)/credit for the pension plans that will be amortized from accumulated OCI into net periodic benefit cost in 2013 by Puget Sound Energy are $(20.3) million and $1.6 million, respectively. The estimated net loss/(gain) and prior service (cost)/credit for the SERP that will be amortized from accumulated OCI into net periodic benefit cost in 2013 are $(2.2) million. The estimated prior service (cost)/credit for the SERP that will be amortized from accumulated OCI into net periodic benefit cost in 2013 is immaterial. The estimated net (loss)/gain for the other postretirement plan that will be amortized from accumulated OCI into net periodic benefit cost in 2013 is $0.1 million and prior service (cost)/credit and transition (obligation)/asset for the other postretirement plans are immaterial.

The aggregate expected contributions by the Company to fund the retirement plan, SERP and the other postretirement plans for the year ending December 31, 2013 are expected to be at least $20.4 million, $5.0 million and $0.8 million, respectively.

Assumptions

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

	Qualified Pension Benefits			SERP Pension Benefits			Other Benefits		
Benefit Obligation Assumptions	2012	2011	2010	2012	2011	2010	2012	2011	2010
Discount rate [1]	4.15%	4.75%	5.15%	4.15%	4.75%	5.15%	4.15%	4.75%	5.15%
Rate of compensation increase	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
Medical trend rate	—	—	—	—	—	—	7.50%	7.50%	8.00%
Benefit Cost Assumptions									
Discount rate	4.75%	5.15%	5.75%	4.75%	5.15%	5.75%	4.75%	5.15%	5.75%
Rate of plan assets	7.75%	7.75%	8.00%	—	—	—	7.50%	7.80%	7.80%
Rate of compensation increase	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
Medical trend rate	—	—	—	—	—	—	7.50%	8.00%	8.50%

1 *The Company calculates the present value of the pension liability using a discount rate of 4.15% which represents the single-rate equivalent of the AA rated corporate bond yield curve.*

The assumed medical inflation rate used to determine benefit obligations is 7.50% in 2013 grading down to 4.80% in 2014. A 1.0% change in the assumed medical inflation rate would have the following effects:

	2012		2011	
(Dollars in Thousands)	1% Increase	1% Decrease	1% Increase	1% Decrease
Effect on post-retirement benefit obligation	$ 92	$ 92	$ 97	$ 85
Effect on service and interest cost components	4	4	5	4

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. PSE 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.

Puget Energy'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 costs trends. Changes in any of these factors or assumptions will affect the amount of income or expense that Puget Energy records in its financial statements in future years and its projected benefit obligation. Puget Energy has selected an expected return on plan assets based on a historical analysis of rates of return and Puget Energy's investment mix, market conditions, inflation and other factors. As required by merger accounting rules, market-related value was reset to market value effective with the merger.

The discount rates were 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.

Plan Benefits

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

(Dollars in Thousands)	2013	2014	2015	2016	2017	2018-2022
Qualified Pension total benefits	$ 38,500	$ 38,400	$ 38,800	$ 39,000	$ 40,000	$ 216,900
SERP Pension total benefits	5,040	3,799	3,437	3,510	1,883	21,338
Other Benefits total with Medicare Part D subsidy	1,326	1,282	1,315	1,259	1,199	6,853
Other Benefits total without Medicare Part D subsidy	1,713	1,691	1,656	1,607	1,557	7,031

Plan Assets

Plan contributions and the actuarial present value of accumulated plan benefits are prepared based on certain assumptions pertaining to interest rates, inflation rates and employee demographics, all of which are subject to change. Due to uncertainties inherent in the estimations and assumptions process, changes in these estimates and assumptions in the near term may be material to the financial statements.

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
Domestic large cap equity	25%	32%	40%
Domestic small cap equity	0%	10%	15%
Non-U.S. equity	10%	20%	30%
Tactical asset allocation	0%	5%	10%
Fixed income	15%	23%	30%
Real estate	0%	0%	10%
Absolute return	5%	10%	15%
Cash	0%	0%	5%

Plan Fair Value Measurements

ASC 715, "Compensation – Retirement Benefits" (ASC 715) 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 disclose the following: (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.

ASC 820 allows the reporting entity, as a practical expedient, to measure the fair value of investments that do not have readily determinable fair values on the basis of the net asset value per share of the investment if the net asset value of the investment is calculated in a matter consistent with ASC 946, "Financial Services – Investment Companies." The standard requires disclosures about the nature and risk of the investments and whether the investments are probable of being sold at amounts different from the net asset value per share.

The following table sets forth by level, within the fair value hierarchy, the qualified pension plan as of December 31, 2012 and 2011:

	Recurring Fair Value Measures As of December 31, 2012				Recurring Fair Value Measures As of December 31, 2011			
(Dollars in Thousands)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Equities:								
Non-US equity [1]	$ 56,717	$ 49,304	$ —	$106,021	$ 48,382	$ 42,132	$ —	$ 90,514
Domestic large cap equity [2]	136,994	28,890	—	165,884	124,303	29,547	—	153,850
Domestic small cap equity [3]	51,264	—	—	51,264	45,650	—	—	45,650
Total equities	244,975	78,194	—	323,169	218,335	71,679	—	290,014
Tactical asset allocation [4]	—	26,425	—	26,425	—	26,922	—	26,922
Fixed income securities [5]	119,939	—	—	119,939	106,573	580	—	107,153
Absolute return [6]	—	—	55,615	55,615	—	—	45,319	45,319
Cash and cash equivalents [7]	—	6,019	—	6,019	—	9,015	—	9,015
Subtotal	$364,914	$110,638	$55,615	$531,167	$324,908	$108,196	$45,319	$478,423
Net (payable) receivable				(173)				1,088
Accrued income				189				275
Total assets				$531,183				$479,786

1 *Non – US Equity investments are comprised of a (1) mutual fund; and a (2) commingled fund. The investment in the mutual fund is valued using quoted market prices multiplied by the number of shares owned as of December 31, 2012. The investment in the commingled fund is valued at the net asset value per share multiplied by the number of shares held as of December 31, 2012.*

2 *Domestic large cap equity investments are comprised of (1) common stock, and a (2) commingled fund. Investments in common stock are valued using quoted market prices multiplied by the number of shares owned as of December 31, 2012. The investment in the commingled fund is valued at the net asset value per share multiplied by the number of shares held as of December 31, 2012.*

3 *Domestic small cap equity investments are comprised of (1) common stock and a (2) mutual fund. The investments in common stock are valued using quoted market prices multiplied by the number of shares owned as of December 31, 2012. The investment in the mutual fund is valued using quoted market prices multiplied by the number of shares owned as of December 31, 2012.*

4 *The tactical asset allocation investment is comprised of a commingled fund, which is valued at the net asset value per share multiplied by the number of shares held as of the measurement date.*

5 *Fixed income securities consist of a mutual fund. The investment in the mutual fund is valued using quoted market prices multiplied by the number of shares owned as of December 31, 2012.*

6 *As of December 31, 2012 absolute return investments consist of two partnerships. The partnerships are valued using the financial reports as of December 31, 2012. These investments are a Level 3 under ASC 820 because the significant valuation inputs are primarily internal to the partnerships with little third party involvement.*

7 *The investment consists of a money market fund, which is valued at the net asset value per share of $1.00 per unit as of December 31, 2012. The money market fund invests primarily in commercial paper, notes, repurchase agreements, and other evidences of indebtedness which are payable on demand or short-term in nature.*

Level 3 Roll-Forward

The following table sets forth a reconciliation of changes in the fair value of the plan's Level 3 assets:

	As of December 31, 2012			As of December 31, 2011		
(Dollars in Thousands)	Partnership	Mutual Funds	Total	Partnership	Mutual Funds	Total
Balance at beginning of year	$ 45,319	$ —	$ 45,319	$ 35,481	$ 12,619	$ 48,100
Additional investments	7,021	—	7,021	11,635	—	11,635
Distributions	—	—	—	—	(11,635)	(11,635)
Realized losses on distributions	—	—	—	—	(290)	(290)
Unrealized gains relating to instruments still held at the reporting date	3,274	—	3,274	(1,797)	599	(1,198)
Transferred out of level 3 [1]	—	—	—	—	(1,293)	(1,293)
Balance at end of year	$ 55,614	$ —	$ 55,614	$ 45,319	$ —	$ 45,319

1 *The plan had no transfers between level 2 and level 1 during the years ended December 31, 2012 or 2011.*

The following table sets forth by level, within the fair value hierarchy, the Other Benefits plan assets which consist of insurance benefits for retired employees, at fair value:

	Recurring Fair Value Measures As of December 31, 2012			Recurring Fair Value Measures As of December 31, 2011		
(Dollars in Thousands)	Level 1	Level 2	Total	Level 1	Level 2	Total
Assets:						
Mutual fund [1]	$ 7,472	$ —	$ 7,472	$ 7,137	$ —	$ 7,137
Cash equivalents [2]	—	69	69	—	69	69
Total assets	$ 7,472	$ 69	$ 7,541	$ 7,137	$ 69	$ 7,206

1 *This is a publicly traded balanced mutual fund. The fund seeks regular income, conservation of principal, and an opportunity for long-term growth of principal and income. The fair value is determined by taking the number of shares owned by the plan, and multiplying by the market price as of December 31, 2012.*

2 *This is a money market fund. The money market fund investments are valued at the net asset value per share of $1.00 per unit as of December 31, 2012. The money market fund invests primarily in commercial paper, notes, repurchase agreements, and other evidences of indebtedness which are payable on demand or short-term in nature.*

(13) Income Taxes

The details of income tax (benefit) expense are as follows:

Puget Energy (Dollars in Thousands)	Year Ended December 31, 2012	Year Ended December 31, 2011	Year Ended December 31, 2010
Charged to operating expenses:			
Current:			
Federal	$ 4,268	$ 785	$ 42,061
State	—	(50)	385
Deferred:			
Federal	100,701	32,706	(38,717)
State	(244)	319	(1,248)
Total income tax expense	$ 104,725	$ 33,760	$ 2,481

Puget Sound Energy	Year Ended December 31,		
(Dollars in Thousands)	2012	2011	2010
Charged to operating expenses:			
Current:			
Federal	$ 4,268	$ 653	$ 32,331
State	—	—	385
Deferred:			
Federal	145,040	76,369	(31,346)
State	—	1,095	(1,248)
Total income tax expense	$ 149,308	$ 78,117	$ 122

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

Puget Energy (Dollars in Thousands)	Year Ended December 31, 2012	Year Ended December 31, 2011	Year Ended December 31, 2010
Income taxes at the statutory rate	$ 132,491	$ 54,968	$ 11,477
Increase (decrease):			
Production tax credit	(22,188)	(23,310)	(19,972)
AFUDC excluded from taxable income	(16,543)	(22,861)	(9,970)
Capitalized interest	9,757	17,592	8,244
Utility plant differences	8,674	5,849	6,162
Tenaska gas contract	(4,687)	7,094	5,889
Other - net	(2,779)	(5,572)	651
Total income tax expense	$ 104,725	$ 33,760	$ 2,481
Effective tax rate	27.7%	21.5%	7.6%

Puget Sound Energy	Year Ended December 31,		
(Dollars in Thousands)	2012	2011	2010
Income taxes at the statutory rate	$ 176,917	$ 98,783	$ 9,176
Increase (decrease):			
Production tax credit	(22,188)	(23,310)	(19,972)
AFUDC excluded from taxable income	(16,543)	(22,861)	(9,970)
Capitalized interest	9,757	17,592	8,244
Utility plant differences	8,674	5,849	6,162
Tenaska gas contract	(4,687)	7,094	5,889
Other - net	(2,622)	(5,030)	593
Total income tax expense	$ 149,308	$ 78,117	$ 122
Effective tax rate	29.5%	27.7%	0.5%

The Company's deferred tax liability at December 31, 2012 and 2011 is composed of amounts related to the following types of temporary differences:

Puget Energy (Dollars in Thousands)	At December 31, 2012	At December 31, 2011
Utility plant and equipment	$ 1,409,216	$ 1,201,038
Regulatory asset for income taxes	119,844	62,305
Fair value of debt instruments	86,831	90,535
Other deferred tax liabilities	151,820	130,068
Subtotal deferred tax liabilities	1,767,711	1,483,946
Net operating loss carryforward	(298,440)	(165,890)
Production tax credit carryforward	(113,117)	(89,226)
Regulatory Liability on production tax credit	(59,811)	(47,864)
Fair value of derivative instruments	(44,835)	(96,374)
Other deferred tax assets	(43,309)	(33,354)
Subtotal deferred tax assets	(559,512)	(432,708)
Total	$ 1,208,199	$ 1,051,238

Puget Sound Energy (Dollars In Thousands)	At December 31, 2012	At December 31, 2011
Utility plant and equipment	$ 1,409,216	$ 1,201,038
Regulatory asset for income taxes	119,279	61,344
Storm damage		
Other deferred tax liabilities	132,304	112,485
Subtotal deferred tax liabilities	1,660,799	1,374,867
Net operating loss carryforward	(134,513)	(51,083)
Production tax credit carryforward	(113,117)	(89,226)
Regulatory Liability on production tax credit	(59,811)	(47,864)
Fair value of derivative instruments	(46,139)	(92,502)
Other deferred tax assets	(100,632)	(91,340)
Subtotal deferred tax assets	(454,212)	(372,015)
Total	$ 1,206,587	$ 1,002,852

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

Puget Energy (Dollars in Thousands)	At December 31 2012	At December 31 2011
Current deferred taxes	$ (53,437)	$ (101,934)
Non-current deferred taxes	1,261,636	1,153,172
Total	$ 1,208,199	$ 1,051,238

Puget Sound Energy (Dollars in Thousands)	At December 31 2012	At December 31 2011
Current deferred taxes	$ (68,015)	$ (112,204)
Non-current deferred taxes	1,274,602	1,115,056
Total	$ 1,206,587	$ 1,002,852

The Company calculates its deferred tax assets and liabilities under ASC 740, "Income Taxes" (ASC 740). ASC 740 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. The utilization of deferred tax assets requires sufficient taxable income in the future years. ASC 740 requires a valuation allowance on deferred tax assets when it is more likely than not that the deferred tax asset will not be realized. The Company's PTC carryforwards expire from 2026 through 2032. The Company's net operating loss carryforwards expire from 2029 through 2032.

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 ASC 740, which clarifies the accounting for uncertainty in income taxes recognized in the financial statements. ASC 740 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 challenge by the taxing authorities and taken by management to the court of last resort. Second, a tax position that meets the recognition threshold should be measured at the largest amount that has a greater than 50.0% likelihood of being sustained.

As of December 31, 2012 and 2011, 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 ASC 740 purposes, the Company has open tax years from 2006 through 2012. The Company is under audit by the IRS for tax years 2006 through 2009. The Company classifies interest as interest expense and penalties as other expense in the financial statements.

(14) Litigation

Residential Exchange

The Northwest Power Act, through the Residential Exchange Program (REP), provides access to the benefits of low-cost federal power for residential and small farm customers of regional utilities, including PSE. The program is administered by the BPA. Pursuant to agreements (including settlement agreements) between the BPA and PSE, the BPA has provided payments of REP benefits to PSE, which PSE has passed through to its residential and small farm customers in the form of electricity bill credits.

In 2007, the United States Court of Appeals for the Ninth Circuit (Ninth Circuit) ruled that REP agreements of the BPA with PSE and a number of other investor-owned utilities were inconsistent with the Northwest Power Act. Since that time, those investor-owned utilities, including PSE, the BPA and other parties have been involved in ongoing litigation at the Ninth Circuit relating to the amount of REP benefits paid to utilities, including PSE, for the fiscal year 2002 through fiscal year 2011 period and the amount of REP benefits to be paid going forward.

In July 2011, the BPA, PSE and a number of other parties entered into a settlement agreement that by its terms, if upheld in its entirety, would resolve the disputes between BPA and PSE regarding REP benefits paid for fiscal years 2002-2011 and determine REP benefits for fiscal years 2012-2028. In October 2011, certain other parties challenged BPA decisions with regard to its entering into this most recent settlement agreement. Oral argument in the Ninth Circuit on this litigation occurred on February 19, 2013. Pending disposition of this challenge, the other pending Ninth Circuit litigation regarding REP benefits has been stayed by the Ninth Circuit.

Due to the pending and ongoing proceedings, PSE is unable to reasonably estimate any amounts of REP payments either to be recovered by the BPA or to be paid for any future periods to PSE, and is unable to determine the impact, if any, these proceedings and litigation may have on PSE. However, the Company believes it is unlikely that any unfavorable outcome would have a material adverse effect on PSE because REP benefits received by PSE are passed through to PSE's residential and small farm customers.

Notice of Intent to Sue

PSE has a 50% ownership interest in Colstrip Units 1 and 2, and a 25% interest in Colstrip Units 3 and 4. On July 25, 2012, a Notice of Intent to Sue for violations of the Clean Air Act at Colstrip Steam Electric Station was sent to PSE from the Sierra Club and the Montana Environmental Information Center (MEIC). The notice, which was amended on August 30, 2012, September 27, 2012, and December 1, 2012. was addressed to the owner or managing agent of Colstrip and to the other Colstrip co-owners, including PSE. The notices allege violations of the Clean Air Act and state that the Sierra Club and MEIC will request a United States District Court to impose injunctive relief and civil penalties, require a beneficial environmental project in the areas affected by the alleged air pollution and require reimbursement of Sierra Club's and MEIC's costs of litigation and attorney's fees. Under the Clean Air Act, lawsuits cannot be filed until 60 days after the applicable notice date. PSE is evaluating the allegations set forth in the notices and cannot at this time predict the outcome of this matter.

Other Proceedings

The Company is also involved in litigation relating to claims arising out of its operations in the normal course of business. The Company has recorded reserves of $3.4 million and $3.8 million relating to these claims as of December 31, 2012 and 2011, respectively.

(15) Variable Interest Entities

In accordance with ASC 810, "Consolidation" (ASC 810), a business entity that has a controlling financial interest in a variable interest entity (VIE) should consolidate the VIE in its financial statements. A primary beneficiary of a VIE is the variable interest holder that has both the power to direct matters that significantly impact the activities of the VIE and has the obligation to absorb losses or the right to receive benefits. The Company enters into a variety of contracts for energy with other counterparties and evaluates all contracts to determine if they are variable interests. The Company's variable interests primarily arise through power purchase agreements where it is required to buy all or a majority of generation from a plant at rates set forth in the agreement.

The Company evaluated its power purchase agreements and determined it was not the primary beneficiary of any VIEs. The Company had previously disclosed two potentially significant variable interests in prior periods; both entities were qualifying facilities contracts that expired at the end of 2011. The Company requested information from the relevant entities; however, they refused to provide the necessary information, as they were not required to do so under their contracts. However, if the variable interests had been determined to be VIEs, the Company concluded it would not have been the primary beneficiary of these entities based on available information and it had no exposure to loss on these contracts. For the years ended December 31, 2011 and 2010, the Company's purchased power expense from these entities was $175.9 million and $190.3 million, respectively. The Company did not identify any variable interests during the twelve months ended December 31, 2012.

(16) Commitments and Contingencies

For the year ended December 31, 2012, approximately 17.5% of the Company's energy output was obtained at an average cost of approximately $0.018 per kilowatt hour (kWh) through long-term contracts with three of the Washington Public Utility Districts (PUDs) that own 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; therefore, PSE is required to make the payments even if power is not 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 contract lives.

The Company's expenses under these PUD contracts were as follows for the years ended December 31:

(Dollars in Thousands)	2012	2011	2010
PUD contract costs	$ 70,188	$ 81,828	$ 79,598

As of December 31, 2012, the Company was entitled to purchase portions of the power output of the PUDs' projects as set forth in the following table:

		Company's Current Share of					
(Dollars in Thousands)	Contract Expiration	Percent of Output	Megawatt Capacity	Estimated 2013 Costs	2013 Debt Service Costs	Interest included in 2013 Debt Service Costs	Debt Outstanding
Chelan County PUD:							
Rock Island Project	2031	25.0%	156	$ 28,601	$ 11,206	$ 6,635	$ 106,546
Rocky Reach Project	2031	25.0%	325	25,414	8,772	3,810	62,547
Douglas County PUD:							
Wells Project	2018	29.9%	251	15,983	8,548	3,079	76,925
Grant County PUD:							
Priest Rapids Development	2052	0.8%	9	4,043	2,220	1,247	23,967
Wanapum Development	2052	0.8%	9	4,043	2,220	1,247	23,967
Total			750	$ 78,084	$ 32,966	$ 16,018	$ 293,952

The following table summarizes the Company's estimated payment obligations for power purchases from the Columbia River projects, contracts with other utilities and contracts with non-utilities. These contracts have varying terms and may include escalation and termination provisions.

(Dollars in Thousands)	2013	2014	2015	2016	2017	Thereafter	Total
Columbia River projects	$ 65,839	$ 66,313	$ 65,425	$ 65,485	$ 65,030	$ 693,057	$ 1,021,149
Other utilities	16,928	17,646	16,983	17,230	10,453	—	79,240
Non-utility contracts	63,107	54,352	117,198	148,074	187,099	1,671,444	2,241,274
Total	$ 145,874	$ 138,311	$ 199,606	$ 230,789	$ 262,582	$ 2,364,501	$ 3,341,663

Total purchased power contracts provided the Company with approximately 6.1 million, 8.5 million and 8.2 million megawatt hours (MWh) of firm energy at a cost of approximately $203.1 million, $391.8 million and $420.6 million for the years 2012, 2011 and 2010, respectively.

The Company has natural gas-fired generation facility obligations for natural gas supply amounting to an estimated $53.4 million in 2013. Longer term agreements for natural gas supply amount to an estimated $417.8 million for 2013 through 2030.

PSE enters into short-term energy supply contracts to meet its core customer needs. These contracts are sometimes classified as NPNS, however in most cases recorded at fair value in accordance with ASC 815. Commitments under these contracts are $297.0 million, $189.6 million and $51.3 million in 2013, 2014 and 2015, respectively.

Natural Gas Supply Obligations

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 32 years, provide that the Company must pay a fixed demand charge each month, regardless of actual usage. The Company contracts for 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 to ensure service to PSE's customers and generation requirements. The Company incurred demand charges in 2012 for firm transportation service and firm storage and peaking service of $142.6 million and $6.6 million, respectively. The demand charge for firm natural gas supply was immaterial in 2012. The Company incurred demand charges in 2012 for firm transportation and firm storage service for the natural gas supply for its combustion turbines in the amount of $31.5 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 the FERC and NEB (National Energy Board) authorized rates, which are subject to change.

Demand Charge Obligations (Dollars in Thousands)	2013	2014	2015	2016	2017	Thereafter	Total
Firm transportation service	$ 160,590	$ 157,187	$ 144,036	$ 139,423	$ 136,950	$ 555,905	$ 1,294,091
Firm storage service	6,135	5,209	5,209	5,209	5,209	5,247	32,218
Total	$ 166,725	$ 162,396	$ 149,245	$ 144,632	$ 142,159	$ 561,152	$ 1,326,309

Service Contracts

The following table summarizes the Company's estimated obligations for service contracts through the terms of its existing contracts.

Service Contract Obligations (Dollars in Thousands)	2013	2014	2015	2016	2017	Thereafter	Total
Energy production service contracts [1]	$ 25,007	$ 25,602	$ 32,148	$ 10,442	$ 10,143	$ 36,364	$ 139,706
Information technology service contracts	13,345	—	—	—	—	—	13,345
Automated meter reading system [2]	20,480	21,135	21,899	14,241	103,414	—	181,169
Total	$ 58,832	$ 46,737	$ 54,047	$ 24,683	$ 113,557	$ 36,364	$ 334,220

1 *Energy production service contracts include operations and maintenance contracts on Mint Farm, Wild Horse, Goldendale electric generating facility (Goldendale), Hopkins Ridge, Frederickson 1, Sumas, Ferndale and Lower Snake River facilities.*

2 *Automated meter reading system contractual obligation is the service component of the Landis and Gyr contract.*

For information regarding PSE's environmental remediation obligations, see Note 3 Regulation and Rates.

(17) Related Party Transactions

On June 1, 2006, PSE entered into a revolving credit facility with 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 PSE's outstanding commercial paper interest rate or PSE's senior unsecured revolving credit facility. Absent such borrowings, interest is charged at one-month LIBOR plus 0.25%. At December 31, 2012 and 2011, the outstanding balance of the Note was $29.6 million and $30.0 million, respectively, and the interest rate was 0.5% and 1.6%, 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.

On June 3, 2011, Puget Energy issued $500.0 million of senior secured notes. Macquarie Capital (USA) Inc. acted as a co-manager and underwriter of this issue. Net proceeds of $484.0 million from these notes were used to repay a portion of the outstanding $782.0 million term-loan. Puget Energy's term-loan and credit facility for funding capital expenditures both were originally scheduled to mature in February 2014, and were syndicated among numerous committed banks and other financial institutions. One of these banks was Macquarie Bank Limited. On February 10, 2012, Puget Energy terminated the term loan and capital expenditure facility and replaced them with a $1.0 billion revolving credit facility. There are no related parties with commitments under the $1.0 billion revolving credit facility. Concurrent with the borrowings under the term loan and capital expenditure credit agreements, Puget Energy entered into several interest rate swap instruments to hedge volatility associated with these two loans. Two of the swap instruments were entered into with Macquarie Bank Limited with a total notional amount of $444.9 million. On June 3, 2011 Puget Energy settled one of the swaps with a notional amount of $77.4 million. On February 9, 2012, Puget Energy amended and reduced the remaining swap instrument by $67.5 million. On June 18, 2012, Puget Energy terminated and settled the remaining $300.0 million of the swap instrument with Macquarie Bank Limited.

(18) Segment Information

Puget Energy operates one business segment referred to as the regulated utility segment. 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.

Non-utility business segment includes two PSE subsidiaries and Puget Energy, and 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 which was sold in 2010. Reconciling items between segments are not significant.

Effective February 6, 2009, all merger related fair value adjustments under ASC 805, were retained in Puget Energy. Accordingly, only the financial statements of Puget Energy were adjusted to reflect the purchase accounting adjustments. Prior to the merger, the business segment financial statements for Puget Energy and PSE were the same.

Puget Energy (Dollars in Thousands)	Year Ended December 31, 2012 Regulated Utility	Other	Total
Revenue	$ 3,215,876	$ (720)	$ 3,215,156
Depreciation and amortization	393,770	1	393,771
Income tax (benefit) expense	154,805	(50,080)	104,725
Operating income	718,622	(3,087)	715,535
Interest charges, net of AFUDC	234,890	135,110	370,000
Net income	366,377	(92,556)	273,821
Total assets	11,076,350	1,725,229	12,801,579
Construction expenditures - excluding equity AFUDC	859,791	—	859,791

Puget Sound Energy (Dollars in Thousands)	Year Ended December 31, 2012 Regulated Utility	Other	Total
Revenue	$ 3,215,876	$ 383	$ 3,216,259
Depreciation and amortization	393,770	1	393,771
Income tax expense	149,731	(423)	149,308
Operating income	694,035	(1,046)	692,989
Interest charges, net of AFUDC	224,797	—	224,797
Net income	356,956	(786)	356,170
Total assets	10,555,289	38,987	10,594,276
Construction expenditures - excluding equity AFUDC	859,791	—	859,791

Puget Energy (Dollars in Thousands)	Year Ended December 31, 2011 Regulated Utility	Other	Total
Revenue	$ 3,319,105	$ (340)	$ 3,318,765
Depreciation and amortization	371,977	1	371,978
Income tax (benefit) expense	91,464	(57,704)	33,760
Operating income	477,730	(2,790)	474,940
Interest charges, net of AFUDC	210,463	131,498	341,961
Net income	228,908	(105,618)	123,290
Total assets	10,671,089	1,736,217	12,407,306
Construction expenditures - excluding equity AFUDC	976,513	—	976,513

Puget Sound Energy (Dollars in Thousands)	Year Ended December 31, 2011 Regulated Utility	Other	Total
Revenue	$ 3,319,106	$ 697	$ 3,319,803
Depreciation and amortization	371,977	1	371,978
Income tax (benefit) expense	78,451	(334)	78,117
Operating income	431,553	(510)	431,043
Interest charges, net of AFUDC	201,467	—	201,467
Net income	204,740	(620)	204,120
Total assets	10,064,859	43,284	10,108,143
Construction expenditures - excluding equity AFUDC	976,513	—	976,513

Puget Energy (Dollars in Thousands)	Year Ended December 31, 2010 Regulated Utility	Other	Total
Revenue	$ 3,121,934	$ 283	$ 3,122,217
Depreciation and amortization	364,205	1	364,206
Income tax (benefit) expense	35,905	(33,424)	2,481
Operating income	310,130	(1,896)	308,234
Interest charges, net of AFUDC	220,922	86,088	307,010
Net income	92,927	(62,616)	30,311
Total assets	10,209,207	1,748,804	11,958,011
Construction expenditures - excluding equity AFUDC	859,091	—	859,091

Puget Sound Energy (Dollars in Thousands)	Year Ended December 31, 2010 Regulated Utility	Other	Total
Revenue	$ 3,121,935	$ 282	$ 3,122,217
Depreciation and amortization	364,204	2	364,206
Income tax (benefit) expense	60	62	122
Operating income	207,647	(56)	207,591
Interest charges, net of AFUDC	220,854	—	220,854
Net income	26,358	(263)	26,095
Total assets	9,289,350	50,109	9,339,459
Construction expenditures - excluding equity AFUDC	859,091	—	859,091

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	2012 Quarter			
(Unaudited; Dollars in Thousands)	First	Second	Third	Fourth
Operating revenue	$ 1,048,512	$ 678,617	$ 578,755	$ 909,272
Operating income	209,023	159,876	153,262	193,374
Net income	88,480	57,692	46,692	80,957

(Unaudited; Dollars in Thousands)	2011 Quarter First	Second	Third	Fourth
Operating revenue	$ 1,019,593	$ 732,675	$ 597,776	$ 968,721
Operating income	218,145	114,693	20,663	121,439
Net income (loss)	107,431	5,035	(36,470)	47,294

Puget Sound Energy

(Unaudited; Dollars in Thousands)	2012 Quarter First	Second	Third	Fourth
Operating revenue	$ 1,048,512	$ 678,617	$ 579,611	$ 909,519
Operating income	201,245	153,306	150,007	188,431
Net income	112,716	80,872	66,868	95,714

(Unaudited; Dollars in Thousands)	2011 Quarter First	Second	Third	Fourth
Operating revenue	$ 1,019,593	$ 733,364	$ 597,776	$ 969,070
Operating income	190,436	107,380	17,198	116,029
Net income (loss)	103,439	50,913	(9,107)	58,875

SCHEDULE I: CONDENSED FINANCIAL INFORMATION OF PUGET ENERGY

Puget Energy

Condensed Statements of Income and Comprehensive Income (Loss)

(Dollars in Thousands)

	Year Ended December 31,		
	2012	2011	2010
Equity in earnings of subsidiary [1]	$ 365,590	$ 228,288	$ 92,700
Non-utility expense and other	(2,040)	(2,280)	(1,895)
Other income (deductions):			
Unhedged interest rate derivative expense	(4,288)	(28,601)	(7,955)
Interest income	214	215	260
Interest expense	(135,312)	(131,702)	(86,304)
Income taxes	49,657	57,370	33,505
Net income	273,821	123,290	30,311
Comprehensive income (loss)	$ 285,398	$ 148,733	$ (5,837)

1 *Equity earnings of subsidiary included earnings from PSE of $356.2 million, $204.1 million and $26.1 million for the years ended December 31, 2012, 2011 and 2010, respectively, and business combination accounting adjustments under ASC 805 recorded at Puget Energy for PSE of $9.4 million, $24.2 million and $66.6 million for the years ended December 31, 2012, 2011 and 2010, respectively.*

See accompanying notes to the consolidated financial statements.

Puget Energy
Condensed Balance Sheets
(Dollars in Thousands)

	December 31, 2012	December 31, 2011
Assets:		
Investment in subsidiaries [1]	$ 3,490,206	$ 3,314,195
Other property and investments:		
Goodwill	1,656,513	1,656,513
Current assets:		
Cash	12	6,224
Receivables from affiliates [2]	29,608	30,291
Deferred income taxes	2,300	8,824
Total current assets	31,920	45,339
Long-term assets:		
Deferred income taxes	166,896	117,110
Other	20,944	13,544
Total long-term assets	187,840	130,654
Total assets	$ 5,366,479	$ 5,146,701
Capitalization and liabilities:		
Common equity	$ 3,484,228	$ 3,300,923
Long-term debt	1,833,959	1,779,844
Total capitalization	5,318,187	5,080,767
Current liabilities:		
Account Payable	212	—
Interest	26,466	13,525
Unrealized loss on derivative instruments	6,571	25,210
Total current liabilities	33,249	38,735
Long-term liabilities:		
Unrealized loss on derivative instruments	15,043	27,199
Total long-term liabilities	15,043	27,199
Total capitalization and liabilities	$ 5,366,479	$ 5,146,701

1 *Investment in subsidiaries for successor include Puget Energy business combination accounting adjustments under ASC 805 that are recorded at Puget Energy.*

2 *Eliminated in consolidation.*

See accompanying notes to the consolidated financial statements.

Puget Energy
Condensed Statements of Cash Flows
(Dollars in Thousands)

	Year Ended December 31,		
	2012	2011	2010
Operating activities:			
Net income	$ 273,821	$ 123,290	$ 30,311
Adjustments to reconcile net income to net cash provided by (used in) operating activities:			
Unrealized gain on derivative instruments	(12,984)	33,549	(3,599)
Deferred income taxes and tax credits - net	(49,496)	(57,151)	(52,364)
Equity in earnings of subsidiary [1]	(365,590)	(228,288)	(92,700)
Other	11,409	12,837	18,169
Dividends received from subsidiaries	175,625	212,875	186,733
Accounts receivable	283	618	(891)
Income taxes	—	14,069	20,601
Accounts payable	212	—	(48)
Accrued interest	12,941	9,045	(926)
Net cash provided by (used in) operating activities	46,221	120,844	105,286
Investing activities:			
Investment in subsidiaries	—	(287,000)	—
(Increase) decrease in loan to subsidiaries	400	(7,400)	300
Net cash provided by (used in) investing activities	400	(294,400)	300
Financing activities:			
Dividends paid	(88,594)	(117,441)	(104,311)
Issuance of bond	884,000	787,000	450,000
Redemption of term-loan	(843,000)	(484,000)	(443,000)
Issue costs	(5,239)	(6,016)	(8,157)
Net cash provided by (used in) by financing activities	(52,833)	179,543	(105,468)
Increase (decrease) in cash	(6,212)	5,987	118
Cash at beginning of year	6,224	237	119
Cash at end of year	$ 12	$ 6,224	$ 237

1 *Equity earnings of subsidiary included earnings from PSE of $356.2 million and $204.1 million for the years ended December 31, 2012 and 2011, respectively, and business combination accounting adjustments under ASC 805 recorded at Puget Energy for PSE of $9.4 million and $24.2 million for the years ended December 31, 2012 and 2011, respectively.*

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, 2012				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 8,495	$ 21,567	$ 20,130	$ 9,932
Year Ended December 31, 2011				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 9,784	$ 18,449	$ 19,738	$ 8,495
Year Ended December 31, 2010				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 8,094	$ 23,875	$ 22,185	$ 9,784

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, 2012				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 8,495	$ 21,567	$ 20,130	$ 9,932
Year Ended December 31, 2011				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 9,784	$ 18,449	$ 19,738	$ 8,495
Year Ended December 31, 2010				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 8,094	$ 23,875	$ 22,185	$ 9,784

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Puget Energy

Evaluation of Disclosure Controls and Procedures

Under the supervision and with the participation of Puget Energy's management, including the President and Chief Executive Officer and Senior Vice President 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, 2012, the end of the period covered by this report. Based upon that evaluation, the President and Chief Executive Officer and Senior 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

The Company implemented a new system for income tax reporting in the quarter ended December 31, 2012. The change was not made in response to any deficiency in the Company's internal controls. There have been no other changes in Puget Energy's internal control over financial reporting during the quarter ended December 31, 2012 that have materially affected, or are reasonably likely to materially affect, Puget Energy's internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Puget Energy's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). Under the supervision and with the participation of Puget Energy's President and Chief Executive Officer and Senior Vice President 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, 2012.

Puget Energy's effectiveness of internal control over financial reporting as of December 31, 2012 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Puget Sound Energy

Evaluation of Disclosure Controls and Procedures

Under the supervision and with the participation of PSE's management, including the President and Chief Executive Officer and Senior Vice President 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, 2012, the end of the period covered by this report. Based upon that evaluation, the President and Chief Executive Officer and Senior Vice President and Chief Financial Officer of PSE concluded that these disclosure controls and procedures are effective.

Changes in Internal Control Over Financial Reporting

The Company implemented a new system for income tax reporting in the quarter ended December 31, 2012. The change was not made in response to any deficiency in the Company's internal controls. There have been no other changes in PSE's internal control over financial reporting during the quarter ended December 31, 2012 that have materially affected, or are reasonably likely to materially affect, PSE's internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

PSE's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). Under the supervision and with the participation of PSE's President and Chief Executive Officer and Senior Vice President 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, 2012.

PSE's effectiveness of internal control over financial reporting as of December 31, 2012 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

As of March 4, 2013, twelve directors constitute Puget Energy's Board of Directors and thirteen directors currently constitute PSE's Board of Directors, as set forth below. The directors are selected in accordance with the Amended and Restated Bylaws of each of Puget Energy and PSE, pursuant to which, the investor-owners of Puget Holdings (the indirect parent company of both Puget Energy and PSE) are entitled to select individuals to serve on the boards of Puget Energy and PSE.

William Ayer, age 58, is a director on the boards of both Puget Energy and PSE. Over the past 30 years, Mr. Ayer has served in a variety of leadership positions at Alaska Air Group, the parent company of Alaska Airlines and Horizon Air, where he currently serves as Chairman. Until May 2012, as the Chief Executive Officer of Alaska Airlines, Mr. Ayer led the nation's seventh-largest airline with 9,600 employees. He also oversaw regional carrier Horizon Air and its 3,200 employees. Mr. Ayer is also a member of the board of directors of the Museum of Flight and Angel Flight West and serves on the University of Washington's Board of Regents and the NextGen Advisory Committee. Mr. Ayer's experience running a successful company recognized nationally for its award-winning customer service and operational performance, coupled with his community involvement in the western Washington region, are among the qualifications and attributes that led to the conclusion that he should serve on the Puget Energy and PSE boards.

Andrew Chapman, age 57, has been a director on the boards of both Puget Energy and PSE since February 2009. Mr. Chapman is currently a director on the Board of Duquesne Light Holdings, Inc. and Duquesne Light Company, which position he has held since February 1, 2010. 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. Mr. Chapman represents the Company's Macquarie affiliated investors on the boards, in accordance with the terms of the Puget Energy and PSE bylaws, and brings to his service many years of experience in the operational and financial management challenges specific to regulated utilities.

Melanie Dressel, age 60, is a director on the boards of both Puget Energy and PSE, which positions she has held since December 2011. Ms. Dressel is currently President and Chief Executive Officer of Columbia Bank and its parent company, Columbia Banking System, Inc., of Tacoma, Washington, which positions she has held since 2000 and 2003, respectively. An independent director not affiliated with any of the Company's investors, Ms. Dressel's leadership skills, financial experience and many ties to civic and community groups in the Company's service territory are among the reasons for her appointment to the Puget Energy and PSE boards.

Daniel Fetter, age 36, is a director on the boards of both Puget Energy and PSE, which positions he has held since August 2, 2012. Mr. Fetter is currently the Senior Principal, Private Infrastructure with Canada Pension Plan Investment Board (CPPIB), which position he has held since 2009. Prior to that, Mr. Fetter served as both a Principal (from 2007 to 2009) and Associate (from 2006 to 2007) at CPP Investment Board. Mr. Fetter is currently on the Board of Directors of Arqiva, a communications infrastructure and media services company, which position he has held since 2009. Mr. Fetter serves on the boards of Puget Energy and PSE as a representative of CPPIB's ownership interests, pursuant to the terms of the Puget Energy and PSE bylaws, and brings to this service his skills in financial management of infrastructure providers.

Kimberly Harris, age 48, is a director on the boards of both Puget Energy and PSE, which positions she has held since March 1, 2011. Ms. Harris has also been President and Chief Executive Officer since March 1, 2011. Prior to that time, Ms. Harris served as President from July 2010 through February 2011. Ms. Harris also served as Executive Vice President and Chief Resource Officer from May 2007 until July 2010, and was Senior Vice President Regulatory Policy and Energy Efficiency from 2005 until May 2007.

Benjamin Hawkins, age 38, has been a director on the boards of both Puget Energy and PSE since May 21, 2010. Mr. Hawkins is currently a Senior Principal of Infrastructure & Timber Investments for Alberta Investment Management Corporation (AimCo), which position he has held since June 2011. Mr. Hawkins also served as Principal of Infrastructure Investments of AimCo from November 2008 until June 2011, and Portfolio Manager of Infrastructure Investments from May of 2007 until November 2008. Prior to joining AimCo, Mr. Hawkins held various positions with EPCOR Utilities, a Canadian power and water utility company. Mr. Hawkins serves on the boards as a representative of AimCo's ownership interest in the Company, pursuant to the terms of the Puget Energy and PSE bylaws, and brings to this service his skills in financial oversight of utilities.

Alan James, age 59, has been a director on the boards of both Puget Energy and PSE since February 2009, as a representative of the Company's Macquarie affiliated investors consistent with the Puget Energy and PSE bylaws. Mr. James is currently the Chairman and Senior Managing Director of Macquarie Capital (USA) Inc. based in New York where he specializes in providing M&A advice and capital raising solutions to the utility, power and renewable sectors in North America, 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 and held various positions with Deutsche Bank AG in Australia and Europe from 1993 to 2002 specializing in the energy sector. Mr. James provides the boards the benefit of his broad experience with the financial needs and operational and regulatory challenges of infrastructure providers.

Christopher Leslie, age 48, has been a director on the boards of both Puget Energy and PSE since February 2009, as a representative of the Company's Macquarie affiliated investors consistent with the Puget Energy and PSE bylaws. Mr. Leslie is currently an Executive Director of Macquarie Group Limited, which position he has held since 2005, President of Macquarie Infrastructure and Real Assets Inc., and since 2006 Chief Executive Officer of Macquarie Infrastructure Partners Inc. Mr. Leslie served as a director on the boards of Duquesne Light Holdings, Inc. and Duquesne Light Company in 2009 and 2010. In addition to his management and banking skills, Mr. Leslie provides the Puget Energy and PSE boards the benefit of his experience with electric utilities, gas distribution systems and other aspects of the infrastructure sector.

David MacMillan, age 60, has been a director on the boards of both Puget Energy and PSE since November 6, 2012. Mr. MacMillan currently is a non-executive director of Viridian Group Ltd., an energy company based in Northern Ireland, and serves on the board of Potentia Solar Inc., a Toronto-based independent solar-power producer. He has also served as managing director and senior advisor to Good Energies Capital (now named Bregal Energy), a New York-based private equity fund focused on the renewable energy sector, which positions he held from 2007 to 2010, non-executive director of Ontario Power Generation (from 2004 to 2012) and Intergen (from 2006 to 2008). Mr. MacMillan serves on the boards of Puget Energy and PSE as a representative of CPPIB's ownership interests, pursuant to the terms of the Puget Energy and PSE bylaws, and brings to this service his skills in project finance and experience with managing the capital requirements of energy companies.

John McMahon, age 61, has been a director on the boards of both Puget Energy and PSE since May 8, 2012. Through December 31, 2012, Mr. McMahon served as independent chairman of Presidential Life Corporation and senior adviser to Macquarie Infrastructure and Real Assets. Mr. McMahon also serves on the boards of DQE Holdings LLC and its subsidiaries, including Duquesne Light, a regulated utility in Pittsburgh. From February 2009 to January 31, 2011 Mr. McMahon was Executive Vice President of Con Edison Inc, a regulatory utility company in New York, and was responsible for regulatory affairs, energy policy, energy efficiency and legal affairs. From 2003 to 2009 he was President and Chief Executive Officer of Orange and Rockland Utilities, Inc. Prior to that he served as general counsel for Con Edison. Mr. McMahon serves on the boards of Puget Energy and PSE as a representative of the Company's Macquarie affiliated investors consistent with the Puget Energy and PSE bylaws, and provides the Puget Energy and PSE boards the benefit of his experience managing and overseeing the legal, regulatory and operational affairs of regulated utilities.

Mary McWilliams, age 64, has been a director on the boards of both Puget Energy and PSE since March 1, 2011. Ms. McWilliams is currently the Executive Director at Puget Sound Health Alliance, which position she has held since 2008. She also served as President and Chief Executive Officer at Regence BlueShield from 2000 to 2008. In addition, Ms. McWilliams serves as Chairman of the board of the Seattle Branch of the Federal Reserve Bank of San Francisco. Ms. McWilliams's significant experience managing consumer-focused organizations with challenging regulatory and compliance regimes, as well as her extensive knowledge of the western Washington economy generally, are some of the reasons that led to her appointment to the Puget Energy and PSE boards on behalf of the CPPIB.

Herbert Simon, age 69, is a director on the board of PSE, on which he has served since March 2006. 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. In addition, Mr. Simon serves as a Regent at the University of Washington and as a Board member of Acre, the real estate committee for the University of Washington. Mr. Simon previously served on the Advisory Boards of the University of Washington at Tacoma and its Institute of Technology. An independent director not affiliated with any of the Company's investors, Mr. Simon's long-standing involvement with the commercial, educational, political and philanthropic leadership of western Washington are among the qualifications supporting his appointment to the PSE board.

Christopher Trumpy, age 58, has been a director on the boards of both Puget Energy and PSE since January 12, 2010. Mr. Trumpy is currently the Chairman of the Pacific Carbon Trust, which position he has held since 2008. He also served as Chairman of the British Columbia Investment Management Corporation (or bcIMC) from 2000 to 2008. In addition, Mr. Trumpy served as Deputy Minister at Ministries of Finance, Environment and Provincial Revenue from 1998 to 2009. Mr. Trumpy represents the ownership stake in the Company of bcIMC, in accordance with the terms of the Puget Energy and PSE bylaws, and provides the boards the benefit of his significant leadership roles in government and policy-making, among other attributes.

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, Melanie Dressel, Benjamin Hawkins, David MacMillan, John McMahon and William Ayer are the members of the Audit Committee. The Board has determined that Andrew Chapman meets the definition of "Audit Committee Financial Expert" under SEC rules. 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.

Additional Information

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

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.

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 Committee (referred to as the Committee) of the Boards of Directors (referred to as the Board) of Puget Energy and PSE (referred to as the Company) are named in the Compensation and Leadership Development Committee Report. No members of the Committee were officers or employees of the Company or any of its subsidiaries during 2012, were formerly Company officers or had any relationship otherwise requiring disclosure. Each member meets the independence requirements of the SEC and the New York Stock Exchange (NYSE).

Compensation Discussion and Analysis

This section provides information about the compensation program for the Company's Named Executive Officers who are included in the Summary Compensation Table. For 2012, the Company's Named Executive Officers and titles were:

- Kimberly J. Harris, President and Chief Executive Officer (CEO);
- Daniel A. Doyle, Senior Vice President and Chief Financial Officer (CFO);
- Susan McLain, Senior Vice President, Delivery Operations;
- Paul M. Wiegand, Senior Vice President, Energy Operations; and
- Marla D. Mellies, Senior Vice President, Chief Administrative Officer;

This section also 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 attracting, retaining and motivating talented people to run the business.

- Align compensation payment levels with achievement of Company goals.

The Committee is responsible for developing and monitoring an executive compensation program and philosophy that achieves the foregoing objectives. In performing its duties, the Committee obtains information and advice on various aspects of its executive compensation program from its independent executive compensation consultant, Frederic W. Cook & Co., Inc. (Cook & Co.). The Committee recommends the salary level for our CEO, based on information provided by Cook & Co., and recommends the salary levels for the other executives, based on recommendations from our CEO, to the full Board for approval. The Committee also recommends to the Board for its approval of the annual and long-term incentive compensation plans for the executives, the setting of performance goals and the determination of awards under those plans.

In 2012, the Committee used the following strategies to achieve the objectives of our executive compensation program:

- *Design and deliver a competitive total pay opportunity.* To attract, retain and motivate a talented executive team, the Committee believes that total pay opportunity should be competitive with similar companies so that new executives will want to join the Company and current executives will be retained. As described below in the discussion of Compensation Program Elements (Review of Pay Element Competitiveness), the Committee annually compares executive compensation to external market data from similar companies in our industry and targets base salary and total direct compensation (which is base salary plus annual and long-term incentive compensation) to the 50th percentile of this comparator group. The Committee also recognizes the importance of providing retirement income. Executives choose to work for the Company as opposed to 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 our comparator group and provides benefits that are commensurate with this group.
- *Place a significant portion of each executive's total compensation at risk to align executive compensation with Company financial and operating performance.* Under its "pay for performance" philosophy, the Committee works to design and deliver an incentive compensation program that supports the Company's business direction as approved by the Board and aligns executive interests with those of investors and customers. The Committee believes that a significant portion of each executive's compensation should be "at risk" and rewarded solely for meeting and exceeding target levels of annual and long-term performance goals. By establishing goals, monitoring results, and rewarding achievement of goals, the Company focuses executives on actions that will improve the Company and enhance investor value, while also retaining key talent. The Committee annually evaluates the performance factors and targets for our annual and long-term incentive programs and considers adjustments as appropriate to meet the objectives of our executive compensation program. As described under "Risk Assessment," the Company's policies and practices surrounding incentive pay are structured in a manner to mitigate the risk that employees would seek to take untoward risks in an attempt to increase incentive results.
- *Execute the Company's succession planning process to ensure that executive leadership continues uninterrupted by executive retirements or other personnel changes.* The CEO leads the talent reviews for leadership succession planning through meetings with her executive team. Each executive conducts talent reviews of senior employees that report to him or her and 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 and the Board annually review these assessments of executive readiness, the plans for development of the Company's key executives, and progress made on these succession plans. The Committee and the Board directly participate in discussion of succession plans for the position of CEO.

Compensation Program Elements

The Company's compensation program encompasses a mix of base salary, annual and long-term incentive compensation, retirement programs, health and welfare benefits and a limited number of perquisites. The Company also provides certain post-termination and change in control benefits to executives who were employed by the Company prior to March 2009. Since the Company is no longer publicly listed following its merger in February 2009 and no longer grants equity awards to its executives, it relies on a mix of non-equity compensation elements to achieve its compensation objectives.

The total compensation package is designed to provide participants with appropriate incentives that are competitive with the comparator group and is also designed to 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 compensation elements, although long-term incentive programs are designed to comprise the largest portion of each executive's incentive pay. The Company arrives at a mix of pay by setting each compensation element relative to market comparators. The Company delivered cash compensation to the Named Executive Officers in 2012 through base salary to provide liquidity for the executives and through incentive programs to focus performance on important Company goals and to increase the alignment with investors. The Committee annually reviews total compensation opportunity and actual total compensation received over the prior years by each executive 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, annual incentive programs and long-term incentive programs, management prepares comprehensive compensation surveys for review by the Committee and Cook & Co. The surveys summarize data provided by the Towers Watson 2011 Energy Services survey for a selection of utility and other companies that are most similar in scope and size to PSE. For the review of compensation pay levels and practices in 2012, 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 — $12.0 billion asset size) and also participated in the Towers Watson 2011 Energy Services survey:

1.	AGL Resources	8.	Northeast Utilities	15.	SCANA
2.	Alliant Energy	9.	NSTAR	16.	Southern Union Company
3.	Avista	10.	NV Energy	17.	Teco Energy
4.	CMS Energy Group	11.	OGE Energy	18.	Westar Energy
5.	MDU Resources	12.	Pinnacle West Capital	19.	Wisconsin Energy
6.	New York Power Authority	13.	PNM Resources		
7.	Nicor	14.	Portland General Electric		

Base pay and total direct compensation (which is base salary plus annual and long-term incentive compensation) are targeted to the 50th percentile of the industry comparator group assuming the Company's performance goals are achieved at target. If Company performance results are below expectations, total direct compensation is lower than this targeted level. If Company performance significantly exceeds target, total cash compensation can approach or exceed the 75th percentile of the industry comparator group.

Individual pay adjustments are reviewed to see how they position the executive in relation to the 50th percentile of market pay, while also considering the executive's recent performance and experience level. The Company may choose to pay an executive above or below the 50th percentile of market pay when that individual 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 addition to the foregoing survey data, the Committee also received advice from Cook & Co. in connection with 2012 compensation decisions.

Base Salary

We recognize that it is necessary to provide executives with a fixed amount of total compensation that is delivered each month and provides a balance to other pay elements that are at risk. Base salaries are generally targeted at the 50th percentile of the comparator group and are reviewed annually by the Committee on an individual basis using as a guideline, the 50th percentile salary levels of our comparator group, as well as internal pay equity among our executives. Actual salaries vary by individual and depend on additional factors, such as an individual's expertise, level of performance achievement, level of experience and level of contribution relative to others in the organization.

Base Salary Adjustments

The Committee reviewed the base salaries of the Named Executive Officers in early 2012 and recommended base salary adjustments to the Board. The Board approved the Committee's recommendation to increase executive salaries, and base salaries for 2012 generally remained at the 50th percentile of market among the comparator group. Effective March 1, 2012, the Board increased the base salary of Ms. Harris, President and CEO, from $720,000 to $820,000. In establishing the salary amount for Ms. Harris, the Committee recommended and the Board approved a base salary that continued to be below the 50th percentile of market among the comparator group, reflecting Ms. Harris's recent tenure as President and CEO of the Company. The salary increase percentages approved by the Board for the other Named Executive Officers were in a range of 2% to 5%, similar to salary increases for other non-represented employees, except for Mr. Doyle who joined the Company on November 18, 2011 and did not receive a salary increase in 2012.

Incentive Compensation (Annual and Long-Term)

Our annual and long-term incentive plan (LTI Plan) help focus executives on the priorities of our investors and customers and reward performance that meets or exceeds pre-established goals. The Company's annual incentive plan rewards employees for the Company's performance on Service Quality Indices (SQIs), employee safety and EBITDA. SQIs were developed in collaboration with the Company's regulator, the Washington Commission, and provide customers with a report card on the Company's customer service and reliability. The Company's LTI Plan rewards employees for the Company's performance on Total Return and Return on Equity (ROE). The performance measures of EBITDA, Total Return, and ROE are indicators of economic return to our investors, and their accomplishment indicates to our customers that the Company has the financial strength needed for long-term sustainability.

2012 Annual Incentive Compensation

All PSE employees, including the Named Executive Officers, are eligible to 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, measured by EBITDA, while also meeting the Company's service quality commitment to customers and an employee safety measure. EBITDA was selected as a performance goal because it provides a financial measure of cash flows generated from the Company's annual operating performance.

For 2012, the Company's service quality commitment was measured by performance against 9 SQIs covering three broad categories, set forth below. These are the same SQIs for which the Company is accountable to the Washington Commission. The Company's annual report to the Washington Commission and our customers describes each SQI, how it is measured, the Company's required level of achievement, and performance results. The Company's service quality report cards are available at http://www.PSE.com/PerformanceReportCards.

The SQIs for 2012 were as follows:

- **Customer Satisfaction (3 SQIs)**
  - Customer satisfaction with the telephone access center and gas field services and number of Washington Commission complaints
- **Customer Service (2 SQIs)**
  - Calls answered "live" and on-time appointments
- **Safety and Reliability (4 SQIs)**
  - Gas emergency response, electric emergency response, non-storm outage frequency and non-storm outage duration

In 2012, to emphasize the Company's continued commitment to employee safety, the Company added a new safety performance measure to the annual incentive plan funding in addition to the SQIs and EBITDA. The employee safety measure functions similarly to the 9 SQIs in determining the funding of the annual incentive plan. That is, if the safety measure is not achieved, annual incentive funding will be decreased by 10%, in the same way as a missed SQI. The safety performance measure contains five targets which must all be satisfied for the safety measure to be treated as met. The five targets are:

- Frontline supervisors receive appropriate safety and health training.
- New employees receive applicable safety and health orientation.
- Actively reduce the risk of ergonomic office injuries.
- Reduce the Company Total Incident Case Rate (TICR) by 4% of the year end 2011 TICR.
- Reduce the Company Lost Workday Case Rate (LWCR) by 15% of the year end 2011 LWCR.

In 2012, the annual incentive funding table required achievement of 10 out of 10 customer service and safety measures (all 9 SQIs and achievement of the safety measure) and target EBITDA performance for 100% funding of the plan. Funding levels at maximum, target, and threshold are shown in the table below.

Annual Incentive Performance Payout Scale and Actual Performance

Performance	2012 EBITDA (In Millions)	SQI & Safety*	Funding Level
Maximum	$ 1,454.0	10/10	200%
Target	1,077.0	10/10	100%
Threshold Payout Funding	969.3	6/10	35%
2012 Actual Performance	$ 1,101.3	10/10	111.3%

* Combined SQI & Safety results of 6/10 or better and minimum EBITDA of $969.3 million are required for any annual incentive payout funding. SQI/Safety results below 10/10 reduce funding (e.g., 9/10 = 90%, 8/10 = 80%, 7/10 = 70%).

The Committee can adjust EBITDA used in the annual incentive calculation to exclude nonrecurring items that are outside the normal course of business for the year, but did not exclude any items for 2012. Individual awards may be adjusted upward or downward based on a subjective evaluation of an executive officer's performance against individual and team goals. Individual goals were developed from the overall corporate goals for 2012, set forth below:

2011 Corporate Goals

- **Take Safety to the People** -Engage our customers and the general public in safety, extending our Nobody Gets Hurt Today program beyond our employees and service providers in order to better serve our community and region while reinforcing our internal commitment to safety.
- **Deliver the Big S Projects** - Ensure a seamless transition to the successful deployment of the Geospatial Information System (GIS), Outage Management System (OMS) and Customer Information System (CIS) in order to provide greater dependability, improved customer service and more efficient use of customer dollars.
- **Watch the Dollars** - Serve our customers and achieve our 2012-2016 plan goals through prioritizing our work around those activities that drive the safe, dependable and efficient delivery of electricity and natural gas.

2012 Annual Incentive Plan Results

Achievement of the corporate goals for 2012 was above target for EBITDA, and at target for SQI and safety achievement. PSE EBITDA was $1,101.3 million, and SQI and safety achievement was 10 out of 10, leading to a funding level for 2012 of 111.28% under the annual incentive plan.

For 2012, individual target incentive levels for this plan varied by executive officer as a percentage of 2012 base salary as shown in the table below, based on the individual executive's level of responsibility within the Company. Target annual incentive opportunities as a percentage of base salary for participating executives remained unchanged from 2011 levels except for Mr. Doyle who was not eligible to participate in the 2011 annual incentive plan. The maximum incentive for exceptional performance in this plan is twice the target incentive. As described above, an executive's individual award amount can be increased or decreased based on a subjective assessment by the CEO (or the Board in the case of the CEO) of the executive's individual and team performance results. After considering performance on individual and team goals, which were determined to be met or exceeded by each executive, small adjustments were made by the CEO for individual performance of the Named Executive Officers below CEO in 2012 and the following amounts were approved by the Board and paid at the amounts as shown below. The adjustments for individual performance did not materially change amounts from the formula amount of 111.28% of target. The Committee similarly recommended an award amount for the CEO which included a small adjustment for individual performance in 2012 and to recognize that the Company exceeded 2012 annual incentive goals. The Board approved the amounts shown below, which were paid in March 2013.

Name	Target Incentive (% of Base Salary)	2012 Actual Incentive Paid	2012 Actual Incentive (% of Base Salary)
Kimberly J. Harris	85%	$ 820,000	100%
Daniel A. Doyle	45%	247,876	55%
Susan McLain	45%	144,096	48%
Paul M. Wiegand	45%	151,903	53%
Marla D. Mellies	45%	143,543	53%

Long-Term Incentive Compensation

Long-term incentive compensation opportunities are designed to be competitive with market practices, reward long-term performance and promote retention. Prior to completion of our merger in February 2009, executives received equity awards under the Puget Energy 2005 LTI Plan in the form of performance shares and performance-based restricted stock. Awards generally vested based on the Company achieving a targeted level of performance during a three-year performance cycle. Following our merger, the Company has continued the basic design of the pre-merger LTI Plan, including retention of three-year performance cycles that begin each year. Since the Company no longer grants equity awards to its employees, LTI Plan awards are now denominated in units and are settled in cash if threshold performance measures are met.

The Committee determines the number of LTI Plan units granted to 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 does not consider previously granted awards or the level of accrued value from prior or other programs when granting annual incentive awards or making new LTI Plan 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.

The total amount payable for a performance cycle is calculated at the end of the performance cycle based on the actual level of achievement of the performance measures as well as the per unit dollar value at the end of the performance cycle. Unit value is measured at the Puget Holdings level and is re-calculated each year based on the change in Total Return for the prior year as measured by an independent auditing firm. Total Return reflects the annual change in the value of the Company plus any distributions made to investors. Executives generally must be employed on the payment date to receive a cash payment under the LTI Plan, except in the event of retirement at normal retirement age or approved early retirement, disability or death.

The tables and points below summarize the performance measures and design of the LTI Plan grants for the performance cycles indicated below.

Grant Cycle	Total Return Component	SQI Component	ROE Component (New in 2012)
2012-2014	50%		50%
2011-2013*	50%**	50%	
2010-2012*	50%**	50%	

* *CEO grants are split 30% SQI Component and 70% Total Return Component.*

** *Total Return Component is determined based on a combination of Total Return and 3-year average SQI results.*

Long-Term Incentive Plan Performance Measures for 2012-2014

As described above, the LTI Plan structure from 2009 through 2011 maintained the basic design which had been in place prior to the Company's merger in 2009. Effective with the 2012-2014 LTI Plan grants, the Board approved certain modifications to the performance measures under the LTI Plan. Pursuant to these modifications, SQI achievement has been removed as a performance measure from the 2012-2014 performance cycle in favor of a new performance measures, Return on Equity (ROE). Total Return remains a second key performance measure under the 2012-2014 performance cycle, consistent with prior performance cycles under the LTI Plan. SQI achievement was removed to make the plan easier to understand and to remove the duplication of awards based on SQI performance, since SQI performance is already a performance measure under the annual incentive plan. As a result of the modifications, both LTI Plan performance measures for the 2012-2014 performance cycle are financial in nature and each is weighted 50%. The Board modified the performance measures and related levels of achievement percentages that trigger payouts in order to ensure that the LTI Plan continues to be viewed as an incentive by the participants and aligns the interests of participants with the long-term success of the Company. Other aspects of the program, such as three-year performance cycles and the target levels of grants (as a percentage of annual base salary at the time of grant), remain unchanged from the 2011-2013 performance cycle.

The Board felt that ROE was an appropriate measure to add to the LTI Plan, since Company management has been tracking ROE and seeking to improve Company results on this measure. The ROE performance is measured each year by comparing actual ROE to the approved financial plan's ROE for that year. The average of each year during the three-year performance cycle will determine the final ROE award. With the implementation of solely financial performance measures, the President and CEO position received grants of LTI Plan units with a 50%/50% split between Total Return and ROE, like all other LTI Plan participants.

Target LTI Plan awards for the 2012-2014 performance cycle were calculated based on a percentage of an executive's annual base salary, taking into account the executive's level of responsibility within the Company. Target LTI Plan awards for the 2012-2014 performance cycle were 170% of base salary for Ms. Harris; 95% for Mr. Doyle, Ms. McLain, Mr. Wiegand and Ms. Mellies, which percentages were unchanged from amounts established for the 2011-2013 performance cycle. The total number of LTI Plan units granted to a Named Executive Officer for the 2012-2014 performance cycle is equal to the applicable percentage of salary (converted to dollars) divided by the per unit value at the beginning of the performance cycle, which was $36.03. The maximum incentive payable if exceptional performance is achieved on both performance measures for the LTI Plan is twice the target LTI Plan award. Details of the number of units granted and expected value can be found in the "2012 Grants of Plan-Based Awards" table below.

Long Term Incentive Plan Performance Measures for 2010-2012 and 2011-2013

With respect to the 2010-2012 and 2011-2013 performance cycles, except for the CEO, 50% of each grant of LTI Plan units is allocated to achievement of SQIs only (SQI component) and 50% is allocated to achievement of a combination of SQIs and Total Return (Total Return component). The CEO's LTI Plan units are allocated 30% to the SQI component and 70% to the Total Return component to place additional weight on financial measures, consistent with our comparator group companies. The total number of LTI Plan units granted to a Named Executive Officer is equal to the applicable percentage of salary (converted to dollars) divided by the per unit value at the beginning of the performance cycle. For the 2011-2013 performance cycle, the initial per unit value was $33.80.

The total amount payable for a performance cycle is calculated at the end of the performance cycle based on the actual level of achievement of SQIs and Total Return as well as the per unit dollar value at the end of the performance cycle. For any award to be earned in the 2010-2012 performance cycle or the 2011-2013 performance cycle, average SQI results must meet or exceed 80% accomplishment of the applicable SQIs.

The table below shows the percentage of LTI Plan target awards that will be earned based on three-year average SQI achievement.

Service Quality Indices (SQIs) Component Table

SQI Result, 3 year average	Percentage of LTI Plan Target Award
80% achievement or above	100%
Below 80%	0%

The table below shows the percentage of LTI Plan target awards under the Total Return Component that will be earned based on three-year performance. Percentages will be interpolated if performance falls between the values shown below.

Total Return Component Table

Percentage of LTI Plan Target Award

Annualized 3 Year Return	100% SQI (3 year average)	90% SQI (3 year average)	80% SQI (3 year average)	<80% SQI (3 year average)
15% or more	210%	175%	155%	0%
14%	180%	150%	130%	0%
13%	150%	125%	105%	0%
12%	120%	100%	80%	0%
11%	80%	65%	50%	0%
10%	40%	30%	20%	0%
<10%	0%	0%	0%	0%

SQI Component (50%):

- A target number of units are granted under this component at the beginning of a three-year performance cycle that will be paid in cash to the participant if the Company achieves the targeted level of 80% of SQIs during the performance cycle. The actual award is paid at target level if an average of at least 80% of SQIs are satisfied during the performance cycle, but is not paid if the average is below 80%. If targeted SQI performance is met, the amount payable is equal to the product of the target number of units granted under this component and the per unit value at the end of the performance cycle.
- If 80% of SQIs are met during the performance cycle, but the Total Return threshold of 10% is not met, the SQI component will still be paid at target.

Total Return Component (50%):

- A target number of units are granted under this component at the beginning of a three-year performance cycle that will be paid in cash to the participant if the Company achieves the targeted level of Total Return and SQI 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 of 10% for Total Return (based on average Total Return over the performance cycle) and average SQI achievement of 80%.
- The LTI Plan unit value is determined annually by applying the Total Return for each year to the prior year's unit price.
- At the completion of the performance cycle, if the Total Return component is paid, the participant receives a cash payment equal to the number of units earned under this component based on performance during the performance cycle multiplied by the unit price at the end of the performance cycle.
- If the Total Return component exceeds 10% annualized 3-year return, but the SQI threshold is not met, the Total Return component will not be paid.

LTI Plan Performance of Outstanding Awards

2012-2014 Performance Cycle:

- Award calculation is based on the full three-year performance cycle, so no award payment calculations will be made until after 2014.
- Performance on the Total Return component during 2012 below the three-year average threshold needed for payment.

- Performance on the ROE component for 2012 was above the target level. This result will be one of the three annual ROE results averaged at the end of the performance cycle.

2011-2013 Performance Cycle:

- Award calculation is based on the full three-year performance cycle, so no award payment calculations will be made until after 2013.
- Performance on the SQI component was at 9 out of 9 for both 2011 and 2012, which if continued for the remaining year of the performance cycle would mean that the SQI component would pay based on the target number of units granted to a Named Executive Officer.
- Performance on the Total Return component during 2012 and 2011 has been a combined two-year average which is below the three-year average threshold needed for payment.

2010-2012 Performance Cycle:

The 2010-2012 performance cycle has now ended and had the performance described below. Amounts payable as a result of award vesting are shown in the table below.

- Performance on the SQI component of the grant was 9 out of 9 in 2010 and 2011, and 10/10 for 2012, for a combined three-year result of 100%, which qualified for payment of the SQI component based on the target number of units granted to a Named Executive Officer.
- Performance on the Total Return component for the combined three-year average was a compounded annual rate of 4.8%, below the three-year average threshold needed for payment.

Name	Target Incentive (% of Base Salary) [1]	Total Return Component Units Granted/Paid	SQI Component Units Granted/Paid	2010-2012 Actual LTIP Paid [2]
Kimberly J. Harris	110%	12,294/0	12,294/12,294	$ 446,518
Daniel A. Doyle	95%, Pro-rated at hire	2,235/0	2,235/2,235	81,175
Susan McLain	95%	4,284/0	4,284/4,284	155,595
Paul M. Wiegand	50%	3,913/0	3,913/3,913	142,120
Marla D. Mellies	50%	2,312/0	2,312/2,312	83,972

1 Target *LTI Plan Incentive is a percentage of 2010 base salary when the grants were made in 2010.*

2 *2010-2012 Actual LTI Plan amount payable is unit price $36.32 multiplied by SQI Component units. The Total Return Component Units did not meet minimum performance threshold for payment*

Retirement Plans — SERP and Retirement Plan

The Company maintains the Supplemental Executive Retirement Plan (SERP) to attract and retain executives by providing a benefit that is coordinated with the tax-qualified Retirement Plan for Employees of PSE (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 participate in the SERP. The Committee reviewed the SERP plan during 2012 with input from Cook & Co. and modified the plan design to ensure alignment with competitive practices and with the retention goals of the program. The plan changes were effective January 1, 2013 and include a requirement that new participants reach age 55 in order to vest in accrued benefits (in addition to existing vesting requirements) and a revision to the calculation of highest average earnings to require the use of three consecutive years of eligible compensation in the last ten years of service. The plan changes do not increase the expected cost of the SERP program, and in certain instances would decrease program costs. Additional information regarding the SERP and the Retirement Plan is shown in the "2012 Pension Benefits" table.

Deferred Compensation Plan

The Named Executive Officers are eligible to participate in the Deferred Compensation Plan for Key Employees (Deferred Compensation Plan). The Deferred Compensation Plan provides eligible executives an opportunity to defer up to 100% of base salary, annual incentive bonuses and LTI Plan awards, plus receive additional Company contributions made by PSE into an account that has three investment tracking fund choices. The funds mirror performance in major asset classes of bonds, stocks, and an interest crediting fund that changes rates quarterly. Prior to 2012, the interest crediting fund was based on corporate bond rates, but effective for deferrals after December 31, 2011, it is based on a money market rate. 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 as a percentage of eligible compensation. 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. Additional information regarding the Deferred Compensation Plan is shown in the "2012 Nonqualified Deferred Compensation" table.

Post-Termination Benefits

Effective March 30, 2009, the Company entered into Executive Employment Agreements with the Named Executive Officers, except Mr. Doyle (who was not then employed by the Company), which amended and restated then existing Amended and Restated Change of Control Agreements between the Company and each of the executives. The Executive Employment Agreements provided for an employment period of two years following the February 6, 2009 completion of the merger and otherwise generally provide benefits similar to those under the previous Change of Control Agreements. Since the 2009 merger, the Company has ceased entering into these agreements with new executive officers.

The Company entered into these agreements 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 termination of employment following a change in control after they join the company. Second, the Company provided these agreements so that executives are focused on the Company's ongoing operations and are 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 and severance arrangements for the comparator group. Based on this information, the Committee believes that the arrangements generally provide benefits that are similar to those of the comparator group for longer tenured executives, but is not extending them to newly hired executives.

The "Potential Payments Upon Termination or Change in Control" section describes the current post-termination arrangements with the Named Executive Officers as well as other plans and arrangements that would provide benefits on termination of employment or a change in control, and the estimated potential incremental payments upon a termination of employment or change in control based on an assumed termination or change in control date of December 30, 2012, the last business day of 2012.

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 limited perquisites targeted to competitive practices. The Company may provide payments upon hiring a new executive to help offset the executive's relocation expenses, a practice needed to attract qualified candidates from other areas of the country. The current executives participate in the same group health and welfare plans as other employees. Company vice presidents and above, including the Named Executive Officers, are eligible for additional disability and life insurance benefits. The executives are also eligible to receive reimbursement for financial planning, tax preparation, legal services, business club memberships and executive physicals up to an annual limit. 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. These perquisites generally do not make up a significant portion of executive compensation and do not exceed $10,000 in total for each Named Executive Officer in 2012.

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 LTI Plan payments in the calculation of qualified retirement (pension and 401 (k)) and SERP benefits.

Impact of Accounting 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.

Risk Assessment

A portion of each executive's total direct compensation is variable, at risk and tied to the Company's financial and operational performance to motivate and reward executives for achievement of Company goals. The Company's variable pay program helps focus executives on interests important to the Company and its investors and customers and creates a record of their results. In structuring its incentive programs, the Company also strives to balance and moderate risk to the Company from such programs: individual award opportunities are defined and subject to limits, goal funding is based on collective company performance, annual incentive awards are balanced by long-term incentive awards that measure performance over three years, performance targets are based on management's operating plan (which includes providing good customer service), and all incentive awards to individual executives are subject to discretionary review by management, the Committee and/or the Board. As a result, the Committee and the Board believe that the programs' design do not have risks that are reasonably likely to have a material adverse effect on the Company and also provide appropriate incentive opportunities for executives to achieve Company goals that support the interests of our investors and customers.

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. Each member of the Committee served during all of 2012, except as noted below.

The Committee members listed below 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 Board, and the 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, 2012 for filing with the SEC.

Compensation and Leadership
Development Committee of
Puget Energy, Inc.
Puget Sound Energy, Inc.

Christopher Trumpy, member throughout 2012, Chair as of January 2013
Daniel Fetter, member as of August 2012
Christopher Leslie
Mary McWilliams, member as of January 2012
Herbert B. Simon (PSE Only)

SUMMARY COMPENSATION TABLE

The following information is furnished for the year ended December 31, 2012 (and for prior years where applicable) with respect to the Named Executive Officers during 2012. The positions listed below are at Puget Energy and PSE, except that Ms. McLain, Mr. Wiegand, and Ms. Mellies are executives of PSE only. Positions listed are those held by the Named Executive Officers as of December 31, 2012. Salary and incentive compensation includes amounts deferred at the executive's election.

Name and Principal Position	Year	Salary	Bonus	Stock Awards	Option Awards	Non-Equity Incentive Plan Compensation [1]	Change in Pension Value and Nonqualified Deferred Compensation Earnings [2]	All Other Compensation [3]	Total
Kimberly J. Harris	2012	$ 799,365	$ 44,378	$ --	$ --	$ 1,222,140	$ 1,725,380	$ 24,974	$ 3,816,237
President and Chief	2011	711,833	--	--	--	1,659,542	857,618	25,387	3,254,380
Executive Officer (4)	2010	506,667	--	--	--	681,173	445,997	25,935	1,659,772
Daniel A. Doyle	2012	$ 450,000	$ 22,534	$ --	$ --	$ 306,517	$ 147,857	$ 38,287	$ 965,195
Senior Vice President	2011	23,864	--	--	--	--	6,685	160,746	191,295
and Chief Financial Officer (5)									
Susan McLain	2012	$ 283,922	$ --	$ --	$ --	$ 299,691	$ 379,734	$ 36,391	$ 999,738
Senior Vice President,	2011	292,086	--	--	--	607,360	289,698	32,303	1,221,447
Delivery Operations (6)									
Paul M. Wiegand	2012	$ 285,000	$ 7,233	$ --	$ --	$ 286,790	$ 407,780	$ 40,000	$ 1,026,803
Senior Vice President,	2011	267,963	--	--	--	500,994	306,711	34,220	1,109,888
Energy Operations (7)									
Marla D. Mellies	2012	$ 271,349	$ 6,836	$ --	$ --	$ 220,679	$ 260,092	$ 28,680	$ 787,636
Senior Vice President,	2011	260,554	--	--	--	475,417	167,110	24,588	927,669
Chief Administrative Officer (8)									

1 *For 2012, reflects annual cash incentive compensation paid under the 2012 Goals and Incentive Plan, cash incentive compensation paid under the LTI Plan for the 2010-2012 performance cycle. Cash incentive amounts were paid in early 2013 or deferred at the executive's election. The 2012 Goals and Incentive Plan and the LTI Plan are described in further detail under "Compensation Discussion and Analysis," including the individual amounts paid to each Named Executive Officer in early 2013.*

2 *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 include 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 "2012 Pension Benefits." The change in pension value amounts for 2012 are: Ms. Harris, $1,722,264; Mr. Doyle, $147,857; Ms. McLain, $367,706; Mr. Wiegand, $404,467; and Ms. Mellies, $259,656. Also included in this column are the portions of Deferred Compensation Plan earnings that are considered above market. These amounts for 2012 are: Ms. Harris, $3,116; Mr. Doyle, $0; Ms. McLain, $12,028; Mr. Wiegand, $3,313; and Ms. Mellies, $436. See the "2012 Nonqualified Deferred Compensation" table for all Deferred Compensation Plan earnings.*

3 *All Other Compensation for 2012 is shown in detail in the table below.*

4 *Ms. Harris was promoted to President and CEO from President on March 1, 2011.*

5 *Mr. Doyle joined PSE and Puget Energy as Senior Vice President and Chief Financial Officer on November 28, 2011.*

6 *Ms. McLain has worked at PSE since April 1988.*

7 *Mr. Wiegand has worked at PSE since June 1977.*

8 *Ms. Mellies has worked at PSE since October 2005.*

Detail of All Other Compensation

Name	Perquisites and Other Personal Benefits [1]	Registrant Contributions to Defined Contribution and deferred compensation Plans [2]	Other [3]
Kimberly J. Harris	$ 2,940	$ 17,450	$ 4,584
Daniel A. Doyle	7,500	26,489	4,298
Susan McLain	—	30,135	6,256
Paul M. Wiegand	2,892	28,385	8,723
Marla D. Mellies	875	25,640	2,165

1 *After an initial reimbursement up to $7,500, annual reimbursement for financial planning, tax planning, and/or legal planning, up to a maximum of $5,000 for Ms. Harris and $2,500 for the other Named Executive Officers. Club use is primarily for business purposes, but Company club expense is included when 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 2012 to PSE's Investment Plan (a tax qualified 401(k) plan) and the Deferred Compensation Plan. Company 401 (k) contributions are as follows: Ms. Harris, $17,450; Mr. Doyle, $15,239; Ms. McLain, $15,011; Mr. Wiegand, $15,385; and Ms. Mellies, $17,450. Company contributions to the Deferred Compensation Plan are as follows: Ms. Harris, $0; Mr. Doyle, $11,250; Ms. McLain, $15,124; Mr. Wiegand, $13,000; and Ms. Mellies, $8,190.*

3 *Reflects the value of imputed income for life insurance and Company paid premiums on supplemental disability insurance.*

2012 Grants of Plan-Based Awards

The following table presents information regarding 2012 grants of non-equity annual incentive awards and LTI Plan awards, including, as applicable, the range of potential payouts for the awards.

		Estimated Future Payouts under Non-Equity Incentive Plan Awards			
Name	Grant Date	Number Of Units Granted	Threshold	Target	Maximum
Kimberly J. Harris					
Annual Incentive [1]	1/1/2012		$ 243,950	$ 697,000	$ 1,394,000
LTI Plan 2012-2014 [2]	3/2/2012	38,690	332,038	1,855,572	4,240,424
Daniel A. Doyle					
Annual Incentive [1]	1/1/2012		$ 70,875	$ 202,500	$ 405,000
LTI Plan 2012-2014 [2]	3/2/2012	11,865	101,825	569,045	1,300,404
Susan McLain					
Annual Incentive [1]	1/1/2012		$ 47,707	$ 136,305	$ 272,610
LTI Plan 2012-2014 [2]	3/2/2012	7,987	65,369	383,057	875,375
Paul M. Wiegand					
Annual Incentive [1]	1/1/2012		$ 45,502	$ 130,005	$ 260,010
LTI Plan 2012-2014 [2]	3/2/2012	7,617	65,369	365,311	834,823
Marla D. Mellies					
Annual Incentive [1]	1/1/2012		$ 42,998	$ 122,850	$ 245,700
LTI Plan 2012-2014 [2]	3/2/2012	7,198	61,773	345,216	788,901

1 *As described in the "Compensation Discussion and Analysis," the 2012 Goals and Incentive Plan had dual funding triggers in 2012 of $969.3 million EBITDA and SQI performance of 6/10. Payment would be $0 if either trigger is not met. The threshold estimate assumes $969.3 million EBITDA and SQI/Safety measure performance at 6/10. The target estimate assumes $1,077.0 million EBITDA and SQI/Safety measure performance at 10/10. The maximum estimate assumes $1454.0 million EBITDA or higher and SQI/Safety measure performance at 10/10.*

2 *As described in the "Compensation Discussion and Analysis," LTI Plan grants were allocated between a Total Return component and an ROE component. Payments are calculated based on Total Return at Puget Holdings, the average three-year performance of ROE and the unit value at the end of the performance cycle.*

2012 Pension Benefits

The Company and its affiliates maintain two pension plans: the Retirement Plan and the SERP. The following table provides information for each of the Named Executive Officers regarding the actuarial present value of the executive'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. Each of the Named Executive Officers participates in both plans.

Name	Plan Name	Number of Years Credited Service	Present Value of Accumulated Benefit [1,2]	Payments During Last Fiscal Year
Kimberly J. Harris	Retirement Plan	13.7	$ 274,152	$ —
	SERP	13.7	3,563,286	—
Daniel A. Doyle	Retirement Plan	1.1	23,511	—
	SERP	1.1	131,031	—
Susan McLain	Retirement Plan	24.7	444,864	—
	SERP	24.7	1,880,606	—
Paul M. Wiegand	Retirement Plan	35.5	616,575	—
	SERP	35.5	1,781,571	—
Marla D. Mellies	Retirement Plan	7.2	151,793	—
	SERP	7.2	653,631	—

1 *The amounts reported in this column for each executive 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, 2012 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 2013 and are assumed to be 4.0% through 2017, and 5.0% annually thereafter. The discount assumption is 4.15%, and the post-retirement mortality assumption is based on the 2013 417(e) unisex mortality table. Annuity benefits are converted to lump sum amounts at retirement based on assumed future 417(e) segment rates of 1.75%, 4.62% and 5.72% (the 24 month average of the underlying rates as of September 2012). These assumptions are consistent with the ones used for the Retirement Plan and the SERP for financial reporting purposes for 2012. 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, 2011 for the benefits earned as of that date using the assumptions used for financial reporting purposes for 2011. These assumptions included assumed cash balance interest credits of 4.0% for 2012 and 5.0% for all future years, a discount assumption of 4.75% and post-retirement mortality assumption based on the 2012 417(e) unisex mortality table. Annuity benefits were converted to lump sum amounts at retirement based on assumed future 417(e) segment rates of 2.06%, 5.25% and 6.32% (the 24 month average of the underlying rates as of September 2011). Other assumptions used to determine the value as of December 31, 2011 were the same as those used for December 31, 2012.*

2 *As described in footnote 1 above, the amounts reported for the SERP in this column are actuarial present values, calculated using the actuarial assumptions 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, 2012. Each SERP-eligible Named Executive Officer (except Dan Doyle) was vested in his or her SERP benefits as of December 31, 2012.*

Name	Lump Sum
Kimberly J. Harris	$ 6,127,843
Daniel A. Doyle	178,357
Susan McLain	2,367,921
Paul M. Wiegand	1,925,973
Marla D. Mellies	952,096

Retirement Plan

Under the Retirement Plan, the Company'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 LTI Plan and signing, retention and similar bonuses), up to the limit imposed by the Internal Revenue Code. For 2009 through 2011, the Internal Revenue Code compensation limit was $245,000. For 2012, the limit was $250,000. 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 2012 and 2013 the annual interest crediting rate was 4%.

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, 2012, all the Named Executive Officers, except Mr. Doyle, 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 mortality 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. All the Named Executive Officers participate in the SERP. As described in the "Compensation Discussion and Analysis," the Company modified certain features of the SERP, effective January 1, 2013, to ensure alignment with competitive practices and with the retention goals of the plan. The plan changes do not increase the expected cost of the SERP program, and in certain instances would decrease program costs. The plan changes include an additional vesting requirement for new participants to attain age 55 prior to vesting and a modified calculation of highest average earnings for all participants. The changes are reflected below in the description of SERP benefit calculations. The changes apply to existing and prospective SERP participants unless otherwise noted. For an existing participant, the change requiring consecutive years in the highest average earnings definition could result in a lower SERP benefit amount if high earnings years are not consecutive, compared to the benefit amount calculated under plan terms prior to January 1, 2013. On an ongoing basis, as new participants join the program, the plan changes will lead to reduced aggregate costs attributable to SERP.

A participating Named Executive Officer's SERP benefit generally vests upon the executive's completion of five years of participation in the SERP and attainment of age 55 while employed by the Company or any of its affiliates. All the participating Named Executive Officers, except Mr. Doyle, are vested in their SERP benefits. SERP participants as of December 31, 2012, who had not yet attained age 55 at that date, including Ms. Harris and Ms. Mellies, have been exempted from the age 55 vesting requirement. The Board added a special vesting requirement for Ms. Harris to continue Company service through December 31, 2016 in order to vest additional SERP benefit value after December 31, 2012.

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 consecutive calendar years of earnings. The three consecutive calendar years must be among the last ten calendar years completed by the executive prior to his or her termination. Prior to December 31, 2012, a participant's highest average earnings was not required to be calculated based on a three consecutive year basis. Executives participating in the SERP as of December 31, 2012 will have their highest average earnings on that date preserved as a minimum value for highest average earnings in the future. "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 within the Deferred Compensation Plan (including the annual cash balance restoration account). These accounts are described in more detail in the "2012 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. 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. Ms. McLain and Mr. Wiegand are the only Named Executive Officers eligible for early retirement benefit payments under the SERP as of December 31, 2012.

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, with any applicable reductions for early commencement if the executive dies before age 62. 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.

2012 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 2012 and year-end account balances under the Deferred Compensation Plan.

Name	Executive Contributions in 2012 [1]	Registrant Contributions in 2012 [2]	Aggregate Earnings in 2012 [3]	Aggregate Withdrawals/ Distributions	Aggregate Balance at December 31, 2012 [4]
Kimberly J. Harris	$ —	$ —	$ 10,858	$ —	$ 264,300
Daniel A. Doyle	10,000	11,250	67	—	21,317
Susan McLain	47,598	15,124	42,533	—	1,083,463
Paul M. Wiegand	17,581	13,000	19,787	—	510,234
Marla D. Mellies	7,953	8,190	1,521	—	53,138

1 *The amount in this column reflects elective deferrals by the executive of salary, annual incentive compensation or LTI Plan awards paid in 2012. Deferred salary amounts are: Ms. Harris, $0; Mr. Doyle, $10,000; Ms. McLain, $35,289; Mr. Wiegand, $17,581; and Ms. Mellies, $7,953. Deferred incentive compensation amounts are: Ms. Harris, $0; Mr. Doyle, $0; Ms. McLain, $12,309; Mr. Wiegand, $0; and Ms. Mellies, $0. The amounts are also included in the applicable column of the Summary Compensation Table for 2012.*

2 *The amount reported in this column reflects contributions by PSE consisting of the annual investment plan restoration amount and annual cash balance restoration amount described below. These amounts are also included in the total amounts shown in the All Other Compensation column of the Summary Compensation Table for 2012.*

3 *The amount in this column for each executive reflects the change in value of investment tracking funds. Above market earnings on these amounts are included in the Change in Pension Value and Nonqualified Deferred Compensation Earnings column of the Summary Compensation Table for 2012.*

4 *Of the amounts in this column, the following amounts have also been reported in the Summary Compensation Table for 2012, 2011, and 2010.*

Name	Reported for 2012	Reported for 2011	Reported for 2010
Kimberly J. Harris	$ 3,116	$ 2,210	$ 1,979
Daniel A. Doyle	21,250	—	—
Susan McLain	74,749	61,837	—
Paul M. Wiegand	33,894	22,539	—
Marla D. Mellies	16,579	8,079	—

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 LTI Plan payments. In addition, each year, executives are eligible to receive Company contributions under the Deferred Compensation Plan 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.

The Named Executive Officers choose how to credit deferred amounts among three investment tracking funds. The tracking funds mirror performance in major asset classes of bonds, stocks, and a money market index. For deferrals prior to 2012, an interest crediting fund was available. The tracking funds differ from the investment funds offered in the 401(k) plan. The 2012 calendar year returns of these tracking funds were:

Vanguard Total Bond Market Index	4.18%
Vanguard 500 Index	15.82%
Vanguard Money Market Index	0.04%
Interest Crediting Fund (pre-2012 deferrals)	4.28%

The Named Executive Officers may change how deferrals are allocated to the tracking funds at any time. Changes generally become effective as of the first trading day of the following calendar quarter.

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 amounts 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 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). Ms. McLain and Mr. Wiegand are the only Named Executive Officers currently retirement eligible under the Deferred Compensation Plan.

Potential Payments Upon Termination or Change in Control

The Estimated Potential Incremental Payments Upon Termination or Change in Control table below 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 by the executive for good reason 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.

Certain Company benefit plans provide incremental benefits or payments in the event of certain terminations of employment. In addition, each Named Executive Officer, other than Mr. Doyle, entered into an Executive Employment Agreement with the Company in March 2009, which provides for benefits or payments upon certain terminations of employment from the Company following the 2009 merger or a subsequent change in control. The only benefit payable to the Named Executive Officers solely upon a change in control is accelerated vesting of LTI Plan awards, described below.

Disability and Life Insurance Plans

If a Named Executive Officer's employment terminates due to disability or death, the executive or his or her estate 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 Named Executive Officer is also eligible to receive supplemental disability and life insurance. The supplemental monthly disability coverage is 65% of monthly base salary and target annual incentive pay, reduced by (i) amounts receivable under the PSE disability plan generally available to salaried employees and (ii) certain other income benefits. The supplemental 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 life insurance policy.

LTI Plan Awards

If a Named Executive Officer's employment terminates due to disability or death, the executive or his or her estate will be paid a pro-rata portion of LTI Plan awards that were granted in a prior year. In the case of retirement at normal retirement age or approved early retirement, pro-rata LTI Plan awards will be paid in the first quarter following the year of retirement, based on performance through the prior year. In the event of a change in control, outstanding LTI Plan awards will be paid at the higher of (i) target performance or (ii) actual performance achieved during the performance cycle ending with the fiscal quarter that precedes the change of control.

Employment Agreements with Named Executive Officers

In March 2009, PSE entered into Executive Employment Agreements (Employment Agreements) with each of the Named Executive Officers except Mr. Doyle (collectively, the Covered Executives), the terms of which are the same for all the Covered Executives and which amended and restated then existing Amended and Restated Change of Control Agreements between the Company and each of the Covered Executives. The Employment Agreements provide for an employment period of two years after the completion of the February 2009 merger (Employment Period) and generally provide benefits similar to those provided under the previous Change of Control Agreements. In the event of a termination of employment within two years of a change in control that occurs after the Employment Period has ended (a Covered Termination), a Covered Executive is eligible to receive the payments described below. A change in control generally means a person (or group of persons) (with certain exceptions set forth in the Employment Agreements) acquires (i) beneficial ownership of more than 55% of the total combined voting power of the Company's securities outstanding immediately after such acquisition (other than through a registered public offering) or (ii) all or substantially all of the Company's assets.

Payments upon Involuntary Termination without Cause or for Good Reason

If a Covered Executive's employment is terminated without cause by the Company or is terminated by the Covered Executive for good reason within two years of a change in control that follows the Employment Period, the Covered Executive is eligible to receive the following compensation and benefits:

- Three times the sum of annual base salary and annual incentive bonus for the year in which termination occurs;
- Pro-rated annual incentive bonus for the year in which termination occurs (Annual Bonus). Since this amount was earned for 2012, no amount is shown in the table below;
- Supplemental retirement benefit equal to the difference between (x) the actuarial equivalent of the amount the Covered Executive 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 the Covered Executive actually receives or is entitled to receive under the Retirement Plan and SERP; and
- Continued group medical, dental, disability and life insurance benefits to the Covered Executive and his or her family. Benefits will be paid by the Company while the Covered Executive is eligible for COBRA and thereafter by reimbursement of payments made by the Covered Executive for such coverage (including related tax amounts), except that if the Covered 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 under the Employment Agreement will become secondary to those provided by the other employer (the foregoing benefit is referred to as Health and Welfare Benefit Continuation).

Under the Employment Agreements, "cause" and "good reason" have the following meanings:

Cause generally means (i) the willful and continued failure by the Covered Executive to substantially perform the Covered Executive's duties with the Company (other than any such failure resulting from incapacity due to physical or mental illness) for a period of 30 days after written notice of demand for substantial performance has been delivered to the Covered Executive or (ii) the Covered Executive's willfully engaging in gross misconduct materially and demonstrably injurious to the Company, as determined by the Board after notice to the executive and opportunity for a hearing. No act or failure to act on the Covered Executive's part is considered "willful" unless the Covered Executive has acted or failed to act with an absence of good faith and without a reasonable belief that the Covered Executive's action or failure to act was in the best interests of the Company.

Good Reason generally means (i) the assignment of the Covered Executive to a non-officer position with the Company, which the parties agree would constitute a material reduction in the Covered Executive's authority, duties or responsibilities; (ii) a material diminution in the Covered Executive's total compensation opportunities under the Employment Agreement; (iii) the Company's requiring the Covered Executive to be based at any location that represents a material change from the Covered Executive's location in the Seattle/Bellevue metropolitan area, unless the Covered Executive consents to the relocation; or (iv) a material breach of the Employment Agreement by the Company, provided that, in any of the foregoing, the Company has not remedied the alleged violation(s) within 60 days of notice from the Covered Executive.

Payments upon Retirement, Disability or Death

In the event of a Covered Termination due to voluntary retirement after having attained age 55 with a minimum of five years of service to the Company, a pro-rated Annual Bonus is payable to the Covered Executive. The bonus is payable at the time the Covered Executive otherwise would have received the payment had employment continued, based on the Company's actual achievement of performance goals.

In the event of a Covered Termination due to disability or death, the Covered Executive is eligible to receive the following compensation and benefits:

- Pro-rated Annual Bonus; and
- Health and Welfare Benefit Continuation.

In addition, upon termination for any of the foregoing reasons during the Employment Period, other than by reason of retirement, the Covered Executive is eligible to receive the perquisite of financial planning.

Except as otherwise described above, payments of salary and bonus will be paid after the date of termination, subject to the Covered Executive's timely execution of a general waiver and release of claims.

The Employment Agreements also contain noncompetition and anti-solicitation provisions that restrict the Covered Executive during the Employment Period and for twelve months thereafter from, respectively, engaging in activities related to selling or distributing electric power or natural gas in Washington or soliciting others to leave the Company or causing them to be hired from the Company by another entity. The Employment Agreements contain a non-disparagement clause and a confidentiality clause pursuant to which the Covered Executives must keep confidential all secret or confidential information, knowledge or data relating to the Company and its affiliates obtained during their employment. The Covered 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.

If any payments paid or payable in connection with a change in control while the Company's stock is not traded on an established securities market or otherwise immediately before such change in control, then the Covered Executive will agree to execute a waiver of any "excess parachute payments" (within the meaning of Section 280G of the Internal Revenue Code), provided that the Company agrees to seek, but is not required to obtain, shareholder approval of the amount payable in connection with termination of employment, in which case the waived amounts will be restored to the Covered Executive.

Estimated Potential Incremental Payments Upon Termination or Change in Control

The amounts shown in the table below assume that the termination of employment of a Named Executive Officer or a change in control was effective as of December 31, 2012. The amounts below are estimates of the incremental amounts that would be paid out to the Named Executive Officer upon a termination of employment or a change in control. Actual amounts payable can only be determined at the time of a termination of employment or a 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
Kimberly J. Harris						
Cash Severance (salary and/or annual incentive)	n/a	$ —	$ 4,551,000	$ —	$ —	$ —
Long Term Incentive Plan	—	3,613,517	3,613,517	—	998,395	998,395
SERP (additional years of credited service) [1]	—	—	961,191	—	—	—
Benefits (continuation) [2]	n/a	—	29,908	—	29,908	29,908
Supplemental Life Insurance	n/a	—	—	—	—	1,994,000
Total Estimated Incremental Value	n/a	$ 3,613,517	$ 9,155,616	$ —	$ 1,028,303	$ 3,022,303
Daniel A. Doyle						
Long Term Incentive Plan	—	$ —	$ 901,070	—	$ 272,453	$ 272,453
SERP (additional years of credited service) [1]	—	—	—	—	—	—
Benefits (continuation) [2]	n/a	—	—	—	—	—
Supplemental Life Insurance	n/a	—	—	—	—	$ 855,000
Total Estimated Incremental Value	n/a	$ —	$ 901,070	$ —	$ 272,453	$ 1,127,453
Susan McLain						
Cash Severance (salary and/or annual incentive)	n/a	$ —	$ 1,317,615	$ —	$ —	$ —
Long Term Incentive Plan	—	901,386	901,386	315,481	315,481	315,481
SERP (additional years of credited service) [1]	n/a	—	—	—	—	—
Benefits (continuation) [2]	n/a	—	23,604	—	23,604	23,604
Supplemental Life Insurance	n/a	—	—	—	—	575,510
Total Estimated Incremental Value	n/a	$ 901,386	$ 2,242,605	$ 315,481	$ 339,085	$ 914,595
Paul M. Wiegand						
Cash Severance (salary and/or annual incentive)	n/a	$ —	$ 1,256,715	$ —	$ —	$ —
Long Term Incentive Plan	—	836,551	836,551	291,075	291,075	291,075
SERP (additional years of credited service) [1]	n/a	—	—	—	—	—
Benefits (continuation) [2]	n/a	—	40,526	—	40,526	40,526
Supplemental Life Insurance	n/a	—	—	—	—	564,810
Total Estimated Incremental Value	n/a	$ 836,551	$ 2,133,792	$ 291,075	$ 331,601	$ 896,411
Marla D. Mellies						
Cash Severance (salary and/or annual incentive)	n/a	$ —	$ 1,187,550	$ —	$ —	$ —
Long Term Incentive Plan	—	699,894	699,894	—	228,084	228,084
SERP (additional years of credited service) [1]	n/a	—	329,832	—	—	—
Benefits (continuation) [2]	n/a	—	38,057	—	38,057	38,057
Supplemental Life Insurance	n/a	—	—	—	—	483,700
Total Estimated Incremental Value	n/a	$ 699,894	$ 2,255,333	$ —	$ 266,141	$ 749,841

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, 2012. These values are based on interest rate and mortality rate assumptions consistent with those used in the Company's financial statements.*

2 *Benefits (continuation) reflects the value of continued medical, dental, disability and life insurance benefits as well as financial planning benefit in the amount of $5,000 for Ms. Harris and $2,500 for all the other Named Executive Officers.*

Director Compensation for Fiscal Year 2012

The following table sets forth information regarding compensation paid by the Company to the directors named in the table who received compensation from the Company in 2012 for service as directors. We refer to these directors as nonemployee directors. Directors who are employed by the Company or by the Company's investor-owners are not paid separately for their service and thus are not named in the table below. The directors who are employed by the Company's investor-owners are: Andrew Chapman, Daniel Fetter, Benjamin Hawkins, Alan James, Alan Kadic (who resigned in August 2012), Christopher Leslie, David MacMillan, John McMahon, and Mark Wiseman (who resigned in November, 2012). Kimberly Harris is employed by the Company and also serves as a director.

As described in further detail below, the Company's nonemployee director compensation program in 2012 consisted of quarterly retainer cash fees of $20,000. Additional quarterly retainer amounts associated with serving as Chair of the Board, chairing Board committees, serving on the Audit Committee and meeting fees were also paid in cash.

Name	Fees Earned	Nonqualified Deferred Compensation Earnings [1]	Total
William Ayer	$ 141,600	$ 6,474	$ 148,074
Melanie Dressel[2]	68,000	—	68,000
David MacMillan[3]	—	—	—
Herbert Simon	109,200	3,781	112,981
Christopher Trumpy	108,800	—	108,800
Mary O. McWilliams	98,400	—	98,400

1 *Represents earnings accrued on deferred compensation considered to be above market.*

2 *Ms. Dressel was appointed as a nonemployee director on December 19, 2011.*

3 *Mr. MacMillan was appointed as a nonemployee director on November 6, 2012.*

Nonemployee Director Compensation Program. The 2012 nonemployee director compensation program is based on the principles that the level of nonemployee director compensation should be based on Board and committee responsibilities and should be competitive with comparable companies.

The 2012 compensation program for nonemployee directors was as follows:

- A base cash quarterly retainer fee of $20,000
- $1,600 for attendance at each in-person Board and committee meeting
- $800 for each telephonic meeting lasting 60 minutes or less, and $1,600 for each telephonic meeting lasting more than 60 minutes

In 2012, nonemployee directors were paid the following additional cash quarterly retainer fees:

- Independent Board Chairman, $10,000
- Chair of the Governance and Public Affairs Committees, $1,500
- Chair of the Audit Committee, $2,500
- Each member of the Audit Committee other than the chair, $1,000

Nonemployee directors were reimbursed for actual travel and out-of-pocket expenses incurred in connection with their services.

Nonemployee directors are eligible to participate in the Company's matching gift program on the same terms as all Puget Energy employees. Under this program, the Company matches up to a total of $300 a year in contributions by a director to non-profit organizations that have IRS 501(c)(3) tax exempt status and are located in and served the people of PSE's service territory in Washington State.

Deferral of Compensation. Nonemployee directors may choose to elect to defer all or a part of their cash fees under the Company's Deferred Compensation Plan for Nonemployee Directors. Nonemployee directors may allocate these deferrals into one or more "measurement funds," which include an interest crediting fund, an equity index fund and a bond index fund. Nonemployee directors are permitted to make changes in measurement fund allocations quarterly. None of the independent board members deferred any director fees during 2012.

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 December 31, 2012 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 and its affiliates beneficially own 100.0% of the outstanding common stock of Puget Energy. Puget Energy holds 100.0% 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 December 31, 2012.

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 Holdings Inc. (Puget Intermediate), Puget Holdings (Puget Holdings and together with Puget Intermediate, the Parent Entities), Macquarie Infrastructure Partners I (formerly MIP Padua Holdings GP) (MIP), Macquarie Infrastructure Partners II (formerly MIP Washington Holdings, L.P.) (MIP II), FSS Infrastructure Trust (formerly Macquarie-FSS Infrastructure Trust) (FIT), Padua MG Holdings LLC (PMGH) Canada Pension Plan Investment Board (USRE II) Inc. (CPPIB), 6860141 Canada Inc. as trustee for British Columbia Investment Management Corporation (bcIMC), PIP2PX (Pad) Ltd. (PIP2PX) and PIP2GV (Pad) Ltd. (PIP2GV and together with MIP, MIP II, FIT, PMGH, CPPIB, bcIMC and PIP2PX, the Investors). Puget Equico is a wholly-owned subsidiary of Puget Intermediate, Puget Intermediate is a wholly-owned subsidiary of Puget Holdings and the Investors are the direct or indirect owners of Puget Holdings. The Parent Entities and the Investors are the direct or indirect owners of Puget Equico. Although the Parent Entities and the Investors do not own any shares of Puget Energy directly, Puget Equico, the Parent Entities and the 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 100.0% 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 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 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, 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 FIT is Level 21, 83 Clarence Street, 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 CPPIB is One Queen Street East, Suite 2600, P.O. Box 101, Toronto, Ontario, Canada M5C 2W5.*
   - *The address of the principal office of bcIMC is Sawmill Point, Suite 301-2940 Jutland Road, Victoria, British Columbia, Canada V8T 5K6.*
   - *The address of the principal office of PIP2PX and PIP2GV is 1100, 10830 Jasper Avenue, Edmonton, Alberta, Canada T5J 2B3.*
2. *Pursuant to that certain Pledge Agreement dated as of May 10, 2010, as amended on February 10, 2012, made by Puget Equico to JPMorgan Chase Bank, N.A., as administrative agent, the outstanding stock of Puget Energy held by Puget Equico was pledged by Puget Equico to secure the obligations of Puget Energy under (a) the Credit Agreement dated as of February 10, 2012 among Puget Energy., JPMorgan Chase Bank, N.A., as administrative agent, the other agents party thereto, and the lenders party thereto and (b) the senior secured notes issued on December 6, 2010, June 3, 2011 and June 15, 2012.*
3. *Pursuant to that certain Borrower's Security Agreement dated as of May 10, 2010, as amended on February 10, 2012, the outstanding stock of PSE held by Puget Energy was pledged by Puget Energy to secure its obligations under (a) the Credit Agreement dated as of February 10, 2012 among Puget Energy as Borrower, JPMorgan Chase Bank, N.A., as administrative agent, the other agents party thereto, and the lenders party thereto and (b) the senior secured notes issued on December 6, 2010, June 3, 2011 and June 15, 2012.*

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, except the LTI Plan. Following the merger, only non-equity awards that can be settled solely in cash are made under the LTI Plan.

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.

Kimberly Harris, the President and Chief Executive Officer, and a director of Puget Energy and PSE, is married to Kyle Branum, a principal at the law firm Riddell Williams P.S., one of PSE's primary law firms for nearly 50 years. In 2012, Riddell Williams was paid $1.59 million for legal services provided to PSE and Mr. Branum is among the lawyers at Riddell Williams who provided such legal services. This work was performed under the supervision of PSE's general counsel and the compensation arrangements were comparable to other regional law firms providing legal services to PSE.

Puget Energy is party to interest rate swap agreements, negotiated under the International Swaps and Derivatives Association, Inc. ("ISDA agreements"), with various parties, including Macquarie Bank Limited. Affiliates of Macquarie Bank Limited indirectly own an equity interest in PSE. The ISDA agreements were the product of arms' length negotiations between Puget Energy and the various counterparties, including Macquarie Bank Limited, and contain terms and conditions similar to those of other master swap agreements with unrelated third parties.

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. Based on this review, the Boards have determined that of the members constituting the Boards, William Ayer (member of the Boards of both Puget Energy and PSE), Mary McWilliams (member of the Boards of both Puget Energy and PSE), Melanie Dressel (member of the Boards of both Puget Energy and PSE), and Herbert Simon (member of the Board of PSE) are independent under the 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. The Company's definition of "Independent Director" is available in the Corporate Governance Guidelines at www.pugetenergy.com.

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 revenue, 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 their respective subsidiaries), including some that are not required to be disclosed in this report as related-person transactions. Messrs. Ayer and Simon, Ms. McWilliams and Ms. Dressel 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 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 Mr. Ayer serve as a director, 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 revenue. 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 the Company or the other entity, the Boards have 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. 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 years ended December 31 were as follows:

	2012		2011	
(Dollars in Thousands)	Puget Energy	PSE	Puget Energy	PSE
Audit fees [1]	$ 1,671	$ 1,558	$ 1,632	$ 1,519
Audit related fees [2]	479	359	387	325
Tax fees [3]	17	17	—	27
Total	$ 2,167	$ 1,934	$ 2,019	$ 1,871

1 *For professional services rendered for the audit of Puget Energy's and PSE's annual financial statements and reviews of financial statements included in the Company's Forms 10-Q. The 2012 fees are estimated and include an aggregate amount of $1.0 million billed to Puget Energy and $0.9 million to PSE through December 2012.*

2 *Consists of employee benefit plan audits, work performed in connection with registration statements and other regulatory audits.*

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 Committee. In addition, on an annual basis, the Audit Committee grants 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 Committee regarding the specific services to be provided. Under the policies, the Audit Committee 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 the Audit Committee at its next scheduled meeting. The Audit Committee does not delegate responsibilities to pre-approve services performed by the independent registered public accounting firm to management.

For 2012 and 2011, 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.
   2) Financial Statement Schedules. Financial Statement Schedules of the Company, as required for the years ended December 31, 2012, 2011 and 2010, consist of the following:

      I. Condensed Financial Information of Puget Energy
      II. Valuation of Qualifying Accounts and Reserves

   3) Exhibits

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/ Kimberly J. Harris	/s/ Kimberly J. Harris
Kimberly J. Harris	Kimberly J. Harris
President and Chief Executive Officer	President and Chief Executive Officer
Date: March 4, 2013	Date: March 4, 2013

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

Signature	Title	Date
	(Puget Energy and PSE unless otherwise noted)	
/s/ Kimberly J. Harris (Kimberly J. Harris)	President and Chief Executive Officer	March 4, 2013
/s/ Daniel A. Doyle (Daniel A. Doyle)	Senior Vice President and Chief Financial Officer	
/s/ Michael J. Stranik (Michael J. Stranik)	Controller and Principal Accounting Officer	
/s/ William S. Ayer (William S. Ayer)	Chairman and Director	
/s/ Andrew Chapman (Andrew Chapman)	Director	
/s/ Melanie Dressel (Melanie Dressel)	Director	
/s/ Daniel Fetter (Daniel Fetter)	Director	
/s/ Benjamin Hawkins (Benjamin Hawkins)	Director	
/s/ Alan W. James (Alan W. James)	Director	
/s/ Christopher J. Leslie (Christopher J. Leslie)	Director	
/s/ David MacMillan (David MacMillan)	Director	

/s/ John McMahon	Director
(John McMahon)	
/s/ Mary O. McWilliams	Director
(Mary O. McWilliams)	
/s/ Christopher Trumpy	Director
(Christopher Trumpy)	
/s/ Herbert B. Simon	Director of PSE only
(Herbert B. Simon)	

EXHIBIT INDEX

Certain of the following exhibits are filed herewith. Certain other of the following exhibits have heretofore been filed with the United States Securities and Exchange Commission (SEC) 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 Sixtieth Supplemental Indentures defining the rights of the holders of Puget Sound Energy's Electric Utility First Mortgage Bond (incorporated herein by reference to Exhibits 4.3 through and including 4.23 to Puget Sound Energy's Registration Statement on Form S-3ASR, filed March 13, 2009, Registration No. 333-157960).

4.4 Sixty-first through Eighty-seventh Supplemental Indentures defining the rights of the holders of Puget Sound Energy's Electric Utility First Mortgage Bonds (incorporated herein by reference to 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); Exhibit 4.1 to Puget Sound Energy's Current Report on Form 8-K, dated September 8, 2009, Commission File No. 1-4393.

4.5 Eighty-eighth, Eighty-ninth and Ninetieth Supplemental Indentures defining the rights of the holders of Puget Sound Energy's Electric Utility First Mortgage Bonds (incorporated herein by reference to Exhibits 4.1 through 4.3 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2012, Commission File No. 1-4393).

4.6 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 Puget Sound Energy's Registration Statement on Form S-3ASR, filed March 13, 2009, Registration No. 333-157960).

4.7 First, Sixth, Seventh and Seventeenth Supplemental Indenture to the Gas Utility First Mortgage, dated as of October 1, 1959, August 1, 1966, February 1, 1967, June 1, 1977 and August 9, 1978, respectively (incorporated herein by reference to Exhibits 4.26 through and including 4.30 to Puget Sound Energy's Registration Statement on Form S-3ASR, filed March 13, 2009, Registration No. 333-157960).

4.8 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).

4.9 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).

4.10 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).

4.11 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).

4.12 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).

4.13 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).

4.14 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).

4.15 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).

4.16 Indenture and First Supplemental Indenture between Wells Fargo Bank, National Association and Puget Energy, Inc. dated as of December 6, 2010 (incorporated by reference to Exhibits 4.1 and 4.2 to Puget Energy's Current Report on Form 8-K, filed December 7, 2010, Commission File No. 1-16305).

4.17 Second Supplemental Indenture to the Indenture dated December 6, 2010 between Puget Energy, Inc. and Wells Fargo Bank, National Association defining the rights of Puget Energy's Senior Secured Notes due September 1, 2021 (incorporated herein by reference to Exhibit 4.1 to Puget Energy's Current Report on Form 8-K, filed June 6, 2011, Commission File No. 1-16305).

4.18 Third Supplemental Indenture between Wells Fargo Bank, National Association and Puget Energy, Inc. dated as of June 15, 2012 (incorporated by reference to Exhibits 4.1 to Puget Energy's Current Report on Form 8-K, filed June 18, 2012, Commission File No. 1-16305).

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 10.1 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

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 10.2 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

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 10.3 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

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 10.4 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

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 10.5 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

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 10.6 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

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 10.7 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

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 10.8 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

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 10.9 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

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 10.10 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

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 10.11 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

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 10.12 to Puget Sound Energy's Report on Form 10-Q for the quarter ended March 31, 2009, Commission File No. 1-4393).

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 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).

10.21 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).

10.22 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).

10.23 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).

10.24 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).

10.25 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).

10.26 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).

10.27 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).

10.28 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).

10.29 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).

10.30 Credit Agreement dated as of February 10, 2012 among Puget Energy, Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, the other agents party thereto, and the lenders party thereto (incorporated herein by reference to Exhibit 10.1 to Puget Energy's and Puget Sound Energy's Report on Form 8-K dated February 16, 2012, Commission File Nos. 1-16305 and 1-4393).

10.31 Amendment No. 1 dated April 6, 2012 to Credit Agreement dated as of February 10, 2012 among Puget Energy, Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, the other agents party thereto, and the lenders party thereto (incorporated herein by reference to Exhibit 10.2 to Puget Energy's Report on Form 10-Q for the quarter ended March 31, 2012, Commission File No. 1-16305).

10.32 Credit Agreement dated as of February 4, 2013 among Puget Sound Energy, Inc., as Borrower, Wells Fargo Bank, National Association, as Administration Agent, the other agents party thereto, and the lenders party thereto. (incorporated herein by reference to Exhibit 10.1 to Puget Energy's and Puget Sound Energy's Report on Form 8-K dated February 11, 2013, Commission File Nos. 1-16305 and 1-4393).

** 10.33 Form of Executive Employment Agreement with Executive Officers (incorporated herein by reference to Exhibit 10.1 to Puget Sound Energy's Current Report on Form 8-K, dated April 3, 2009, Commission File No. 1-4393).

** 10.34 Puget Sound Energy, Inc. Amended and Restated Supplemental Executive Retirement Plan effective January 1, 2009 (incorporated herein by reference to Exhibit 10.39 to Puget Energy's and Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2008, Commission File No. 1-16305 and 1-4393).

* 10.35 Puget Sound Energy, Inc. Amended and Restated Supplemental Executive Retirement Plan effective January 1, 2013.

** 10.36 Puget Sound Energy, Inc. Amended and Restated Deferred Compensation Plan for Key Employees effective January 1, 2009 (incorporated herein by reference to Exhibit 10.40 to Puget Energy's and Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2008, Commission File No. 1-16305 and 1-4393).

** 10.37 Puget Sound Energy, Inc. Amended and Restated Deferred Compensation Plan for Nonemployee Directors effective January 1, 2009 (incorporated herein by reference to Exhibit 10.41 to Puget Energy's and Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2008, Commission File No. 1-16305 and 1-4393).

**	10.38	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).
**	10.39	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).
**	10.40	Puget Sound Energy, Inc. Supplemental Death Benefit Plan for Executive Employees, effective October 1, 2000, as amended (incorporated herein by reference to Exhibit 10.45 to Puget Energy's and Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2008, Commission File No. 1-16305 and 1-4393).
**	10.41	Puget Sound Energy, Inc. Supplemental Death Benefit Plan for Executive Employees, effective January 1, 2002, as amended (incorporated herein by reference to Exhibit 10.46 to Puget Energy's and Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2008, Commission File No. 1-16305 and 1-4393).
**	10.42	Puget Sound Energy, Inc. Supplemental Disability Plan for Executive Employees, effective October 1, 2000, as amended (incorporated herein by reference to Exhibit 10.47 to Puget Energy's and Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2008, Commission File No. 1-16305 and 1-4393).
**	10.43	Puget Sound Energy, Inc. Supplemental Death Benefit Plan for Executive Employees, effective November 1, 2007, as amended (incorporated herein by reference to Exhibit 10.48 to Puget Energy's and Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2008, Commission File No. 1-16305 and 1-4393).
**	10.44	Puget Energy, Inc. Amended and Restated 2005 Long-Term Incentive Plan, effective March 4, 2011 (incorporated herein by reference to Exhibit 10.52 to Puget Energy's and Puget Sound Energy's Report on Form 10-K for the fiscal year ended December 31, 2010, Commission File No. 1-16305 and 1-4393).
*	12.1	Statement setting forth computation of ratios of earnings to fixed charges of Puget Energy, Inc. (2008 through 2012).
*	12.2	Statement setting forth computation of ratios of earnings to fixed charges of Puget Sound Energy, Inc. (2008 through 2012).
*	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 – Kimberly J. Harris.
*	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 – Daniel A. Doyle.
*	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 – Kimberly J. Harris.
*	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 – Daniel A. Doyle.
*	32.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 – Kimberly J. Harris.
*	32.2	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 – Daniel A. Doyle.
***	101	Financial statements from the annual report on Form 10-K of Puget Energy, Inc. and Puget Sound Energy, Inc. for the fiscal year ended December 31, 2012, filed on March 4, 2013, formatted in XBRL: (i) the Consolidated Statement of Income (Unaudited), (ii) the Consolidated Statements of Comprehensive Income (Unaudited), (iii) the Consolidated Balance Sheets (Unaudited), (iii) the Consolidated Statements of Cash Flows (Unaudited), and (iv) the Notes to Consolidated Financial Statements tagged as blocks of text (submitted electronically herewith).

* *Filed herewith.*

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

*** *In accordance with Rule 406T of Regulation S-T, the XBRL information in Exhibit 101 to this annual report on Form 10-K shall not be deemed to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (Exchange Act), or otherwise subject to the liability of that section, and shall not be incorporated by reference into any registration statement or other document filed under the Securities Act of 1933, as amended, or the Exchange Act, except as shall be expressly set forth by specific reference in such filing.*