NORTHWEST NATURAL GAS CO
Form 10-Q
August 03, 2011

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

Form 10-Q

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

For the quarterly period ended June 30, 2011

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 No. 1-15973

NORTHWEST NATURAL GAS COMPANY
(Exact name of registrant as specified in its charter)

Oregon (State or other jurisdiction of incorporation or organization)	93-0256722 (I.R.S. Employer Identification No.)

220 N.W. Second Avenue, Portland, Oregon 97209
(Address of principal executive offices) (Zip Code)

Registrant’s telephone number, including area code: (503) 226-4211

Indicate by check mark whether the registrant (1) has 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 registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [X] No [ ]

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes [X] No [ ]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer [X]	Accelerated filer [ ]
Non-accelerated filer [ ] (Do not check if a smaller reporting company)	Smaller reporting company [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes [ ] No [X]

At July 29, 2011, 26,674,187 shares of the registrant's Common Stock (the only class of Common Stock) were outstanding.

NORTHWEST NATURAL GAS COMPANY

For the Quarterly Period Ended June 30, 2011

PART I. FINANCIAL INFORMATION

Table of Contents

Forward-Looking Statements

This report contains “forward-looking statements” within the meaning of the U.S. Private Securities Litigation Reform Act of 1995. Forward-looking statements can be identified by words such as “anticipates,” “intends,” “plans,” “seeks,” “believes,” “estimates,” “expects” and similar references to future periods. Examples of forward-looking statements include, but are not limited to, statements regarding the following:

- plans;
- objectives;
- goals;
- strategies;
- future events or performance;
- trends;
- cyclicality;
- earnings and dividends;
- growth;
- customer rates;
- commodity costs;
- operational performance and costs;
- liquidity and financial positions;
- project development and expansion;
- competition;
- storage levels, and values;
- procurement, development and production levels of gas supplies and reserves;
- liquefied natural gas;
- estimated expenditures and investments;
- costs of compliance;
- credit exposures;
- potential efficiencies;
- impacts of laws, rules and regulations;
- tax liabilities or refunds;
- outcomes and effects of litigation, regulatory actions, and other administrative matters;
- projected status and obligations under retirement plans;
- adequacy of, and shift in mix of, gas supplies;
- approval and adequacy of regulatory deferrals; and
- costs and recovery related to environmental, regulatory, litigation and insurance.

Forward-looking statements are based on our current expectations and assumptions regarding our business, the economy and other future conditions. Because forward-looking statements relate to the future, they are subject to inherent uncertainties, risks, and changes in circumstances that are difficult to predict. Our actual results may differ materially from those contemplated by the forward-looking statements. We therefore caution you against relying on any of these forward-looking statements. They are neither statements of historical fact nor guarantees or assurances of future performance. Important factors that could cause actual results to differ materially from those in the forward-looking statements are discussed in our 2010 Annual Report on Form 10-K, Part I, Item 1A. “Risk Factors” and Part II, Item 7. and Item 7A., “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Quantitative and Qualitative Disclosures about Market Risk,” and in Part I, Items 2 and 3, “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Quantitative and Qualitative Disclosures About Market Risk,” and Part II, Item 1A, “Risk Factors,” herein.

Any forward-looking statement made by us in this report speaks only as of the date on which it is made. Factors or events that could cause our actual results to differ may emerge from time to time, and it is not possible for us to predict all of them. We undertake no obligation to publicly update any forward-looking statement, whether as a result of new information, future developments or otherwise, except as may be required by law.

Table of Contents

NORTHWEST NATURAL GAS COMPANY
PART I. FINANCIAL INFORMATION

Consolidated Statements of Income
(Unaudited)

Thousands, except per share amounts	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Operating revenues:				
Gross operating revenues	$161,197	$162,365	$484,285	$448,894
Less: Cost of sales	90,122	86,301	270,747	234,862
Revenue taxes	3,843	3,871	11,798	10,913
Net operating revenues	67,232	72,193	201,740	203,119
Operating expenses:				
Operations and maintenance	30,374	28,406	61,546	59,072
General taxes	6,659	7,543	14,824	10,792
Depreciation and amortization	17,546	16,026	34,855	31,927
Total operating expenses	54,579	51,975	111,225	101,791
Income from operations	12,653	20,218	90,515	101,328
Other income and expense - net	1,122	1,613	2,336	4,636
Interest expense - net	10,266	10,617	20,715	21,106
Income before income taxes	3,509	11,214	72,136	84,858
Income tax expense	1,316	4,326	29,170	34,362
Net income	$2,193	$6,888	$42,966	$50,496
Average common shares outstanding:				
Basic	26,673	26,569	26,671	26,553
Diluted	26,727	26,641	26,725	26,621
Earnings per share of common stock:				
Basic	$0.08	$0.26	$1.61	$1.90
Diluted	$0.08	$0.26	$1.61	$1.90
Dividends declared per share of common stock	$0.435	$0.415	$0.870	$0.830

See Notes to Consolidated Financial Statements.

Table of Contents

NORTHWEST NATURAL GAS COMPANY
PART I. FINANCIAL INFORMATION

Consolidated Balance Sheets
(Unaudited)

Thousands	June 30, 2011	June 30, 2010	December 31, 2010
Assets:			
Current assets:			
Cash and cash equivalents	$3,700	$7,142	$3,457
Restricted cash	925	929	924
Accounts receivable	39,104	42,781	67,969
Accrued unbilled revenue	15,031	16,419	64,803
Allowance for uncollectible accounts	(2,824)	(2,577)	(2,950)
Regulatory assets	59,766	56,804	52,714
Derivative instruments	4,433	1,495	2,245
Inventories:			
Gas	61,318	68,735	70,672
Materials and supplies	9,911	8,714	9,713
Gas reserves	749	-	-
Income taxes receivable	26,285	-	41,066
Other current assets	9,496	9,823	19,652
Total current assets	227,894	210,265	330,265
Non-current assets:			
Property, plant and equipment	2,612,147	2,482,826	2,576,402
Less: Accumulated depreciation	744,929	710,732	722,239
Total property, plant and equipment - net	1,867,218	1,772,094	1,854,163
Gas reserves	15,403	-	-
Regulatory assets	326,081	329,197	348,897
Derivative instruments	1,042	453	628
Other investments	68,576	68,393	69,094
Other non-current assets	15,780	15,159	13,569
Total non-current assets	2,294,100	2,185,296	2,286,351
Total assets	$2,521,994	$2,395,561	$2,616,616

See Notes to Consolidated Financial Statements.

Table of Contents

NORTHWEST NATURAL GAS COMPANY
PART I. FINANCIAL INFORMATION

Consolidated Balance Sheets
(Unaudited)

Thousands	June 30, 2011	June 30, 2010	December 31, 2010
Capitalization and liabilities:			
Capitalization:			
Common stock - no par value; authorized 100,000 shares; issued and outstanding 26,673, 26,576, and 26,668 at June 30, 2011 and 2010 and December 31, 2010, respectively	$344,451	$339,394	$342,978
Retained earnings	376,489	357,173	356,727
Accumulated other comprehensive income (loss)	(6,312)	(5,772)	(6,604)
Total common stock equity	714,628	690,795	693,101
Long-term debt	551,700	591,700	591,700
Total capitalization	1,266,328	1,282,495	1,284,801
Current liabilities:			
Short-term debt	185,400	106,875	257,435
Current maturities of long-term debt	40,000	45,000	10,000
Accounts payable	54,148	81,675	93,243
Taxes accrued	6,805	13,008	10,579
Interest accrued	5,127	5,397	5,182
Regulatory liabilities	25,784	29,524	17,828
Derivative instruments	25,986	34,463	38,437
Other current liabilities	37,574	31,900	35,457
Total current liabilities	380,824	347,842	468,161
Deferred credits and other non-current liabilities:			
Deferred tax liabilities	398,825	316,152	373,409
Regulatory liabilities	265,703	251,585	258,031
Pension and other postretirement benefit liabilities	130,985	120,185	144,250
Derivative instruments	9,202	16,917	17,022
Other non-current liabilities	70,127	60,385	70,942
Total deferred credits and other non-current liabilities	874,842	765,224	863,654
Commitments and contingencies (see Note 14)	-	-	-
Total capitalization and liabilities	$2,521,994	$2,395,561	$2,616,616

See Notes to Consolidated Financial Statements.

Table of Contents

NORTHWEST NATURAL GAS COMPANY
PART I. FINANCIAL INFORMATION

Consolidated Statements of Cash Flows
(Unaudited)

	Six Months Ended June 30,	
Thousands	2011	2010
Operating activities:		
Net income	$42,966	$50,496
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and amortization	34,855	31,927
Undistributed (earnings) losses from equity investments	353	(728)
Non-cash expenses related to qualified defined benefit pension plans	3,655	4,131
Contributions to qualified defined benefit pension plans	(16,445)	(10,000)
Deferred environmental expenditures	(1,770)	(4,286)
Other	(1,172)	(1,264)
Changes in assets and liabilities:		
Receivables	79,711	88,920
Inventories	9,156	3,508
Taxes accrued	11,007	(8,029)
Accounts payable	(30,052)	(39,323)
Interest accrued	(55)	(38)
Deferred gas costs	2,682	(18,336)
Deferred tax liabilities	27,516	15,979
Other - net	6,328	(8,694)
Cash provided by operating activities	168,735	104,263
Investing activities:		
Capital expenditures	(47,815)	(125,966)
Utility gas reserves	(16,152)	-
Restricted cash	(1)	34,614
Other	68	964
Cash used in investing activities	(63,900)	(90,388)
Financing activities:		
Common stock issued (purchased) - net, including common stock expense	(70)	1,613
Long-term debt retired	(10,000)	-
Change in short-term debt	(72,035)	4,875
Cash dividend payments on common stock	(23,204)	(22,035)
Other	717	382
Cash used in financing activities	(104,592)	(15,165)
Increase (decrease) in cash and cash equivalents	243	(1,290)
Cash and cash equivalents - beginning of period	3,457	8,432
Cash and cash equivalents - end of period	$3,700	$7,142
Supplemental disclosure of cash flow information:		
Interest paid	$20,770	$20,370
Income taxes paid	$1,522	$21,100

See Notes to Consolidated Financial Statements.

5

Table of Contents

NORTHWEST NATURAL GAS COMPANY
PART I. FINANCIAL INFORMATION

Notes to Consolidated Financial Statements
(Unaudited)

1. Organization and Principles of Consolidation

The accompanying consolidated financial statements represent the consolidation of Northwest Natural Gas Company (NW Natural) and all companies that we directly or indirectly control, either through majority ownership or otherwise. Our direct and indirect wholly-owned subsidiaries include Gill Ranch Storage, LLC (Gill Ranch), NW Natural Energy, LLC (NWN Energy), NW Natural Gas Storage, LLC (NWN Gas Storage), and NNG Financial Corporation (NNG Financial). Investments in corporate joint ventures and partnerships that we do not directly or indirectly control, and for which we are not the primary beneficiary, are accounted for under the equity method or the cost method, which includes NWN Energy's investment in Palomar Gas Holdings, LLC (PGH). NW Natural and its affiliated companies are collectively referred to herein as "NW Natural." The consolidated financial statements are presented after elimination of all significant intercompany balances and transactions, except for amounts required to be included under regulatory accounting standards to reflect the effect of such regulation. In this report, the term "utility" is used to describe our regulated gas distribution business, and the term "non-utility" is used to describe our gas storage business and other non-utility investments and business activities (see Note 4).

Information presented in these interim consolidated financial statements is unaudited, but includes all material adjustments that management considers necessary for a fair statement of the results for each period reported including normal recurring accruals. These consolidated financial statements should be read in conjunction with the audited consolidated financial statements and related notes included in our 2010 Annual Report on Form 10-K (2010 Form 10-K). A significant part of our business is of a seasonal nature; therefore, results of operations for interim periods are not necessarily indicative of the results for a full year.

Our significant accounting policies are described in Note 2 of the 2010 Form 10-K. There were no material changes to those accounting policies during the six months ended June 30, 2011, except for a change in the application of our accounting policy with respect to revenue recognition of the regulatory adjustment for income taxes paid and the recognition of pension expense under regulatory deferred accounting. For further discussion of this change in significant accounting policies and the impact of new accounting standards, see Note 2 below. We do not have any subsequent events to report.

Table of Contents

2. Significant Accounting Policies Update

Industry Regulation

In applying regulatory accounting principles, we capitalize or defer certain costs and revenues as regulatory assets and liabilities. At June 30, 2011 and 2010 and at December 31, 2010, the amounts deferred as regulatory assets and liabilities were as follows:

	Regulatory Assets		
Thousands	June 30, 2011	June 30, 2010	December 31, 2010
Current:			
Unrealized loss on derivatives(1)	$25,986	$34,463	$38,437
Pension and other postretirement benefit liabilities(2)	10,988	7,502	10,988
Other(3)	22,792	14,839	3,289
Total current	$59,766	$56,804	$52,714
Non-current:			
Unrealized loss on derivatives(1)	$9,202	$16,917	$17,022
Income tax asset	70,241	75,515	72,341
Pension and other postretirement benefit liabilities(2)	112,743	106,089	118,248
Environmental costs(4)	120,285	109,324	114,311
Other(3)	13,610	21,352	26,975
Total non-current	$326,081	$329,197	$348,897

	Regulatory Liabilities		
Thousands	June 30, 2011	June 30, 2010	December 31, 2010
Current:			
Gas costs payable	$17,538	$23,416	$15,583
Unrealized gain on derivatives(1)	4,433	1,495	2,245
Other(3)	3,813	4,613	-
Total current	$25,784	$29,524	$17,828
Non-current:			
Gas costs payable	$3,023	$2,218	$2,297
Unrealized gain on derivatives(1)	1,042	453	628
Accrued asset removal costs	259,593	246,839	252,941
Other(3)	2,045	2,075	2,165
Total non-current	$265,703	$251,585	$258,031

(1) Unrealized gain or loss on derivatives does not earn a rate of return or a carrying charge. These amounts are recoverable through utility rates as part of the Purchased Gas Adjustment mechanism when realized at settlement.

(2) Certain pension and other postretirement benefit liabilities of the utility are approved for regulatory deferral, including the approval of a pension cost balancing account to defer the effects of higher and lower pension expenses in future years. Such amounts are recoverable in rates, including an interest component, when recognized in pension expense or net periodic benefit cost (see Note 9).

7

Table of Contents

(3) Other primarily consists of deferrals and amortizations under other approved regulatory mechanisms. The accounts being amortized typically earn a rate of return or carrying charge.
(4) Environmental costs are related to certain utility sites that are approved for regulatory deferral. In Oregon we earn the utility's authorized rate of return as a deferred carrying charge on deferred account balances.

Revenue Recognition

Utility and non-utility revenues, which are derived primarily from the sale, transportation or storage of natural gas, are recognized upon the delivery of gas commodity or service to customers. Since 2007, utility net operating revenues have also included the recognition of a regulatory adjustment for income taxes paid pursuant to a legislative rule (commonly referred to as SB 408) in effect for certain gas and electric utilities in Oregon. Under SB 408, we were required to automatically implement a rate refund, or a rate surcharge, to utility customers on an annual basis. The refund or surcharge amount was based on the difference between income taxes paid and income taxes authorized to be collected in customer rates. We recorded the refund, or surcharge, each quarter from 2007 through 2010 based on the annual amount to be recognized. However, on May 24, 2011, SB 408 was repealed when the Oregon Governor signed Senate Bill 967 (SB 967) into law. SB 967, requires utilities to eliminate amounts accrued under SB 408 for the 2010 and 2011 tax years, thereby denying recovery by NW Natural of the surcharge related to 2010, which resulted in a one-time pre-tax charge of $7.4 million (or 17 cents per share) in the second quarter of 2011. With respect to the first quarter of 2011, there was substantial uncertainty surrounding the continuation of the legal requirements of SB 408 as of March 31, 2011, and accordingly we did not record an accrual for the estimated refund or surcharge so no amounts were required to be written off for 2011.

Pension Expense

Net periodic pension cost consists of service costs, interest costs, the expected returns on plan assets, and the amortization of actuarial gains and losses. Effective January 1, 2011, we began deferring a portion of our net periodic pension cost to a regulatory account on the balance sheet pursuant to OPUC approval of to defer certain pension expenses above or below the amount set in rates. See Note 9 for further information. As of June 30, 2011, the total amount deferred was $2.7 million.

New Accounting Standards

Adopted Standards

Fair Value Disclosures. In January 2010, the Financial Accounting Standards Board (FASB) issued authoritative guidance on new fair value measurements and disclosures. This guidance requires additional disclosures for fair value measurements that use significant assumptions not observable in active markets (i.e. level 3 valuations), including a rollforward schedule. These changes were effective for periods beginning after December 15, 2010; however, we elected to early adopt these disclosure requirements, as shown in Note 9 in our 2010 Form 10-K. The adoption of this standard did not have a material effect on our financial statement disclosures.

Recent Accounting Pronouncements

Fair Value Measurement. In May 2011, the FASB issued amendments to the authoritative guidance on fair value measurement. The amendments are primarily related to disclosure requirements, which go into effect for periods beginning after December 15, 2011. Early implementation is not allowed and we are currently assessing the impact on our financial statement disclosures.

Table of Contents

Comprehensive Income. In June 2011, the FASB issued authoritative guidance on the presentation of comprehensive income within the financial statements. An entity can elect to present items of net income and other comprehensive income in one continuous statement — referred to as the statement of comprehensive income — or in two separate, but consecutive, statements. These changes are effective for periods beginning after December 15, 2011 and early implementation is not permitted. We intend to present net income and other comprehensive income in one continuous statement.

3. Earnings Per Share

Basic earnings per share are computed using the weighted average number of common shares outstanding during each period presented. Diluted earnings per share are computed using the weighted average number of common shares outstanding plus the potential effects of the assumed exercise of stock options, and payment of estimated stock awards from other stock-based compensation plans that are outstanding, at the end of each period presented. Diluted earnings per share are calculated as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
Thousands, except per share amounts	2011	2010	2011	2010
Net income	$2,193	$6,888	$42,966	$50,496
Average common shares outstanding - basic	26,673	26,569	26,671	26,553
Additional shares for stock-based compensation plans	54	72	54	68
Average common shares outstanding - diluted	26,727	26,641	26,725	26,621
Earnings per share of common stock - basic	$0.08	$0.26	$1.61	$1.90
Earnings per share of common stock - diluted	$0.08	$0.26	$1.61	$1.90

For the three months ended June 30, 2011 and 2010, 8,946 and 5,052 common share equivalents, respectively, were excluded from the calculation of diluted earnings per share because the effect of these additional shares on the net income for both periods would have been anti-dilutive. For the six months ended June 30, 2011 and 2010, 3,883 and 1,364 common share equivalents, respectively, were excluded from the calculation of diluted earnings per share because the effect of these shares would have been anti-dilutive.

4. Segment Information

We operate in two primary reportable business segments, local gas distribution and gas storage. We also have other investments and business activities not specifically related to one of these two reporting segments, which we aggregate and report as “other.” We refer to our local gas distribution business as the “utility,” and our “gas storage” and “other” business segments as “non-utility.” Our gas storage segment includes NWN Gas Storage, a wholly-owned subsidiary of NWN Energy, Gill Ranch, a wholly-owned subsidiary of NWN Gas Storage, the non-utility portion of our Mist underground storage facility in Oregon (Mist) and third-party optimization services. Our “other” segment includes NNG Financial and our equity investment in PGH which is pursuing development of the Palomar pipeline project. For further discussion of our segments, see Note 4 in our 2010 Form 10-K.

Table of Contents

The following table presents summary financial information about the reportable segments for the three and six months ended June 30, 2011 and 2010. Inter-segment transactions were insignificant.

	Three Months Ended June 30,			
		Non-Utility		
Thousands	Utility	Gas Storage	Other	Total
2011				
Net operating revenues	$60,048	$7,197	$(13)	$67,232
Depreciation and amortization	15,946	1,600	-	17,546
Income from operations	9,667	3,017	(31)	12,653
Net income (loss)	1,090	1,315	(212)	2,193
2010				
Net operating revenues	$66,939	$5,206	$48	$72,193
Depreciation and amortization	15,691	335	-	16,026
Income from operations	16,271	3,925	22	20,218
Net income	4,641	2,122	125	6,888

	Six Months Ended June 30,			
		Non-Utility		
Thousands	Utility	Gas Storage	Other	Total
2011				
Net operating revenues	$189,210	$12,501	$29	$201,740
Depreciation and amortization	31,860	2,995	-	34,855
Income from operations	85,791	4,733	(9)	90,515
Net income (loss)	41,220	2,003	(257)	42,966
Total assets at June 30, 2011	2,247,349	252,393	22,252	2,521,994
2010				
Net operating revenues	$192,412	$10,617	$90	$203,119
Depreciation and amortization	31,257	670	-	31,927
Income from operations	92,853	8,436	39	101,328
Net income	45,533	4,623	340	50,496
Total assets at June 30, 2010	2,143,138	229,919	22,504	2,395,561
Total assets at December 31, 2010	$2,310,388	$282,945	$23,283	$2,616,616

5. Common Stock

We have a share repurchase program for our common stock under which we purchase shares on the open market or through privately negotiated transactions. We currently have Board authorization through May 2012 to repurchase up to an aggregate of 2.8 million shares, or up to $100 million. No shares of common stock were repurchased pursuant to this program during the six months ended June 30, 2011, but since inception in 2000 a total of 2.1 million shares have been repurchased at a total cost of $83.3 million.

Table of Contents

6. Stock-Based Compensation

We have several stock-based compensation plans, including a Long-Term Incentive Plan (LTIP), a Restated Stock Option Plan (Restated SOP) and an Employee Stock Purchase Plan. These plans are designed to promote stock ownership in NW Natural by employees and officers. For additional information on our stock-based compensation plans, see Part II, Item 8., Note 6, in the 2010 Form 10-K and current updates provided below.

Long-Term Incentive Plan. On February 23, 2011, 37,950 performance-based shares were granted under the LTIP, which include a market condition, based on target-level awards and a weighted-average grant date fair value of $25.25 per share. Fair value was estimated as of the date of grant using a Monte-Carlo option pricing model based on the following assumptions:

Stock price on valuation date	$45.74	
Performance term (in years)	3.0	
Quarterly dividends paid per share	$0.435	
Expected dividend yield	3.7	%
Dividend discount factor	0.8930	

Restated Stock Option Plan. On February 23, 2011, options to purchase 122,700 shares were granted under the Restated SOP, with an exercise price equal to the closing market price of $45.74 per share on the date of grant, vesting over a four-year period following the date of grant and a term of 10 years and 7 days. The weighted-average grant date fair value was $6.73 per share. Fair value was estimated as of the date of grant using the Black-Scholes option pricing model based on the following assumptions:

Risk-free interest rate	2.0	%
Expected life (in years)	4.5	
Expected market price volatility factor	24.5	%
Expected dividend yield	3.8	%
Forfeiture rate	3.1	%

As of June 30, 2011, there was $1.2 million of unrecognized compensation cost related to the unvested portion of outstanding Restated SOP awards expected to be recognized over a period extending through 2014.

7. Cost and Fair Value Basis of Long-Term Debt

Cost of Long-Term Debt

Our long-term debt consists of secured medium-term notes (MTNs) with maturity dates from 2012 through 2035, interest rates ranging from 3.95 percent to 9.05 percent, and a weighted-average coupon rate of 6.16 percent. For the six months ended June 30, 2011, we redeemed $10 million of MTNs. For more detail on our outstanding long-term debt, see Note 7 in our 2010 Form 10-K.

Table of Contents

Fair Value of Long-Term Debt

The following table provides an estimate of the fair value of our long-term debt, including current maturities of long-term debt, using market prices in effect on the valuation date. Because our debt outstanding does not trade in active markets, we used interest rates of other companies outstanding debt issues that actively trade and have similar credit ratings, terms and remaining maturities to estimate fair value of our long-term debt issues. These are significant other observable inputs, or level 2 inputs, in the fair value hierarchy.

	June 30,		December 31,
Thousands	2011	2010	2010
Carrying amount	$591,700	$636,700	$601,700
Estimated fair value	$678,281	$728,172	$690,126

8. Comprehensive Income

Items excluded from net income and charged directly to stockholders' equity are included in accumulated other comprehensive income (loss), net of tax. The amount of accumulated other comprehensive loss in stockholders' equity is $6.3 million and $5.8 million as of June 30, 2011 and 2010, respectively, which is related to employee benefit plan liabilities. The following table provides a reconciliation of net income to total comprehensive income for the six months ended June 30, 2011 and 2010.

	Three Months Ended June 30,		Six Months Ended June 30,	
Thousands	2011	2010	2011	2010
Net income	$2,193	$6,888	$42,966	$50,496
Amortization of employee benefit plan liability, net of tax	146	98	292	196
Total comprehensive income	$2,339	$6,986	$43,258	$50,692

Table of Contents

9. Pension and Other Postretirement Benefit Costs

The following tables provide the components of net periodic benefit cost for our company-sponsored qualified and non-qualified defined benefit pension plans and other postretirement benefit plans:

	Three Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits	
Thousands	2011	2010	2011	2010
Service cost	$1,900	$1,773	$168	$156
Interest cost	4,526	4,492	343	342
Expected return on plan assets	(4,456)	(4,563)	-	-
Amortization of net actuarial loss	2,692	1,768	68	8
Amortization of prior service costs	88	204	49	49
Amortization of transition obligations	-	-	103	103
Net periodic benefit cost	4,750	3,674	731	658
Amount allocated to construction	(1,251)	(947)	(229)	(207)
Amount deferred to regulatory balancing account(1)	(1,329)	-	-	-
Net amount charged to expense	$2,170	$2,727	$502	$451

	Six Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits	
Thousands	2011	2010	2011	2010
Service cost	$3,799	$3,546	$336	$312
Interest cost	9,053	8,983	687	685
Expected return on plan assets	(8,912)	(9,127)	-	-
Amortization of net actuarial loss	5,384	3,536	136	15
Amortization of prior service costs	176	410	98	98
Amortization of transition obligations	-	-	206	206
Net periodic benefit cost	9,500	7,348	1,463	1,316
Amount allocated to construction	(2,486)	(1,900)	(455)	(415)
Amount deferred to regulatory balancing account(1)	(2,659)	-	-	-
Net amount charged to expense	$4,355	$5,448	$1,008	$901

(1) Effective January 1, 2011, the OPUC approved the deferral of certain pension expenses above or below the amount set in rates, with recovery of these deferred amounts through the implementation of a balancing account, which includes the expectation of lower pension expenses in future years. Our recovery of deferred pension expense balances includes accrued interest at the utility's authorized rate of return.

See Part II, Item 8., Note 9, in the 2010 Form 10-K for more information about our pension and other postretirement benefit plans.

Table of Contents

In addition to the company-sponsored defined benefit plans referred to above, we contribute to a multiemployer pension plan for our bargaining unit employees in accordance with our collective bargaining agreement, known as the Western States Office and Professional Employees International Union Pension Fund (Western States Plan). The cost of this plan is in addition to pension expense in the table above. The Western States Plan has reported an accumulated funding deficit for the current plan year and remains in critical status. The Western States Plan trustees adopted a rehabilitation plan that reduced benefit accrual rates and adjustable benefits for active employee participants and increased future employer contribution rates. These changes are expected to improve the funding status of the plan. We made contributions totaling $0.2 million to the Western States Plan for both the six months ended June 30, 2011 and 2010. If we withdraw and the plan is underfunded, we could be assessed a withdrawal liability which is not currently recognized on the balance sheet in accordance with accounting rules for multiemployer plans. Currently, we have no intent to withdraw from the plan, so we have not recorded a withdrawal liability.

Employer Pension Contributions

In the six months ended June 30, 2011, we made cash contributions totaling $16.4 million to our qualified defined benefit pension plans. We also expect to make additional contributions of between $5 million and $7 million to these qualified plans over the last six months of 2011, plus we expect to make ongoing benefit payments under our unfunded, non-qualified pension plans and other postretirement benefit plans. For more information see Part II, Item 8., Note 9, in the 2010 Form 10-K.

10. Income Tax

The effective income tax rate for the six months ended June 30, 2011 and 2010 varied from the combined federal and state statutory tax rates principally due to the following:

	June 30,			
	2011		2010	
Federal statutory tax rate	35.0	%	35.0	%
Increase (decrease):				
Current state income tax, net of federal tax benefit	4.5	%	4.8	%
Amortization of investment and energy tax credits	(0.4	) %	(0.4	) %
Differences required to be flowed-through by regulatory commissions	1.6	%	1.4	%
Gains on company and trust-owned life insurance	(0.6	) %	(0.4	) %
Other - net	0.3	%	0.1	%
Effective income tax rate	40.4	%	40.5	%

The decrease in our effective tax rate for the six months ended June 30, 2011 compared to the same period in 2010 was negligible and primarily due to a change in state income tax rates. See Note 10 in our 2010 Form 10-K.

Table of Contents

11. Property, Plant and Equipment

The following table sets forth the major classifications of our property, plant and equipment and accumulated depreciation as of June 30, 2011 and 2010 and December 31, 2010:

Thousands	June 30, 2011	June 30, 2010	December 31, 2010
Utility plant in service	$2,281,407	$2,218,660	$2,247,952
Utility construction work in progress	32,814	30,086	29,324
Less: Accumulated depreciation	730,199	700,202	710,214
Utility plant-net	1,584,022	1,548,544	1,567,062
Non-utility plant in service	290,035	66,862	290,038
Non-utility construction work in progress	7,891	167,218	9,088
Less: Accumulated depreciation	14,730	10,530	12,025
Non-utility plant-net	$283,196	$223,550	$287,101
Total property, plant and equipment	$1,867,218	$1,772,094	$1,854,163

12. Gas Reserves and Other Investments

Our gas reserves are stated at cost, net of regulatory amortization, with the associated deferred tax benefits recorded as liabilities on the balance sheet. Other investments include financial investments in life insurance policies, which are accounted for at fair value, and equity investments in certain partnerships and limited liability companies, which are accounted for under the equity or cost methods. See Part II, Item 8., Note 12, in the 2010 Form 10-K for more detail on our investments.

Gas Reserves

We signed agreements with Encana Oil & Gas (USA) Inc. (Encana) to develop physical gas reserves that are expected to supply a portion of our utility customers' requirements over the next 30 years. The volume of gas produced and allocated to NW Natural under the agreements will increase in the early years as we continue to invest in drilling, with volumes expected to peak at about 13 percent of our utility's gas supply requirement in gas year 2015-2016. Over the first 10 years of the agreement (2011-2020), volumes are expected to average approximately 8 to 10 percent of the annual requirements of our utility customers. Under the agreements, we expect to invest approximately $45 million to $55 million per year for five years, and our total investment is expected to be about $250 million.

In approving the agreements, the OPUC determined that our Company's costs under the agreements will be recovered on an ongoing basis through its annual Purchased Gas Adjustment (PGA) mechanism, including the deferral and incentive sharing process for the commodity cost of gas. Annually, we will forecast the amounts related to gas reserve costs and volumes expected, and variances between forecast and actual up to $10 million will be subject to the normal PGA incentive sharing mechanism, which currently is set at 10 percent of the variance amount that would be recognized in earnings. Variances in excess of $10 million, both negative and positive, will be entirely deferred and passed through to customer rates. As part of the decision by the OPUC to approve the agreements, we have agreed to file a general rate case in Oregon no later than December 31, 2011.

Encana began drilling in May 2011 under our agreements, and we are currently receiving gas from our interests in a section of the gas field. Our net investment at June 30, 2011 is $12.1 million, net of deferred taxes totaling $4 million.

15

Table of Contents

Variable Interest Entity Analysis. As of June 30, 2011, we have determined that the arrangements with Encana qualify as a VIE and that we are not the primary beneficiary of these activities as defined by the authoritative guidance related to consolidations. We account for our investment in the VIE on the cost basis and it is included under gas reserves on our balance sheet. Our maximum loss exposure related to the VIE is limited to our investment balance.

Palomar

PGH is a development stage variable interest entity. Palomar, a wholly-owned subsidiary of PGH, is pursuing the development of a new gas transmission pipeline that would provide an interconnection with our utility distribution system. PGH is owned 50 percent by NWN Energy and 50 percent by TransCanada American Investments Ltd., an indirect wholly-owned subsidiary of TransCanada Corporation.

Variable Interest Entity Analysis. As of June 30, 2011, we updated our VIE analysis and determined that we are not the primary beneficiary of PGH's activities as defined by the authoritative guidance related to consolidations. Therefore, we account for our investment in PGH and the Palomar project under the equity method, which is included in other investments on our balance sheet. Our maximum loss exposure related to PGH is limited to our equity investment balance, less our share of any cash or other assets available to us as a 50 percent owner.

Impairment Analysis. Our investments in nonconsolidated entities accounted for under the equity method are reviewed for impairment when circumstances or events indicate a potential loss in value may have occurred, and on an annual basis following updates to our corporate planning assumptions. When it is determined that a loss in value is other than temporary, an impairment charge is recognized for the difference between the investment's carrying value and its estimated fair value. Fair value is based on quoted market prices when available, or on the present value of expected discounted future cash flows. Differing assumptions could affect the timing and amount of an impairment recorded in any period.

In March 2011, our investment in PGH was reviewed for impairment when Palomar withdrew its original application with the Federal Energy Regulatory Commission (FERC) for a proposed natural gas pipeline in Oregon. At the same time, Palomar informed FERC that it intended to re-file an application later this year or in 2012 to reflect changes in the project scope, which was expected to eliminate the western portion of the proposed pipeline and align the revised project with the region's current and future gas infrastructure needs. Palomar is working with customers in the Pacific Northwest to further understand their gas transportation needs. Palomar expects to obtain commercial support for its revised pipeline proposal, and then file a new FERC certificate application by the end of next year.

During the second quarter of 2011, we re-assessed our equity investment in Palomar assets related to the western portion of the pipeline and determined that these costs were impaired, and as a result we recorded a pre-tax charge of $0.3 million for our share of the project. Our remaining investment balance in Palomar consists of costs related to the east zone, of which the investment balance at June 30, 2011 is $14.4 million. We reviewed these east zone costs for impairment based on the current status of the project, including Palomar's plans to conduct an open season and re-file a revised application with FERC later this year or in 2012. Based on our review, we determined that our remaining equity investment was not impaired because the fair value of expected cash flows from planned development of the eastern portion of the pipeline project exceeds our equity investment. However, if we learn later that the project is not viable or will not go forward, then we could be required to recognize an impairment charge of up to approximately $14.2 million based on the current amount of our equity investment net of cash and working capital at Palomar. We will continue to monitor and update our impairment analysis as needed.

Table of Contents

13. Derivative Instruments

We enter into swap, option and various option combinations for the purpose of hedging natural gas. We primarily use these derivative financial instruments to manage commodity prices related to our natural gas purchase requirements. A small portion of the derivatives are also related to foreign currency exchange transactions.

In the normal course of business, we enter into indexed-price physical forward natural gas commodity purchase (gas supply) contracts to meet the requirements of core utility customers. We also enter into financial derivatives, up to prescribed limits, to hedge price variability related to the physical gas supply contracts. Derivatives entered into prudently for future gas years prior to our annual PGA filing receive regulatory deferred accounting treatment. Derivative contracts entered into after the annual PGA rate was set on November 1, 2010 that are for the current gas contract year are subject to our PGA incentive sharing mechanism, which, during the current PGA year, provides for a 90 percent deferral of any gains and losses as regulatory assets or liabilities, with the remaining 10 percent recognized on the income statement. Most of our commodity hedging for the upcoming gas year is completed prior to the start of each gas year, and these hedge prices are included in our annual PGA filing.

The following table discloses the income statement presentation for the unrealized gains and losses from our derivative instruments for the six months ended June 30, 2011 and 2010. All of our currently outstanding derivative instruments are related to regulated utility operations as illustrated by the derivative gains and losses being deferred to the balance sheet accounts in accordance with regulatory accounting.

	Three Months Ended			
	June 30, 2011		June 30, 2010	
Thousands	Natural gas commodity(1)	Foreign currency (2)	Natural gas commodity(1)	Foreign currency (2)
Cost of sales	$ 3,631	$ -	$ 8,471	$ -
Other comprehensive income (loss)	-	(196)	-	(356)
Less:				
Amounts deferred to regulatory accounts on balance sheet	(3,631)	196	(8,471)	356
Total impact on earnings	$ -	$ -	$ -	$ -

	Six Months Ended			
	June 30, 2011		June 30, 2010	
Thousands	Natural gas commodity(1)	Foreign currency (2)	Natural gas commodity(1)	Foreign currency (2)
Cost of sales	$ (30,119)	$ -	$ (49,093)	$ -
Other comprehensive income (loss)	-	406	-	(339)
Less:				
Amounts deferred to regulatory accounts on balance sheet	30,119	(406)	49,093	339
Total impact on earnings	$ -	$ -	$ -	$ -

(1) Unrealized gain (loss) from natural gas commodity hedge contracts is recorded in cost of sales and reclassified to regulatory deferral accounts on the balance sheet.

(2) Unrealized gain (loss) from foreign currency exchange contracts is recorded in other comprehensive income, and reclassified to regulatory deferral accounts on the balance sheet.

17

Table of Contents

We had no collateral posted with our counterparties as of June 30, 2011 or 2010. We attempt to minimize the potential exposure to collateral calls by our counterparties to manage our liquidity risk. Based on our current credit ratings, most counterparties allow us credit limits ranging from $25 million to $50 million before collateral postings are required. Our collateral call exposure is set forth under credit support agreements, which generally contain credit limits. We also could be subject to collateral call exposure where we have agreed to provide adequate assurance, which is not specific as to the amount of credit limit allowed, but could potentially require additional collateral in the event of a material adverse change. Based upon current contracts outstanding, which reflect unrealized losses of $29.7 million at June 30, 2011, we have estimated the level of collateral demands, with and without potential adequate assurance calls, using current gas prices and various downgrade credit rating scenarios for NW Natural as follows:

		Credit Rating Downgrade Scenarios			
Thousands	(Current Ratings) A+/A3	BBB+/Baa1	BBB/Baa2	BBB-/Baa3	Speculative
With Adequate Assurance Calls	$ -	$-	$-	$1,966	$16,900
Without Adequate Assurance Calls	$ -	$-	$-	$1,966	$13,892

In the three and six months ended June 30, 2011, we realized net losses of $8.7 million and $29.6 million, respectively, from the settlement of natural gas hedge contracts at maturity, which were recorded as increases to the cost of gas, compared to net losses of $14.6 million and $20.8 million, respectively, for the three and six months ended June 30, 2010. The exchange rate in all foreign currency forward purchase contracts is included in our purchased cost of gas at settlement; therefore, no gain or loss is recorded from the settlement of those contracts.

We are exposed to derivative credit and liquidity risk primarily through securing fixed price natural gas commodity swaps to hedge the risk of price increases for our natural gas purchases made on behalf of our customers. For more information on our derivative instruments, see Note 13 in our 2010 Form 10-K.

Fair Value

In accordance with fair value accounting, we include nonperformance risk in calculating fair value adjustments. This includes a credit risk adjustment based on the credit spreads of our counterparties when we are in an unrealized gain position, or on our own credit spread when we are in an unrealized loss position. Our assessment of non-performance risk is generally derived from the credit default swap market and from bond market credit spreads. The impact of the credit risk adjustments for all outstanding derivatives was immaterial to the fair value calculation at June 30, 2011. As of June 30, 2011 and 2010 and December 31, 2010, the fair value was $29.7 million, $49.4 million and $52.6 million, respectively, using significant other observable, or level 2, inputs. We have used no level 3 inputs in our derivative valuations. We also did not have any transfers between level 1 or level 2 during the six months ended June 30, 2011 and 2010.

14. Commitments and Contingencies

Environmental Matters

We own, or previously owned, properties that may require environmental remediation or action. We accrue all material loss contingencies relating to these properties that we believe to be probable of assertion and reasonably estimable. We continue to study and evaluate the extent of our potential environmental liabilities, but due to the numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several site investigations, in some cases, we may not be able to reasonably estimate the high end of the range of possible loss. In those cases we have disclosed the nature of the potential loss and the fact that the high end of the range cannot be reasonably estimated.

Table of Contents

We regularly review our environmental liability for each site where we may be exposed to remediation responsibilities. The costs of environmental remediation are difficult to estimate. A number of steps are involved in each environmental remediation effort, including site investigations, remediation, operations and maintenance, monitoring and site closure. Each of these steps may, over time, involve a number of alternative actions, each of which can change the course and scope of the effort. Many of these steps are dependent upon the approval and direction of federal and state environmental regulators. The policies, determinations and directions of the regulators may develop and change over time and different regulators may take different positions on the various steps, creating further uncertainty as to the timing and scope of remediation activities. In certain cases, in addition to us, there are a number of other potentially responsible parties, each of which, in proceedings and negotiations with other potentially responsible parties and regulators, may influence the course and scope of the remediation effort. The allocation of liabilities among the potentially responsible parties is often subject to dispute and can be highly uncertain. The events giving rise to environmental liabilities often occurred many decades ago, which complicates the determination of allocating liabilities among potentially responsible parties. Site investigations and remediation efforts often develop slowly over many years. In addition, disputes may arise between potentially responsible parties and regulators as to the severity of particular environmental matters and what remediation efforts are appropriate. These disputes could lead to adversarial administrative proceedings or litigation, with uncertain outcomes.

We estimate the range of loss for environmental liabilities using current technology, enacted laws and regulations, industry experience gained at similar sites and an assessment of the probable level of involvement and financial condition of other potentially responsible parties. Unless there is an estimate within this range of possible losses that is more likely than other cost estimates, we record the liability at the lower end of this range. It is likely that changes in these estimates and ranges will occur throughout the remediation process for each of these sites due to uncertainty concerning our responsibility, the complexity of environmental laws and regulations and the selection of compliance alternatives. The status of each of the sites currently under investigation is provided below.

Gasco site. We own property in Multnomah County, Oregon that is the site of a former gas manufacturing plant that was closed in 1956 (Gasco site). The Gasco site has been under investigation by us for environmental contamination under the Oregon Department of Environmental Quality’s (ODEQ) Voluntary Clean-Up Program. In June 2003, we filed a Feasibility Scoping Plan which outlined a range of remedial alternatives for the most contaminated portion of the Gasco site. In December 2004, we submitted an Ecological and Human Health Risk Assessment to ODEQ, and in May 2007 we completed a revised Remedial Investigation Report and submitted it to DEQ for review.

In 2007, we also submitted a Focused Feasibility Study (FFS) for the groundwater source control portion of the Gasco site, which ODEQ conditionally approved in March 2008, subject to the submission of additional information. We provided that information to ODEQ and are now working with the agency on the final design for the source control system. Based on the information currently available for groundwater source control at the Gasco site and our current assumptions regarding remediation, we have estimated a range of liability between $11 million and $30 million, for which we have recorded an accrued liability of $11.8 million at June 30, 2011. The estimated range of liability will be reassessed when ODEQ makes a final source control design decision.

In addition to groundwater source control, we signed a joint Order on Consent with the Environmental Protection Agency (EPA), which requires the design of remedial action for sediments from the Gasco site. This design project is underway. We also have other investigation and clean-up work, including work on the uplands portion of the Gasco site, that we expect to be required. For the sediments project and the other investigation and clean-up work, we have recorded an additional accrued liability of $37.8 million, which reflects the low end of the range of potential liability. We accrued at the low end because no amount within the range is considered to be more likely than another, and the high end of the range cannot reasonably be estimated.

Siltronic site. We previously owned property adjacent to the Gasco site that now is the location of a manufacturing plant owned by Siltronic Corporation (the Siltronic site). We are currently conducting an investigation of manufactured gas plant wastes on the uplands at this site for the ODEQ. The liability accrued at June 30, 2011 for the Siltronic site is $0.9 million, which is at the low end of the range of potential liability because no amount within the range is considered to be more likely than another, and the high end of the range cannot reasonably be estimated.

Table of Contents

Portland Harbor site. In 1998, the ODEQ and the EPA completed a study of sediments in a 5.5-mile segment of the Willamette River (Portland Harbor) that includes an area adjacent to the Gasco and Siltronic sites. The Portland Harbor was listed by the EPA as a Superfund site in 2000 and we were notified that we are a potentially responsible party. We then joined with other potentially responsible parties, referred to as the Lower Willamette Group, to fund environmental studies in the Portland Harbor. Subsequently, the EPA approved a Programmatic Work Plan, Field Sampling Plan and Quality Assurance Project Plan for the Portland Harbor Remedial Investigation/Feasibility Study (RI/FS), completion of which is scheduled for 2011. The EPA and the Lower Willamette Group are conducting focused studies on approximately nine miles of the lower Willamette River, including the 5.5-mile segment previously studied by the EPA. In August 2008, we signed a cooperative agreement to participate in a phased natural resource damage assessment, with the intent to identify what, if any, additional information is necessary to estimate further liabilities sufficient to support an early restoration-based settlement of natural resource damage claims. As of June 30, 2011, we have a liability accrued of $7.6 million for this site, which is at the low end of the range of the potential liability because no amount within the range is considered to be more likely than another, and the high end of the range cannot reasonably be estimated.

Central Service Center site. In 2006, we received notice from the ODEQ that our Central Service Center in southeast Portland (Central Service Center site) was assigned a high priority for further environmental investigation. Previously there were three manufactured gas storage tanks on the premises. The ODEQ believes there could be site contamination associated with releases of condensate from stored manufactured gas as a result of historic gas handling practices. In the early 1990s, we excavated waste piles and much of the contaminated surface soils and removed accessible waste from some of the abandoned piping. In early 2008, we received notice that this site was added to the ODEQ’s list of sites where releases of hazardous substances have been confirmed and to its list where additional investigation or cleanup is necessary. We are currently performing an environmental investigation of the property with the ODEQ’s Independent Cleanup Pathway. As of June 30, 2011, we have a liability accrued of $0.5 million for investigation at this site. The estimate is at the low end of the range of potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot reasonably be estimated.

Front Street site. The Front Street site was the former location of a gas manufacturing plant we operated. It is near but outside the geographic scope of the current Portland Harbor site sediment studies. The EPA directed the Lower Willamette Group to collect a series of surface and subsurface sediment samples off the river bank adjacent to where that facility was located. Based on the results of that sampling, the EPA notified the Lower Willamette Group that additional sampling would be required. As the Front Street site is upstream from the Portland Harbor site, the EPA agreed that it could be managed separately from the Portland Harbor site under ODEQ authority. Work plans for source control investigation and a historical report were submitted to ODEQ and initial studies were completed. In 2010, ODEQ required additional studies which are underway. As of June 30, 2011, we have an estimated liability accrued of $0.8 million for the study of the sediments and riverbank groundwater and soils at the site. The estimate is at the low end of the range of potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot reasonably be estimated.

Oregon Steel Mills site. See “Legal Proceedings,” below.

Table of Contents

Accrued Liabilities Relating to Environmental Sites. The following table summarizes the accrued liabilities relating to environmental sites at June 30, 2011 and 2010 and December 31 2010:

	Current Liabilities			Non-Current Liabilities		
Thousands	June 30, 2011	June 30, 2010	Dec. 31, 2010	June 30, 2011	June 30, 2010	Dec. 31, 2010
Gasco site	$10,593	$7,996	$11,366	$38,965	$43,522	$38,921
Siltronic site	836	724	720	71	358	201
Portland Harbor site	2,161	1,836	2,304	5,426	6,875	5,784
Central Service Center site	5	5	5	543	510	510
Front Street site	-	72	1	823	166	1,097
Other sites	-	-	-	132	117	108
Total	$13,595	$10,633	$14,396	$45,960	$51,548	$46,621

Regulatory and Insurance Recovery for Environmental Costs. In May 2003, the Public Utility Commission of Oregon (OPUC) approved our request to defer unreimbursed environmental costs associated with certain named sites, including those described above. Beginning in 2006, the OPUC granted us additional authorization to accrue interest on deferred environmental cost balances, subject to an annual demonstration that we have maximized our insurance recovery or made substantial progress in securing insurance recovery for unrecovered environmental expenses. Through a series of extensions, the authorized cost deferral and interest accrual was extended through January 2010. We have filed a request with the OPUC to extend this deferral, and that request is still pending. In addition, we filed a request with the Washington Utilities and Transportation Commission (WUTC) in January 2011 to defer certain environmental costs associated with services provided to Washington customers. We received an order from the WUTC on June 30, 2011 granting that request. Environmental costs related to Washington will be deferred starting January 26, 2011, with cost recovery to be determined in a future rate case.

On a cumulative basis, we have recognized a total of $107.2 million for environmental costs, including legal, investigation, monitoring and remediation costs, including $4.9 million paid and expensed prior to regulatory deferral order approval. At June 30, 2011, we had a regulatory asset of $120.3 million, which includes $49.4 million of total paid expenditures to date, $59.6 million for additional environmental costs expected to be paid in the future and accrued interest of $16.7 million, partially offset by $5.4 million of environmental costs expensed in prior years. See table below.

In December 2010, NW Natural commenced litigation against certain of its historical liability insurers in Multnomah County Circuit Court, State of Oregon, Case Number 1012-17532. The defendants include Associated Electric & Gas Insurance Services Limited, Allianz Global Risk US Insurance Company, Certain Underwriters at Lloyd's, London, certain London market insurance companies and other insurance companies. In the suit, NW Natural alleges that the defendant insurance companies issued third party liability insurance policies to NW Natural and that the defendants have breached the terms of those policies by failing to indemnify NW Natural for liabilities arising from environmental contamination at certain sites caused or alleged to be caused by its historical operations. NW Natural seeks damages for the losses it has incurred to date, as well as declaratory relief for additional losses it expects to incur in the future. In addition to seeking recovery of our environmental costs from our insurers, we believe recovery of the remainder of our deferred charges, if any, is probable through the regulatory process. Our regulatory asset will be reduced by the amount of any corresponding insurance recoveries. We continue to anticipate that our overall insurance recovery effort will extend over several years.

Table of Contents

Our regulatory recovery of environmental cost deferrals may be initiated in the next general rate case; however, we do not expect to have concluded our insurance recovery efforts by that point, so we are not currently able to estimate the amount of recovery expected through the implementation of new rates from the upcoming general rate proceeding. We will reclassify a portion of the deferred environmental costs to current when we anticipate insurance recovery or recovery of costs in rates within the next 12 months. The following table summarizes the non-current regulatory assets relating to environmental sites at June 30, 2011 and 2010 and December 31, 2010:

	Non-Current Regulatory Assets		
Thousands	June 30, 2011	June 30, 2010	December 31, 2010
Gasco site	$78,270	$71,531	$74,205
Siltronic site	3,502	3,068	3,174
Portland Harbor site	35,379	32,712	33,940
Central Service Center site	612	551	553
Front Street site	2,067	1,056	2,020
Other sites	455	406	420
Total	$120,285	$109,324	$114,312

Legal Proceedings

We are subject to claims and litigation arising in the ordinary course of business. Although the final outcome of any of these legal proceedings cannot be predicted with certainty, including the matter described below, we do not expect that the ultimate disposition of any of these matters will have a material effect on our financial condition, results of operations or cash flows.

Oregon Steel Mills site. In 2004, NW Natural was served with a third-party complaint by the Port of Portland (Port) in a Multnomah County Circuit Court case, Oregon Steel Mills, Inc. v. The Port of Portland. The Port alleges that in the 1940s and 1950s petroleum wastes generated by our predecessor, Portland Gas & Coke Company, and 10 other third-party defendants were disposed of in a waste oil disposal facility operated by the United States or Shaver Transportation Company on property then owned by the Port and now owned by Oregon Steel Mills. The complaint seeks contribution for unspecified past remedial action costs incurred by the Port regarding the former waste oil disposal facility as well as a declaratory judgment allocating liability for future remedial action costs. No date has been set for trial and discovery is ongoing. Although the final outcome of this proceeding cannot be predicted with certainty, we do not expect that the ultimate disposition of this matter will have a material effect on our financial condition, results of operations or cash flows.

Table of Contents

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following is management's assessment of Northwest Natural Gas Company's (NW Natural) financial condition, including the principal factors that affect results of operations. The discussion refers to our consolidated activities for the three and six months ended June 30, 2011 and 2010. Unless otherwise indicated, references in this discussion to "Notes" are to the Notes to Consolidated Financial Statements in this report. This discussion should be read in conjunction with our 2010 Annual Report on Form 10-K (2010 Form 10-K).

The consolidated financial statements include the accounts of NW Natural and its direct and indirect wholly-owned subsidiaries which include: Gill Ranch Storage, LLC (Gill Ranch), NW Natural Energy, LLC (NWN Energy), NW Natural Gas Storage, LLC (NWN Gas Storage), and NNG Financial Corporation (NNG Financial). These statements also include accounts related to an equity investment in Palomar Gas Holdings, LLC (PGH), which is pursuing the development of a proposed natural gas pipeline through its wholly-owned subsidiary Palomar Gas Transmission LLC (Palomar). These accounts make up our regulated local gas distribution business, our regulated gas storage businesses, and other regulated and non-regulated investments primarily engaged in energy-related businesses. In this report, the term "utility" is used to describe our regulated gas distribution business (local distribution company), and the term "non-utility" is used to describe our regulated gas storage businesses (gas storage) as well as our other regulated and non-regulated investments and business activities (other). For a further discussion of our business segments, see Note 4.

In addition to presenting results of operations and earnings amounts in total, certain measures are expressed in cents per share. These amounts reflect factors that directly impact earnings. We believe this per share information is useful because it enables readers to better understand the impact of these factors on consolidated earnings. All references in this section to earnings per share are on the basis of diluted shares (see Part II, Item 8., Note 3, "Earnings Per Share," in our 2010 Form 10-K). We use such non-GAAP (i.e. non-generally accepted accounting principles) measures in analyzing out financial performance and believe that they provide useful information to our investors and creditors in evaluating our financial condition and results of operations.

Executive Summary

Highlights of consolidated results for the second quarter of 2011 as compared to the same period in 2010 include:

- Consolidated earnings of $2.2 million or 8 cents per share in the second quarter of 2011, as compared to $6.9 million and 26 cents in the second quarter of 2010;
- Net income from utility operations decreased $3.6 million, from $4.6 million in 2010 to $1.1 million in 2011, largely due to a $7.4 million pre-tax charge related to a legislative change in Oregon that repealed Senate Bill (SB) 408;
- Net income from gas storage operations decreased $0.8 million, from $2.1 million in 2010 to $1.3 million in 2011, primarily reflecting the weak market values for contract storage and optimization services;
- Net operating revenues (margin) decreased $5.0 million or 7 percent over 2010, with utility margin down $6.9 million due to the one-time SB 408 charge and gas storage margin up $2.0 million from Gill Ranch first year costs including depreciation;
- Operating expenses increased $2.6 million or 5 percent over 2010, which was largely attributed to increases in Gill Ranch's operations and maintenance and depreciation and amortization;
- Income tax expense decreased $3.0 million in 2011 compared to 2010, primarily due to lower pre-tax consolidated earnings;
- Cash flow from operating activities in 2011 was $168.7 million, for an increase of $64.5 million or 62 percent over 2010;

- Utility customers increased by approximately 5,600 over the last 12 months, for an annual growth rate of 0.8 percent compared to 1.0 percent a year ago; and
  - The utility business began investing in long-term gas reserves as a part of its gas purchasing strategy.

Issues, Challenges and Performance Measures

Economic Environment. Weakness in the local, national and global economies has continued to impact utility customer growth, the demand for natural gas, and the value of natural gas storage services. Our utility's annual customer growth rate was 0.8 percent at June 30, 2011, as compared to 0.9 percent at March 31, 2011 and 1.0 percent at June 30, 2010. Although total delivered volumes to utility customers in the second quarter of 2011 increased 4 percent, we are still faced with unemployment rates around 10 percent in our service territories of Oregon and southwest Washington and a sluggish business environment. Despite these challenges, we believe we are well positioned to continue adding utility customers due to lower natural gas prices, a relatively low market penetration rate, our ongoing efforts to convert homes to natural gas, and the potential for environmental initiatives that could favor natural gas use in our region.

Managing Gas Prices and Supplies. Our gas acquisition strategy is regularly updated to secure sufficient supplies of natural gas to meet the needs of our utility customers and to hedge gas prices so that we can effectively manage costs, reduce price volatility and maintain a competitive advantage. With recent developments in drilling technologies and substantial access to supplies from shale gas formations around the U.S. and in Canada, the supply outlook for North American natural gas has increased dramatically, which is contributing to lower and more stable gas prices. The Purchased Gas Adjustment (PGA) mechanisms in Oregon and Washington, along with our own gas price hedging strategies and gas supplies in storage, enable us to reduce earnings risk exposure for the company and secure lower gas costs for our customers. These lower gas prices, can help strengthen natural gas' competitive advantage compared to other fuels. See discussion of Utility Investment in Gas Reserves below under Strategic Opportunities.

We typically hedge approximately 75 percent of our anticipated year-round sales volumes based on normal weather. We entered the 2010-11 gas year (November 1, 2010 – October 31, 2011) hedged at a level of approximately 77 percent of our forecasted volumes, including 62 percent financially hedged and 15 percent physically hedged with gas in storage.

We recently entered into an agreement with Encana to invest in gas reserves, which will increase our physical gas hedge position in future gas years. Including estimates of gas to be produced from this investment, we are currently hedged at a level of approximately 68 percent for the 2011-12 gas year, reflecting 48 percent financially hedged and 20 percent physically hedged with storage and gas reserves. The 20 percent physically hedged is comprised of 17 percent for normal storage levels going into the winter heating season (including anticipated summer purchases), plus 3 percent for estimated production from gas reserves.

Additionally, we are currently hedged at a level of approximately 30 percent for the 2012-13 gas year, including 8 percent financially hedged and 22 percent physically hedged with storage and gas reserves. The 22 percent physically hedged is comprised of 16 percent for normal storage levels plus 6 percent for gas reserves. Our current hedge levels for the next two gas years are estimates and subject to change based on actual load volumes that are dependent on weather and economic conditions. Also, our storage levels may increase or decrease based on storage expansion or storage recall by the utility. As for gas reserve levels, these are estimates of production and are subject to change based on possible unforeseen events that could impact the speed of drilling and the volume of production.

Although stable gas prices provide opportunities to manage costs for our utility customers, they also present challenges for our gas storage business by lowering the value of, and reducing the demand for, storage services thus affecting our ability to sign customer contracts for longer terms at favorable prices.

Environmental Costs. We accrue material environmental loss contingencies related to our properties that require environmental investigation or remediation. Due to numerous uncertainties surrounding the preliminary nature of investigations or the developing nature of remediation requirements, actual costs could vary significantly from our loss estimates. As a regulated utility, we are allowed to defer certain costs pursuant to regulatory decisions. In 2010 and prior years, we were authorized by the Public Utility Commission of Oregon (OPUC) to defer certain environmental costs, and to seek recovery of those amounts in future rates to customers. For 2011, we have a request pending before the OPUC to approve an extension of the deferral order for certain environmental costs. The Company is also seeking recovery of these costs under insurance policies. Any amounts collected from insurance are expected to offset amounts that may otherwise be collected from customers. Ultimate recovery of environmental costs, either from regulated utility rates or from insurance, will depend on our ability to effectively manage these costs and demonstrate they were prudently incurred. Recovery may vary significantly from amounts currently recorded as regulatory assets, and amounts not recovered would be required to be charged to income in the period they were deemed to be unrecoverable. See Results of Operations—Regulatory Matters—Rate Mechanisms—Regulatory Recovery for Environmental Costs below, Note 14 in this report and Note 15 in our 2010 Form 10-K.

Table of Contents

Climate Change. See Part II, Item 7., "Executive Summary - Issues, Challenges and Performance Measures—Climate change," in our 2010 Form 10-K for a discussion of the effect of climate change on our business.

Performance Measures. In order to deal with the challenges affecting our businesses, we annually review and update our strategic plan to map our course over the next several years. Our plan includes strategies for: further improving our utility gas distribution services and operations; growing our non-utility gas storage business; investing in natural gas infrastructure when necessary to support the needs of our region; and maintaining a leadership role within the gas utility industry by addressing long-term energy policies and pursuing business opportunities that support clean energy technologies. We intend to measure our performance and monitor progress on certain metrics including, but not limited to: earnings per share growth; total shareholder return; return on invested capital; utility return on equity; utility customer satisfaction; utility margin; utility capital and operations and maintenance expense per customer; and non-utility earnings before interest, taxes, depreciation and amortization (non-utility EBITDA).

Strategic Opportunities

Business Process Improvements. To address the current economic and competitive challenges, we continue to evaluate and implement business strategies to improve efficiencies. Our goal is to develop, integrate, consolidate and streamline operations and support our employees with new technology tools.

Gas Storage Operations. The Company has developed gas storage facilities in Oregon and California. In California, Gill Ranch began operating during the fourth quarter of 2010, offering storage services to the California market at market-based rates, subject to California Public Utilities Commission (CPUC) regulation including, but not limited to, service terms and conditions, tariff regulations, and security issuances. Gill Ranch currently is designed as a 20 Bcf facility, of which 75 percent is owned by NW Natural, but is expandable to a total capacity of 40 Bcf of which NW Natural would own 50 percent. Due to increasing supplies and price stability of natural gas in North America, and declining demand for natural gas due to current economic conditions, storage values are expected to remain low in the near term, which will likely affect the prices at which Gill Ranch is able to contract and the timing of future storage expansions. For more information, see Note 4 in this report and Part II, Item 7., "2011 Outlook—Strategic Opportunities," in our 2010 Form 10-K.

In Oregon, we own storage facilities at Mist which serve the Pacific Northwest storage markets. These markets also are negatively impacted by lower gas prices and lack of gas price volatility, but less so than in California and many other markets around the country because of limited availability of storage capacity in the Northwest. In 2011 and 2012, we expect to continue planning for possible expansion at our gas storage facilities near Mist in anticipation of increased demand for electric generation in the Pacific Northwest. Currently we do not have a set timeline for the next expansion at Mist, but we believe the timeframe for completion would be no earlier than 2013 or 2014. In the meantime, we will continue to monitor the market demand and work on preliminary design and project planning, which will ultimately require the development of storage wells, potentially a second compression station and additional pipeline gathering facilities that could enable future storage expansions.

Pipeline Diversification. Currently, our utility and Mist gas storage operations depend on a single bi-directional interstate transmission pipeline to ship gas supplies. Palomar, a wholly-owned subsidiary of PGH, is pursuing the development of a new gas transmission pipeline that would provide an interconnection with our utility distribution system. PGH is owned 50 percent by NWN Energy and 50 percent by TransCanada American Investments Ltd., an indirect wholly-owned subsidiary of TransCanada Corporation. The Palomar pipeline was originally proposed with an east and a west segment, but Palomar currently plans to design an east-only pipeline to serve our utility customers as well as the growing natural gas markets in Oregon and other parts of the Pacific Northwest. The proposed pipeline would be regulated by the Federal Energy Regulatory Commission (FERC).

25

Table of Contents

In March 2011, Palomar withdrew its original application with FERC for a natural gas pipeline in Oregon, but at the same time informed FERC that it intends to file a new application later this year or in 2012, after it has conducted an open season and obtained commercial support for the east segment pipeline, which is approximately 110 miles long.

Utility Investment in Gas Reserves. In addition to hedging gas prices with financial derivative contracts over the next few years, we recently signed an agreement with Encana Oil & Gas (USA) Inc. (Encana) to develop physical gas supplies that are expected to supply a portion of our utility customers' requirements over a period of about 30 years. During the first 10 years of the agreements, we forecast the volumes of gas received under the Encana agreements to provide approximately 8 to 10 percent of the average annual requirements of our utility customers. Under the agreements, we expect to invest approximately $45 million to $55 million per year for five years, with our total investment expected to be about $250 million. Encana will assign to us a working interest in leases to certain sections of the Jonah gas field, located near Rock Springs, Wyoming. The sections include both future and currently producing wells. Operation of the wells will be governed by a joint operating agreement under which Encana will be the operator and we will pay our proportionate share of operating costs.

On April 28, 2011, the OPUC issued an order approving the Encana gas reserve investment, which provides for the recovery of the costs plus a rate base return on our investment through the annual PGA mechanism, including the deferral process for the commodity cost of gas. See Results of Operations—Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment below. Annually, a forecast will be established for the amounts related to costs and volumes expected, and variances between forecasted and actual will be subject to the PGA incentive sharing in Oregon, up to a maximum variance of $10 million (for a discussion of the incentive sharing provision, see "Results of Operations – Regulatory Matters – Rate Mechanisms" below). Any variances in excess of $10 million, both negative and positive, will be deferred and passed through to customers in future rates at 100 percent. As part of the decision by the OPUC, we agreed to file a general rate case in Oregon no later than December 31, 2011.

Consolidated Earnings and Dividends

Three months ended June 30, 2011 compared to June 30, 2010:

For the three months ended June 30, 2011, we had net income of $2.2 million, or 8 cents per share, compared to net income of $6.9 million, or 26 cents per share, for the same period last year.

The primary factors contributing to decreased second quarter consolidated net income were:

- an $8.5 million decrease related to the regulatory adjustment of income taxes paid, which consisted of a one-time $7.4 million write-off in the second quarter of 2011 related to the amount accrued for 2010, plus the $1.1 million amount accrued in the second quarter of 2010 while the SB 408 rules were still in effect. See "Results of Operations - Business Segments - Utility Operations - Regulatory Adjustment for Income Taxes Paid," below for further discussion; and
- a $0.9 million decrease in income from operations related to non-utility storage at Mist and Gill Ranch.

Partially offsetting the above factors were:

- a $3.0 million decrease in income tax expense due to lower taxable income; and
- a $1.6 million increase in utility net operating revenues (margin), including the affects of our weather normalization and decoupling mechanisms, primarily due to colder weather and customer growth.

Table of Contents

Six months ended June 30, 2011 compared to June 30, 2010:

Net income was $43 million, or $1.61 per share, for the six months ended June 30, 2011, compared to $50.5 million, or $1.90 per share, for the same period last year.

The primary factors contributing to the $7.5 million decrease in net income were:

- a $6.1 million decrease related to a refund of property taxes in 2010, which is reflected by an operating expense increase of $5.2 million under general taxes and a $1.9 million decrease in interest income under other income partially offset by a decrease of $1.0 million under operations and maintenance;
- an $11.2 million decrease related to the effects of the 2010 regulatory adjustment of income taxes paid and the write-off in 2011 due to new legislation (see "Results of Operations - Business Segments - Utility Operations - Regulatory Adjustment for Income Taxes Paid," below); and
- a $3.7 million decrease in income from operations related to our gas storage segment, primarily reflecting low contract storage values at Gill Ranch, decreased third party optimization revenue, and relatively lower contract storage values at Mist.

Partially offsetting the above factors were:

- a $7.7 million increase in utility margin attributable to an increase in residential and commercial customer use, which reflect gains from colder weather and customer growth; and
- a $5.2 million decrease in income tax expense due to lower taxable income.

Dividends paid on our common stock were 43.5 cents per share in the second quarter of 2011, compared to 41.5 cents per share in the second quarter of 2010. The Board of Directors declared a quarterly dividend on our common stock of 43.5 cents per share, payable on August 15, 2011, to shareholders of record on July 29, 2011. The current indicated annual dividend rate is $1.74 per share.

Application of Critical Accounting Policies and Estimates

In preparing our financial statements using generally accepted accounting principles in the United States of America (GAAP), management exercises judgment in the selection and application of accounting principles, including making estimates and assumptions that affect reported amounts of assets, liabilities, revenues, expenses and related disclosures in the financial statements. Management considers our critical accounting policies to be those which are most important to the representation of our financial condition and results of operations and which require management's most difficult and subjective or complex judgments, including accounting estimates that could result in materially different amounts if we reported under different conditions or used different assumptions. Our most critical estimates and judgments include accounting for:

- regulatory cost recovery and amortizations;
- revenue recognition;
- derivative instruments and hedging activities;
- pensions and postretirement benefits;
- income taxes; and
- environmental contingencies.

There have been no material changes to the information provided in the 2010 Form 10-K with respect to the application of critical accounting policies and estimates (see Part II, Item 7., "Application of Critical Accounting Policies and Estimates," in the 2010 Form 10-K), except as indicated below under Revenue Recognition and Pension

Expense.

Table of Contents

Revenue Recognition

Utility and non-utility revenues, which are derived primarily from the sale, transportation or storage of natural gas, are recognized upon the delivery of gas commodity or service to customers. Since 2007, utility revenues have included the recognition of a regulatory adjustment for income taxes paid pursuant to a legislative rule (commonly referred to as SB 408) in effect for certain gas and electric utilities in Oregon. Under SB 408, we were required to automatically implement a rate refund, or a rate surcharge, to utility customers on an annual basis. The refund or surcharge amount was based on the difference between income taxes paid and income taxes authorized to be collected in customer rates. We recorded the refund, or surcharge, each quarter since 2007 based on the annual amount to be recognized. On May 24, 2011 the Oregon Governor signed Senate Bill 967 (SB 967), which in effect repealed SB 408 and the change was effective immediately. The new law requires utilities in Oregon, to reverse amounts accrued for the 2010 and 2011 tax years. For the tax year 2010, the Company recorded a one-time pre-tax charge to earnings in the second quarter of 2011 in the amount of $7.4 million ($4.4 million or 17 cents after tax). For the tax year 2011, there was substantial uncertainty surrounding the continuation of the legal requirements of SB 408, and accordingly the Company had not recognized any additional revenues in 2011. See “Results of Operations—Business Segments - Utility Operations—Regulatory Adjustment for Income Taxes Paid,” below for a further discussion.

Pension Expense

Net periodic benefit cost consists of service costs, interest costs, the expected returns on plan assets, and the amortization of actuarial gains and losses. Effective January 1, 2011, we began deferring a portion of our net periodic pension cost to a regulatory account on the balance sheet pursuant to OPUC approval of annual pension expenses above or below the amount set in rates. See Note 9 for further information. As of June 30, 2011, the total amount deferred was $2.7 million.

Management has discussed its current estimates and judgments used in the application of critical accounting policies with the Audit Committee of the Board. Within the context of our critical accounting policies and estimates, management is not aware of any reasonably likely events or circumstances that would result in materially different amounts being reported, except for the item discussed above under Revenue Recognition. For a description of recent accounting pronouncements that could have an impact on our financial condition, results of operations or cash flows, see Note 2.

Results of Operations

Regulatory Matters

Regulation and Rates

We are subject to regulation with respect to, among other matters, rates and systems of accounts set by the OPUC, Washington Utilities and Transportation Commission (WUTC), FERC, and with respect to Gill Ranch, the CPUC. The OPUC, WUTC and CPUC also regulate our issuance of securities. In 2011, approximately 90 percent of our utility gas volumes were delivered to, and utility operating revenues were derived from, Oregon customers, and the balance was from Washington customers. Future earnings and cash flows from utility operations will be determined largely by the Oregon and Washington economies in general, by the pace of growth in the residential and commercial markets in particular, and by our ability to remain price competitive, control expenses, and obtain reasonable and timely regulatory recovery for our utility gas costs, primarily operating and maintenance expenses and investment costs made in utility plant. See Part II, Item 7., “Results of Operations—Regulatory Matters,” in the 2010 Form 10-K.

Rate Mechanisms

Purchased Gas Adjustment. Rate changes are established for the utility each year under PGA mechanisms in Oregon and Washington to reflect changes in the expected cost of natural gas commodity purchases, including contract gas purchase prices, gas prices hedged with financial derivatives or physical gas reserves, gas inventory prices, interstate pipeline demand costs, the application of temporary rate adjustments to amortize balances in deferred regulatory accounts and the removal of temporary rate adjustments effective for the previous year.

Table of Contents

In October 2010, the OPUC and WUTC approved PGA rate changes effective on November 1, 2010. The effect of these rate changes was to decrease the average monthly bills of Oregon and Washington residential customers by 2 percent. This was our second consecutive year of rate decreases.

Under the current PGA mechanism in Oregon, there is an incentive sharing provision whereby we are required to select each year either an 80 percent deferral or a 90 percent deferral of higher or lower actual gas costs compared to estimated PGA prices, such that the impact on current earnings from the incentive sharing is either 20 percent or 10 percent of the difference between actual and estimated gas costs, respectively. In addition to the gas cost incentive sharing mechanism, we are subject to an annual earnings review to determine if the utility is earning above its allowed return on equity (ROE) threshold. If utility earnings exceed a specific ROE level, then 33 percent of the amount above that level are required to be deferred for refund to customers. Under this provision, if we select the 80 percent deferral option, then we retain all of our earnings up to 150 basis points above the currently authorized ROE. If we select the 90 percent deferral option, then we retain all of our earnings up to 100 basis points above the currently authorized ROE. We selected the 90 percent deferral option for both the 2009-2010 and the 2010-2011 PGA years. The ROE threshold is subject to adjustment annually based on movements in long-term interest rates. For calendar years 2009 and 2010, the ROE threshold after adjustment for long-term interest rates was 11.5 percent and 11.02 percent, respectively. No amounts were required to be refunded to customers as a result of the 2009 utility earnings review, but based upon utility results for 2010 and the first two quarters of 2011, we accrued approximately $0.5 million and $0.4 million, respectively, for refund to customers in future rates.

In Oregon, we are subject to an annual earnings review to determine if the utility’s earnings are above a certain ROE threshold. If utility earnings exceed that threshold, then 33 percent of the amount above that level is deferred for refund to customers.

In the OPUC proceeding through which our earnings for 2010 are determined for purposes of the annual earnings review, OPUC Staff and other parties are disputing our determination of amounts that must to be deferred and refunded to customers. Specifically, they are challenging our determination that amounts received in 2010 from a refund of property tax expense related to prior years should be removed from the 2010 test period under normalization requirements established by the OPUC. Although we believe it is probable that the OPUC will rule in our favor on this dispute, the financial impact of an adverse ruling could increase the estimated refund to customers by up to $3 million, which we would be required to record as an additional charge to earnings.

There has been no change to the Washington PGA mechanism under which we defer 100 percent of the higher or lower actual gas costs and pass that difference through to customers as an adjustment to future rates.

Regulatory Recovery for Environmental Costs. The OPUC has authorized us to defer environmental costs associated with certain named sites and to accrue interest on environmental cost balances, subject to an annual demonstration that we have maximized our insurance recovery or made substantial progress in securing insurance recovery for unrecovered environmental expenses. We have filed a request for an extension of this deferral and expect to receive this authorization during the next couple of months. See Note 14. In January 2011, we filed a request with the WUTC to defer environmental costs, if any, that are incurred in connection with services provided to Washington customers. On June 30, 2011 we received an order granting approval of that request effective January 26, 2011. Cost recovery of deferred amounts will be determined in a future rate case.

Pension Deferral. Effective January 1, 2011, the OPUC approved our request to defer annual pension expenses above the amount set in rates, with recovery of these deferred amounts through the implementation of a balancing account, which includes the expectation of lower pension expenses in future years. Our recovery of deferred balances includes accrued interest on the account balance at the utility’s authorized rate of return. The estimated reduction to operations and maintenance expense for 2011 is estimated to be in the range of $4 to $5 million, with $2.7 million being deferred through June 30, 2011. Future years' deferrals will depend on changes in plan assets and projected benefit liabilities, as well as our pension contributions.

For a discussion of other rate mechanisms, see Part II, Item 7., "Results of Operations—Regulatory Matters—Rate Mechanisms" in our 2010 Form 10-K.

Business Segments - Utility Operations

Our utility margin results are largely affected by customer growth and to a certain extent by changes in weather and customers' gas usage patterns, with a significant portion of our earnings being derived from natural gas sales to residential and commercial customers. In Oregon, we have a conservation tariff that adjusts margin revenues to offset changes resulting from increases or decreases in residential and commercial customers' gas usage. We also have a weather normalization mechanism in Oregon that adjusts customer bills up or down to offset changes in margin resulting from above- or below-average temperatures during the winter heating season. Both mechanisms are designed to reduce the volatility of our utility earnings and customer charges. For more information on our weather mechanism, see Regulatory Matters—Rate Mechanisms—Weather Normalization in our 2010 Form 10-K.

Three months ended June 30, 2011 compared to June 30, 2010:

Utility operations resulted in net income of $1.1 million, or 4 cents per share, in the second quarter of 2011 compared to net income of $4.6 million, or 17 cents per share, in the second quarter of 2010. The increase in utility margin from colder weather during the second quarter of 2011 was more than offset by a reduction in margin of $8.5 million in the second quarter of 2011 for the repeal of the regulatory adjustment for income taxes paid, including the $1.0 million of margin recorded in the second quarter of 2010. Total utility volumes sold and delivered in the second quarter of this year increased by 4 percent over last year.

Our weather normalization mechanism adjusted residential and commercial margins down by $4.8 million for the second quarter of 2011 based on temperatures that were 10 percent colder than last year and 38 percent colder than average, compared to a margin decrease of $1.9 million for the second quarter of 2010 when temperatures were 25 percent colder than average. Our decoupling mechanism adjusted residential and commercial margins up by $2.2 million in the second quarter of 2011, compared to a margin increase of $1.1 million in 2010.

Six months ended June 30, 2011 compared to June 30, 2010:

In the six months ended June 30, 2011, utility operations contributed net income of $41.2 million or $1.54 per share, compared to $45.5 million or $1.71 per share in 2010. Total utility volumes sold and delivered in the six months ended June 30, 2011 increased by 14 percent over last year primarily due to 17 percent colder weather, while total utility margin decreased by $3.2 million, or 2 percent, primarily due to a reduction in margin in the six months ended 2011 for the repeal of the regulatory adjustment for income taxes paid, compared to $4.0 million of increased margin recorded a year earlier for the impact of SB 408 in effect during 2010. The decrease in utility margin was partially offset by a $7.7 million increase in residential and commercial margins, after weather and decoupling mechanism adjustments, primarily related to the benefits of colder weather in the first six months of this year and customer growth (see "Residential and Commercial Sales," below).

During the six months ended June 30, 2011 our weather normalization mechanism adjusted residential and commercial margins down by $10.6 million based on temperatures that were 17 percent colder than last year and 14 percent colder than average, compared to a margin increase of $11.6 million last year when temperatures were 3 percent warmer than average. Our decoupling mechanism adjusted residential and commercial margins up by $10.9 million in the six months ended June 30, 2011, compared to a margin increase of $9.0 million in the six months ended June 30, 2010.

Table of Contents

The following tables summarize the composition of gas utility volumes, revenues and margin:

Thousands, except degree day and customer data	Three Months Ended June 30, 2011	2010	Favorable/ (Unfavorable) 2011 vs. 2010
Utility volumes - therms:			
Residential sales	78,377	72,094	6,283
Commercial sales	51,608	47,837	3,771
Industrial - firm sales	8,476	8,625	(149)
Industrial - firm transportation	31,906	31,156	750
Industrial - interruptible sales	14,519	13,924	595
Industrial - interruptible transportation	57,866	59,751	(1,885)
Total utility volumes sold and delivered	242,752	233,387	9,365
Utility operating revenues - dollars:			
Residential sales	$86,628	$84,002	$ 2,626
Commercial sales	45,176	44,126	1,050
Industrial - firm sales	6,382	6,782	(400)
Industrial - firm transportation	1,520	1,382	138
Industrial - interruptible sales	8,027	8,196	(169)
Industrial - interruptible transportation	2,278	1,981	297
Regulatory adjustment for income taxes paid(1)	(7,451)	1,034	(8,485)
Other revenues	11,385	9,599	1,786
Total utility operating revenues	153,945	157,102	(3,157)
Cost of gas sold	90,054	86,292	(3,762)
Revenue taxes	3,843	3,871	28
Utility margin	$60,048	$66,939	$ (6,891)
Utility margin:(2)			
Residential sales	$43,766	$41,098	$ 2,668
Commercial sales	17,230	16,552	678
Industrial - sales and transportation	6,840	7,119	(279)
Miscellaneous revenues	1,526	1,303	223
Gain (loss) from gas cost incentive sharing	87	496	(409)
Other margin adjustments	632	105	527
Margin before regulatory adjustments	70,081	66,673	3,408
Weather normalization adjustment	(4,751)	(1,901)	(2,850)
Decoupling adjustment	2,169	1,133	1,036
Regulatory adjustment for income taxes paid(1)	(7,451)	1,034	(8,485)
Utility margin	$60,048	$66,939	$ (6,891)
Customers - end of period:			
Residential customers	611,564	606,323	5,241
Commercial customers	62,532	62,171	361
Industrial customers	906	911	(5)
Total number of customers - end of period	675,002	669,405	5,597
Actual degree days	944	857	
Percent colder (warmer) than average weather(3)	38%	25%	

31

Table of Contents

Thousands, except degree day and customer data	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010	Favorable/ (Unfavorable) 2011 vs. 2010
Utility volumes - therms:			
Residential sales	253,307	205,954	47,353
Commercial sales	151,575	126,693	24,882
Industrial - firm sales	19,113	18,778	335
Industrial - firm transportation	67,596	63,767	3,829
Industrial - interruptible sales	31,758	30,248	1,510
Industrial - interruptible transportation	120,817	121,350	(533)
Total utility volumes sold and delivered	644,166	566,790	77,376
Utility operating revenues - dollars:			
Residential sales	$ 285,402	$ 253,611	$ 31,791
Commercial sales	140,489	124,201	16,288
Industrial - firm sales	15,338	15,400	(62)
Industrial - firm transportation	3,111	2,818	293
Industrial - interruptible sales	18,510	18,577	(67)
Industrial - interruptible transportation	4,588	3,900	688
Regulatory adjustment for income taxes paid(1)	(7,165)	4,018	(11,183)
Other revenues	11,399	15,640	(4,241)
Total utility operating revenues	471,672	438,165	33,507
Cost of gas sold	270,664	234,840	(35,824)
Revenue taxes	11,798	10,913	(885)
Utility margin	$ 189,210	$ 192,412	$ (3,202)
Utility margin:(2)			
Residential sales	$ 128,018	$ 107,502	$ 20,516
Commercial sales	49,788	42,260	7,528
Industrial - sales and transportation	14,450	14,242	208
Miscellaneous revenues	3,110	2,976	134
Gain from gas cost incentive sharing	1,122	695	427
Other margin adjustments	(395)	86	(481)
Margin before regulatory adjustments	196,093	167,761	28,332
Weather normalization adjustment	(10,612)	11,634	(22,246)
Decoupling adjustment	10,894	8,999	1,895
Regulatory adjustment for income taxes paid(1)	(7,165)	4,018	(11,183)
Utility margin	$ 189,210	$ 192,412	$ (3,202)
Actual degree days	2,918	2,484	
Percent colder (warmer) than average weather(3)	14 %	(3) %	

(1) Regulatory adjustment for income taxes paid is described below.

(2) Amounts reported as margin for each category of customers are net of cost of gas sold and revenue taxes.

(3) Average weather represents the 25-year average degree days, as determined in our last Oregon general rate case.

32

Table of Contents

Residential and Commercial Sales

The primary factors that impact results of operations in the residential and commercial markets are customer growth, seasonal weather patterns, energy prices, competition from other energy sources and economic conditions in our service areas. Typically, 80 percent or more of our utility's operating revenues on an annual basis are derived from gas sales to weather-sensitive residential and commercial customers. Although variations in temperatures between periods will affect volumes of gas sold to these customers, the effect on margin and net income is significantly reduced by our weather normalization mechanism in Oregon where about 90 percent of our customers are served. For more information on our weather mechanism, see Regulatory Matters—Rate Mechanisms—Weather Normalization in our 2010 Form 10-K.

Three months ended June 30, 2011 compared to June 30, 2010:

The primary factors contributing to changes in residential and commercial volumes and operating revenues in the second quarter of this year as compared to the same period last year were:

- sales volumes increased 8 percent due to weather that was 10 percent colder than 2010;
- utility operating revenues increased $3.7 million or 3 percent due to colder weather and customer growth; and
- utility margin increased $1.5 million or 3 percent, including weather normalization, which benefits customers when weather is colder than normal, and decoupling adjustments.

Six months ended June 30, 2011 compared to June 30, 2010:

The primary changes that impacted margin from residential and commercial sales for the six months ended June 30, 2011 compared to June 30, 2010 were as follows:

- utility sales volumes were 22 percent higher, primarily reflecting 17 percent colder weather;
- utility operating revenues increased $48.1 million or 13 percent primarily due to increased volumes from colder weather, partially offset by lower customer rates; and
- utility margin increased $7.7 million or 5 percent reflecting increased volumes from residential and commercial customer growth and colder weather, which was partially offset by weather normalization adjustments that benefit customer bills when weather is colder than normal.

Industrial Sales and Transportation

Operating revenues from industrial customers include the commodity cost component of gas sold under sales service but not under transportation service. Therefore, operating revenues from industrial customers can increase or decrease when customers switch between sales service and transportation service, but generally our margins from these customers are unaffected by these changes because we do not include a profit mark-up for the cost of gas. As such, we believe volumes delivered and margins are better measures of performance for the industrial sector.

Three months ended June 30, 2011 compared to June 30, 2010:

The primary factors that impacted second quarter results from industrial sales and transportation markets were as follows:

- volumes delivered to industrial customers decreased by 0.7 million therms, or less than 1 percent; and
- margin decreased $0.3 million, or 4 percent.

Table of Contents

Six months ended June 30, 2011 compared to June 30, 2010:

The primary factors that impacted year-to-date results from industrial sales and transportation markets were as follows:

- volumes delivered to industrial customers increased 5.1 million therms, or 2 percent, due to a slight increase in energy demand, with the majority of the increased volumes attributable to the manufacturing sector; and
- margin from industrial customers increased $0.2 million, or 1 percent primarily due to the increase in volumes.

Regulatory Adjustment for Income Taxes Paid

Until 2011, Oregon law required certain regulated natural gas and electric utilities to annually review the amount of income taxes collected in rates from utility operation and compare it to the amount the utility actually pays to taxing authorities. Under this law, if we paid less in income taxes related to utility operations than we collected from Oregon utility customers, then we were required to refund the excess to our Oregon utility customers. Conversely, if we paid more in income taxes than we collected from Oregon utility customers, then we were required to collect a surcharge from Oregon utility customers.

The Company’s income taxes resulted in a surcharge every year since SB 408 became law in 2006. For the 2009 tax year, the OPUC approved the Company’s recovering $5.1 million plus interest from customers. For the 2010 tax year, we had estimated the difference between income taxes paid and the amounts collected in rates of $7.1 million, excluding interest. The 2010 surcharge to customers was primarily driven by lower property taxes as well as by utility operating margins, including gains from gas cost savings related to our PGA incentive sharing.

However, SB 967 repealed the regulatory adjustment for income taxes paid for the 2010 tax year and all years thereafter. It also requires the OPUC to make decisions in future ratemaking proceedings on the amounts of income taxes to be recovered in rates. SB 967 was signed into law in May 2011, and we concluded that the regulatory asset for the SB 408 surcharge was impaired and recorded a charge of $7.4 million including accrued interest in the second quarter of 2011. For the three and six months ended June 30, 2010 we had recognized $1.0 million and $4.0 million of pre-tax income from SB 408.

For further discussion, see “Revenue Recognition” above under Application of Critical Accounting Policies and Estimates.

Other Revenues

Other revenues include miscellaneous fee income as well as revenue adjustments reflecting deferrals to, or amortizations from, regulatory asset or liability accounts, except for gas cost deferrals which flow through the cost of gas sold.

Three months ended June 30, 2011 compared to June 30, 2010:

Other revenues were $11.4 million in the second quarter of 2011, an increase of $1.8 million over the second quarter of 2010, with the increase due to a $1.0 million increase in our decoupling deferral, a $1.2 million increase in our estimated credits due to utility customers from our regulatory incentive sharing mechanism related to gas storage services at Mist, and $1.3 million for WARM deferrals, offset in part by regulatory amortization decreases of $1.4 million.

Six months ended June 30, 2011 compared to June 30, 2010:

Other revenues were $11.4 million in the six months ended June 30, 2011, a decrease of $4.2 million over the same period of 2010, reflecting a $4.3 million decrease in the decoupling amortization, a $0.4 million accrual for the earnings test adjustment, and a decrease in other regulatory amortizations of $2.2 million partially offset by a $1.2 million accrual for estimated credits due to utility customers from our regulatory incentive sharing mechanism related to gas storage services at Mist, and an increase in the decoupling deferral of $1.9 million.

Table of Contents

Cost of Gas Sold

Cost of gas sold includes gas purchases, gas drawn from storage inventory, gains and losses from commodity hedges, pipeline demand costs, seasonal demand cost balancing adjustments, regulatory gas cost deferrals, production from gas reserves and company gas use. Our regulated utility does not generally earn a profit, or incur a loss, on gas commodity purchases. The OPUC and WUTC require natural gas commodity costs to be billed to customers at the same cost incurred, or expected to be incurred, by the utility. However, under the PGA mechanism in Oregon, our net income can be affected by differences between actual and expected gas costs, which occur primarily because of market fluctuations and volatility affecting unhedged gas purchases (see "Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment," above). We use natural gas commodity-based hedge contracts (derivatives), primarily fixed-price commodity swaps, consistent with our financial derivatives policies to help manage our exposure to rising gas prices. Gains and losses from these financial hedge contracts are generally included in our PGA prices and normally do not impact net income because the hedged prices are usually 100 percent passed through to customers in annual rate changes, subject to a regulatory prudency review. However, utility hedge contracts entered into after the annual PGA rates are set in Oregon can impact net income because we would be required to share in any gains or losses compared to the corresponding commodity prices built into rates in the PGA. In Washington, cost of gas sold does not affect our margins or net income because 100 percent of the actual gas costs, including hedge gains and losses allocated to Washington gas sales, are passed through in customer rates (see Part II, Item 7., "Application of Critical Accounting Policies and Estimates—Accounting for Derivative Instruments and Hedging Activities," and "Results of Operations—Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment," in the 2010 Form 10-K, and Note 13 in this report).

Three months ended June 30, 2011 compared to June 30, 2010:

- total cost of gas sold increased $3.8 million, or 4 percent, mainly due to a 4 percent increase in sales volumes;
- the average gas cost collected through rates, excluding customer refunds for accumulated gas cost savings from prior quarters, decreased 3 percent from 61 cents per therm in 2010 to 59 cents per therm in 2011, primarily reflecting the lower prices that were passed on to customers through the PGA effective November 1, 2010; and
- hedge losses totaling $8.7 million were realized and included in cost of gas sold this quarter, compared to $14.6 million of hedge losses in the same period of 2010.

The effect on operating results from our gas cost incentive sharing mechanism was a margin gain of $0.1 million in the second quarter of 2011, compared to a margin gain of $0.5 million for the second quarter of 2010.

Six months ended June 30, 2011 compared to June 30, 2010:

- total cost of gas sold increased $35.8 million, or 15 percent, due to a 14 percent increase in total sales volumes coupled with a 3 percent decrease in the average cost of gas sold per therm;
- the average gas cost collected through rates decreased from 62 cents per therm in 2010 to 60 cents per therm in 2011, primarily reflecting lower gas prices that were passed on through PGA rate decreases effective November 1, 2009 and 2010; and
- hedge losses totaling $29.6 million were realized and included in cost of gas sold for the six months ended June 30, 2011, compared to $20.8 million of hedge losses in the same period of 2010. Since the underlying hedge prices were included in our PGA billing rates, these losses did not impact margin or net income.

The amount recorded to pre-tax income from the shareholders' portion of our gas cost incentive sharing mechanism was a margin contribution of $1.1 million in the first half of 2011 compared to $0.7 million in 2010. For a discussion of our gas cost incentive sharing mechanism, see "Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment," above.

Table of Contents

Business Segments - Gas Storage

Our gas storage segment primarily consists of the acquisition, development, operation and management of natural gas storage facilities. As of June 30, 2011, we owned and operated non-utility investments at our Mist underground storage facility in Oregon and at our Gill Ranch underground storage facility in California. Construction of the Gill Ranch storage facility was completed and placed into service during the fourth quarter of 2010. Our gas storage segment also includes asset optimization services using unused gas storage and transportation capacity.

Three months ended June 30, 2011 compared to June 30, 2010:

For the three months ended June 30, 2011, we earned $1.3 million, or 5 cents per share, compared to $2.1 million, or 8 cents per share, for the same period in 2010. Even though the gas storage segment margin increased $2.0 million over last year due to revenues from the new Gill Ranch facility, the $0.8 million decrease in net income over 2010 is partially due to lower third-party storage optimization revenues and net losses at Gill Ranch from first year costs, including depreciation, and low storage contract values.

Six months ended June 30, 2011 compared to June 30, 2010:

For the six months ended June 30, 2011, our gas storage segment earned $2 million, or 8 cents per share, compared to $4.6 million, or 18 cents per share, for the same period in 2010. This decrease was partly due to a downturn in revenues from firm storage and optimization services and primarily related to net losses at Gill Ranch due to first year costs, including depreciation, and low storage contract values.

Gas storage net operating revenues (margin) increased $1.9 million to $12.5 million for the six months ended June 30, 2011. This increase in margin is primarily due to Gill Ranch's revenues of $3.7 million, partially offset by a decrease in firm contract and third-party optimization revenues of $1.8 million at Mist.

Business Segments - Other

Our other business segment consists primarily of NNG Financial's investment in KB Pipeline, our investment in PGH which in turn has invested in the Palomar pipeline project, and our other non-utility investments and business activities. NNG Financial had total assets of $1.0 million and $1.2 million as of June 30, 2011 and 2010, respectively, primarily reflecting a non-controlling interest in the Kelso-Beaver pipeline. Our net equity investment in PGH as of June 30, 2011 and 2010 was $14.4 million and $14.8 million, respectively, reflecting a Palomar $0.3 million write-down of costs related to the projects' west pipeline segment. In aggregate, earnings from our other business segment for the six months ended June 30, 2011 and 2010 were a net loss of $0.3 million and net income of $0.3 million, respectively. See Note 4 in the 2010 Form 10-K and in this report.

Consolidated Operations

Operations and Maintenance

Three months ended June 30, 2011 compared to June 30, 2010:

Operations and maintenance expense was $30.4 million in 2011, compared to $28.4 million in 2010, a increase of $2 million or 7 percent. The primary factors contributing to the increase were:

- a $1.8 million increase for operating expenses at Gill Ranch;
-

a $0.6 million increase in utility employee compensation expense primarily due to increases in training and pipeline integrity programs;

- a $0.5 million increase in utility bad debt expense primarily due to higher revenues billed to utility customers (see discussion below); and

Table of Contents

- a $0.3 million increase in utility damage claims.

Partially offsetting the above factors were:

- a $1.7 decrease in accrued performance bonuses at the utility based on below-target results compared to last year; and
- a $0.3 million decrease in utility pension expense due to the effects of the new regulatory deferral of pension expense authorized by the OPUC (see below for further discussions).

Six months ended June 30, 2011 compared to June 30, 2010:

Consolidated operations and maintenance expense was $61.5 million in 2011, compared to $59.1 million in 2010, a increase of $2.4 million or 4 percent. The following summarizes the major factors that contributed to changes in operations and maintenance expense for the six months ended June 30, 2011 compared to June 30, 2010:

- a $3.0 million increase for operating expenses at Gill Ranch;
- a $0.4 million increase in utility employee compensation expense related to additional training expense and pipeline system integrity work;
- a $0.3 million increase in utility bad debt expense primarily due to higher revenues (see discussion below); and
- a $0.3 million increase in utility health care costs and other employee benefit expense.

Partially offsetting the above factors were:

- a $1.0 million decrease in utility consulting and legal fees last year related to our successful property tax appeal;
- a $1.0 million decrease in accrued performance bonuses at the utility based on below-target results compared to last year; and
- a $0.5 million decrease in utility pension expense due to the effects of the new regulatory deferral of pension expense authorized by the OPUC (see below for further discussion).

Our bad debt expense as a percent of revenues was 0.24 percent for the twelve months ended June 30, 2011, compared to 0.19 percent for the same period last year. The increase in our bad debt expense ratio was largely due to lower than normal expense ratio in 2010 due to improved collections and recoveries of delinquent account balances. Despite the modest increase, we believe bad debt losses are comparable to last year, and credit risks are still elevated due to the weak economy and high unemployment rates. Higher customer usage from colder weather these past few months may increase our exposure to credit losses over the remainder of this year.

Effective January 1, 2011, the OPUC approved the deferral of utility pension costs related to NW Natural’s qualified defined benefit plans for operations and maintenance expense above the amount currently recovered in rates, which was set in our last general rate case. The pension expense deferral is recorded to a regulatory asset balancing account, which we expect to result in an estimated $4 to $5 million cumulative amount for 2011. So far, we have deferred $2.7 million of pension expense in the first six months of 2011, which, when netted with pension expense, resulted in a $0.5 million decrease to operations and maintenance expense compared to the same period in 2010. For further explanation of the pension balancing account, see “Regulatory Matters—Rate Mechanisms—Pension Deferral,” above.

General Taxes

Three months ended June 30, 2011 compared to June 30, 2010:

General taxes, which are principally comprised of property taxes, payroll taxes and regulatory fees, decreased $0.9 million, or 12 percent, in the three months ended June 30, 2011 over the same period in 2010, reflecting the ongoing impact of the recent property tax appeal and some timing differences on regulatory fees payable.

Table of Contents

Six months ended June 30, 2011 compared to June 30, 2010:

General taxes increased $4 million in the first six months of 2011 compared to 2010. The major factor that contributed to the change in general taxes was a the $5.2 million refund of property taxes in 2010 pursuant to a favorable ruling from the Oregon Supreme Court. For several years, we had been involved in litigation with the Oregon Department of Revenue over the taxability of certain inventories that were held for sale, including gas inventories. In January 2010, the Oregon Supreme Court unanimously ruled in our favor, stating that these inventories were exempt from property tax. As a result of this ruling, we were refunded $5.2 million, plus accrued interest, for taxes paid on inventories beginning with the 2002-03 tax year. We recognized a net $6.1 million increase in pre-tax income in the first quarter of 2010, which consisted of $5.2 million for the refund of property taxes, $1.9 million for accrued interest income, and $1.0 million of increased operations and maintenance expense for legal and consulting fees.

Depreciation and Amortization

Depreciation and amortization expense increased by $1.5 million, or 9 percent for the three months ended June 30, 2011, compared to the same period in 2010. For the six months ended June 30, 2011, depreciation and amortization expense increased by $2.9 million, or 9 percent, as compared to the same period in 2010. The increased expense in 2011 was primarily related to depreciation on Gill Ranch assets, which went into service in the fourth quarter of 2010. A portion of the increase was also related to additional investments in utility plant related to customer growth and system improvements.

Other Income and Expense – Net

The following table provides details on other income and expense – net by primary components:

	Three Months Ended June 30,		Six Months Ended June 30,	
Thousands	2011	2010	2011	2010
Gains from company-owned life insurance	$694	$645	$1,199	$1,041
Interest income	23	88	30	1,998
Income from equity investments	(353)	412	(353)	728
Net interest on deferred regulatory accounts	1,501	1,206	3,015	2,197
Gain (loss) on sale of investments	-	-	(96)	223
Other non-operating	(743)	(738)	(1,459)	(1,551)
Total other income and expense - net	$1,122	$1,613	$2,336	$4,636

Other income and expense – net for the six months ended June 30, 2011 decreased $2.3 million, from 2010 primarily due to the prior year's refund of property taxes as discussed above, which included $1.9 million in accrued interest income. Other income and expense also included a $0.8 million increase in interest from regulatory account balances largely due to smaller gas costs refund balances, which was partially offset by our share of reduced income from an equity investment.

Interest Expense – Net

Interest expense – net decreased $0.4 million and for the three and six months ended June 30, 2011 compared to the same periods in 2010. The decrease was primarily due to a $1.2 million savings from interest expense on long-term debt as a result of bonds that matured in 2010, partially offset by a $0.5 million increase for gas storage related to the Gill Ranch base gas agreement.

38

Table of Contents

Income Tax Expense

The decrease in income tax expense of $5.2 million or 15 percent for the six months ended June 30, 2011, compared to the same period in 2010, was primarily due to lower pre-tax consolidated earnings of $12.7 million or 15 percent and a decrease in our effective tax rate of 40.4 percent in 2011 compared to 40.5 percent in 2010.

For the 2011 tax year, the lower effective tax rate was primarily the result of a decrease in the Oregon statutory income tax rate from 7.9 percent for tax year 2010 to 7.6 percent for tax year 2011. For the 2010 tax year, the higher effective tax rate was primarily the result of increased amortization of our regulatory tax account on pre-1981 utility plant assets (see "Regulatory Matters—Rate Mechanisms," above) and a lower non-taxable gain on company-owned life insurance. For more information on our income taxes, including a reconciliation between the statutory federal and state income tax rates and the effective rate, see Note 10.

Financial Condition

Capital Structure

One of our long-term goals is to maintain a strong consolidated capital structure, generally consisting of 45 to 50 percent common stock equity and 50 to 55 percent long-term and short-term debt. If additional capital is required, then debt or equity securities are issued depending upon both the target capital structure and market conditions. These sources of capital are also used to fund long-term debt redemptions and short-term commercial paper maturities (see "Liquidity and Capital Resources," below, and Note 7). Achieving the target capital structure and maintaining sufficient liquidity to meet operating requirements are necessary to maintain attractive credit ratings and have access to capital markets at reasonable costs. Our consolidated capital structure at June 30, 2011 and 2010 and at December 31, 2010 was as follows:

	June 30,				December 31,	
	2011		2010		2010	
Common stock equity	47.9	%	48.2	%	44.7	%
Long-term debt	37.0	%	41.2	%	38.1	%
Short-term debt, including current maturities of long-term debt	15.1	%	10.6	%	17.2	%
Total	100	%	100	%	100	%

Liquidity and Capital Resources

At June 30, 2011, we had $3.7 million of cash and cash equivalents compared to $7.1 million at June 30, 2010. We also had $0.9 million in restricted cash invested at Gill Ranch as of June 30, 2011 and 2010, which was being held as collateral for equipment purchase contracts and construction loans. In order to maintain sufficient liquidity during periods of volatile capital markets, at times we will maintain higher cash balances, add short-term borrowing capacity, and pre-fund utility capital expenditures while long-term fixed rate environments are attractive. Our short-term liquidity is supported by cash balances, internal cash flow from operations, proceeds from the sale of commercial paper notes, committed multi-year credit facilities, cash available from surrender value in company-owned life insurance policies, and proceeds from the sale of long-term debt. We use long-term debt proceeds generally to finance utility capital expenditures, refinance maturing short-term and long-term debt and provide for general corporate purposes.

With our current debt ratings (see "Credit Ratings," below), we have been able to issue commercial paper and medium term notes (MTNs) at attractive rates and have not needed to borrow from our back-up credit facilities. In the event that we were not able to issue new debt due to market conditions, we expect that our near term liquidity needs could be met by using cash balances or drawing upon our committed credit facilities. We also have a universal shelf registration filed with the Securities and Exchange Commission for the issuance of secured and unsecured debt or equity securities, subject to market conditions and regulatory approvals. We have OPUC approval to issue up to $175 million of additional MTNs under the existing shelf registration, which was filed in January 2011.

Table of Contents

In the event that our senior unsecured long-term debt credit ratings are downgraded, or our outstanding derivative position exceeds a certain credit threshold, our counterparties under derivative contracts could require us to post cash, a letter of credit or other form of collateral, which could expose us to additional cash requirements and may trigger significant increases in short-term borrowings. If the credit risk-related contingent features underlying these contracts were triggered on June 30, 2011, we could have been required to post $16.9 million of collateral to our counterparties, but that assumes our long-term debt ratings were at non-investment grade levels, which is several rating levels below our current ratings (see "Credit Ratings," below).

Business developments that could have a material impact on our liquidity and capital resource position include pension contributions, income tax benefits and environmental expenditures and insurance recoveries. With respect to pension requirements, we expect to make additional contributions in 2011 and future years until we are fully funded under the Pension Protection Act rules (see "Pension Cost and Funding Status of Qualified Retirement Plans," below). With respect to federal income tax liabilities, an extension was granted that allows us to take 100 percent bonus depreciation on qualified expenditures during 2011, which significantly reduces our tax liability for the 2011 tax year, thereby providing cash flow benefits in 2011 and possibly 2012 (see "Cash Flows—Operating Activities," below). With respect to environmental liabilities, we expect to continue using cash resources to fund our environmental liabilities, but we also anticipate recovering amounts through insurance coverage or utility rates over the next several years, although the amount and timing of these expenditures and recoveries is uncertain (see Note 14).

In addition, Gill Ranch just recently began commercial operations in the fourth quarter of 2010. We anticipate future operating cash flows at Gill Ranch to increase over time as the facility grows to its full design capacity by the end of 2013 and as we contract for incremental storage capacity. The amount and timing of cash flows will depend on future storage values and our ability to optimize storage capacity.

In July 2010, the U.S. Congress passed and President Obama signed into law the "Wall Street Reform and Consumer Protection Act," requiring additional government regulation of derivative and over-the-counter transactions and expanded collateral requirements. While we are currently evaluating the new legislation to determine its impact on us from our derivative activities, if any, on our hedging procedures, results of operations, financial position and liquidity, we do not expect to know the full impact of the legislation until final regulations implementing the legislation are issued.

Based on several factors, including our current credit ratings, our experience issuing commercial paper, our current cash reserves, our committed credit facilities and other liquidity resources, and our expected ability to issue long-term debt under our universal shelf registration, we believe our liquidity is sufficient to meet anticipated near-term cash requirements, including all contractual obligations and investing and financing activities discussed below.

Off-Balance Sheet Arrangements

Except for certain lease and purchase commitments (see "Contractual Obligations," below), we have no material off-balance sheet financing arrangements.

Contractual Obligations

At June 30, 2011, our purchase commitments increased approximately $29 million since December 31, 2010, primarily involving contracts entered into in the normal course of business. In addition to these purchase commitments, we have entered into an agreement with Encana Oil & Gas (USA) Inc. to develop gas reserves for our utility, for which we expect to spend an additional $239 million over the next five years, subject to certain NW Natural rights to terminate the agreement. See "Financial Condition—Contractual Obligations," in the 2010 Form 10-K.

Table of Contents

Short-Term Debt

Our primary source of utility short-term liquidity is from internal cash flows and the sale of commercial paper. In addition to issuing commercial paper to meet working capital requirements, including seasonal requirements to finance gas inventories and accounts receivable, short-term debt may also be used to temporarily fund utility capital requirements. Commercial paper is periodically refinanced through the sale of long-term debt or equity securities. Our outstanding commercial paper, which is sold through two commercial banks under an issuing and paying agency agreement, is supported by one or more unsecured revolving credit facilities (see "Credit Agreements," below). Our commercial paper program did not experience any liquidity disruptions as a result of the credit problems that affected issuers of asset-backed commercial paper and certain other commercial paper programs over the last several years. At June 30, 2011 and 2010, our utility had commercial paper outstanding of $185.4 million and $106.9 million, respectively. The effective interest rate on the utility's commercial paper outstanding at June 30, 2011 and 2010 was 0.3 percent and 0.4 percent, respectively.

In March 2009, Gill Ranch entered into a cash collateralized credit facility for up to $40 million, which was extended through September 30, 2010. In June 2010, Gill Ranch repaid its $40 million bank loan. The effective interest rate on the Gill Ranch credit facility was 0.8 percent during 2010.

Credit Agreements

We have a syndicated multi-year credit agreement for unsecured revolving loans totaling $250 million, which may be extended for additional one-year periods subject to lender approval. All lenders agreed to extend the original term for an additional one-year period through May 31, 2013. We also had three bilateral credit agreements totaling $50 million in effect from November 30, 2010 through March 31, 2011. All lenders under our syndicated agreement are major financial institutions with committed balances and investment grade credit ratings as of June 30, 2011 as follows:

Lender rating, by category	Loan Commitment Amounts in Thousands Syndicated Facility
AA/Aa	$ 230,000
A/A	20,000
BBB/Baa	
Total	$ 250,000

Based on credit market conditions, it is possible that one or more lending commitments could be unavailable to us if the lender defaulted due to lack of funds or insolvency. However, based on our current assessment of our lenders' creditworthiness, including a review of capital ratios, credit default swap spreads and credit ratings, we believe the risk of lender default is minimal.

As discussed above, we extended commitments with all of our lenders under the syndicated agreement, with commitments totaling $250 million. The syndicated agreement also allows us to request increases in the total commitment amount from time to time, up to a maximum amount of $400 million, and to replace any lenders who decline to extend the maturity date of the credit agreement. The syndicated agreement also permits the issuance of letters of credit in an aggregate amount up to the applicable total borrowing commitment.

Any principal and unpaid interest amounts owed on borrowings under the credit agreements are due and payable on or before the maturity date. There were no outstanding balances under these credit agreements at June 30, 2011 and 2010. These agreements also require us to maintain a consolidated indebtedness to total capitalization ratio of 70 percent or less. Failure to comply with this covenant would entitle the lenders to terminate their lending commitments and accelerate the maturity of all amounts outstanding. We were in compliance with this covenant at June 30, 2011 and 2010, with consolidated indebtedness to total capitalization ratios of 52 percent and 54 percent, respectively.

Table of Contents

The syndicated agreement also require that we maintain credit ratings with Standard & Poor’s (S&P) and Moody’s Investors Service (Moody’s) and notify the lenders of any change in our senior unsecured debt ratings by such rating agencies. A change in our debt ratings by S&P or by Moody’s is not an event of default, nor is the maintenance of a specific minimum level of debt rating a condition of drawing upon the credit agreement. However, a change in our debt rating below BBB- or Baa3 would require additional approval from the OPUC prior to issuance of debt, and interest rates on any loans outstanding under the credit agreements are tied to debt ratings, which would increase or decrease the cost of any loans under the credit agreements when ratings are changed (see “Credit Ratings,” below).

Credit Ratings

Our debt credit ratings are a factor in our liquidity, affecting our access to the capital markets including the commercial paper market. Our debt credit ratings also have an impact on the cost of funds and the need to post collateral under derivative contracts. A change in our ratings below BBB- by S&P or Baa3 by Moody’s would require additional approval from the OPUC prior to our issuing additional long-term debt.

The following table summarizes our current debt ratings from S&P and Moody’s:

	S&P	Moody’s
Commercial paper (short-term debt)	A-1	P-1
Senior secured (long-term debt)	A+	A1
Senior unsecured (long-term debt)	n/a	A3
Corporate credit rating	A+	n/a
Ratings outlook	Stable	Stable

The above credit ratings are dependent upon a number of factors, both qualitative and quantitative, and are subject to change at any time. The disclosure of these credit ratings is not a recommendation to buy, sell or hold NW Natural securities. Each rating should be evaluated independently of any other rating.

Maturity and Redemption of Long-Term Debt

For the six months ended June 30, 2011, $10 million of secured MTNs with a coupon rate of 6.665% were redeemed at maturity. Over the next twelve months, $40 million of secured MTNs with a coupon rate of 7.13% will mature in March 2012. For additional long-term debt maturing over the next five years, see Part II, Item 7., "Results of Operations—Financial Condition—Contractual Obligations," in our 2010 Form 10-K.

Table of Contents

Cash Flows

Operating Activities

Six months ended June 30, 2011 compared to June 30, 2010:

Year-over-year changes in our operating cash flows are primarily affected by net income, changes in working capital requirements, and other cash and non-cash adjustments to operating results. For the six months ended June 30, 2011, cash flow from operating activities totaled $168.7 million, compared to $104.3 million in 2010. The significant factors contributing to changes in operating cash flow in the first six months of 2011 compared to 2010 are as follows:

- a decrease of $9.2 million from changes in receivables primarily due to higher balances from colder weather at the end of 2009, which benefitted cash flows during 2010;
- an increase of $21 million from changes in the deferred gas cost regulatory account balance, which reflects a lower variance between actual gas prices and embedded gas prices in the PGA for 2011 compared to 2010;
- an increase of $11.5 million from deferred income taxes, primarily reflecting higher tax benefits from bonus depreciation;
- an increase of $19 million from income taxes receivable and accrued taxes, primarily related to our federal tax refund of $14.4 million received in the first quarter of 2011; and
  - an increase of $9.3 million from changes in gas costs payable due to weather impact on gas purchases.

In September 2010, Congress passed the "Unemployment Insurance, Reauthorization and Job Creation Act of 2010" (the Act) and the legislation was signed into law by President Obama. The Act extended for one additional year the temporary bonus depreciation rules first enacted in the Economic Stimulus Act of 2008 and subsequently renewed in the American Recovery and Reinvestment Act of 2009. Under the bonus depreciation provision, an additional first-year tax deduction was allowed for depreciation equal to 50 percent of the adjusted basis of qualified property through September 8, 2010, and 100 percent through December 31, 2011, in the year the property is placed in service, and the remaining percentage recovered under the normal depreciation rules. The 50 percent or 100 percent depreciation deduction in the first year is an acceleration of depreciation deductions that otherwise would be taken in the later years of an asset's recovery period. As a result of this extension, we will recognize an increase in our cash flow by reducing our current tax liabilities for the 2011 tax year. Any deductions in excess of 2011 income tax liabilities for federal income tax purposes will be carried forward to the 2012 tax year. As of June 30, 2011, we have a federal and state income tax receivable balance of $26.3 million, which we expect to realize in cash flows during 2011. We received a federal refund of approximately $14.4 million during the first quarter of 2011.

For the year ended December 31, 2010, we reported an NOL carry-forward of approximately $20.2 million will be carried forward to reduce current taxes paid in the 2011 tax year. We anticipate that we will be able to use all the loss carry-forward in the current or future years.

Investing Activities

Six months ended June 30, 2011 compared to June 30, 2010:

Cash used in investing activities for the six months ended June 30, 2011 totaled $63.9 million, down from $90.4 million for the same period in 2010. Capital expenditures were $47.8 million in the six months ended June 30, 2011, down from $126 million for the same period in 2010, of which $83 million of the decrease was due to non-utility construction activity primarily related to Gill Ranch. We also invested $16.2 million into utility gas reserves in the second quarter of 2011 under our agreement with Encana.

Over the next five-year period, 2011 through 2015, total utility capital expenditures are estimated at between $400 and $500 million, and the investment in gas reserves are estimated at approximately $250 million, subject to certain NW Natural rights to terminate the agreement. The estimated level of utility capital expenditures over the next five years reflects assumptions for customer growth, storage facility improvements, technology investments and utility distribution improvements, including requirements under the current Pipeline Safety programs. Most of the required funds are expected to be internally generated over the five-year period, except for the funding of long-term gas reserves. The funding of our long-term gas reserves and any remaining funding that is needed to meet capital requirements will be obtained through the issuance of long-term debt or equity securities, with short-term debt providing liquidity and bridge financing.

Table of Contents

In 2011, we expect to spend less than $15 million on non-utility development projects, including Gill Ranch and Palomar. Gill Ranch capital expenditures are paid through equity funds and working capital. Palomar expects to continue working on revised plans for the east pipeline segment and to conduct an open season to determine regional needs. The initial planning and permitting costs have been financed with equity funds from us and our partner, TransCanada American Investments Ltd. For more information on non-utility investment opportunities, see Note 12 and "Strategic Opportunities—Gas Storage Operations" and "—Pipeline Diversification," above.

Financing Activities

Six months ended June 30, 2011 compared to June 30, 2010:

Cash used in financing activities during the six months ended June 30, 2011 totaled $104.6 million, up from cash used of $15.2 million for the same period in 2010. The main driver of this increase in financing activity is our short-term debt balances which decreased $72.0 million in the six months ended June 30, 2011, compared to a increase of $4.9 million for the same period in 2010. We continue to use long-term debt proceeds to finance capital expenditures, refinance maturing short-term or long-term debt maturities, and for general corporate purposes.

Pension Cost and Funding Status of Qualified Retirement Plans

We make pension contributions to company-sponsored qualified defined benefit plans based on actuarial assumptions and estimates, tax regulations and funding requirements under federal law. Our qualified defined benefit plans were underfunded by $95.4 million at December 31, 2010. For the six months ended June 30, 2011, we made cash contributions totaling $16.4 million into these qualified pension plans. We anticipate making additional contributions of between $5 million and $7 million before year end, for a total amount between $21 million and $23 million in 2011. In 2010 and 2009, we contributed a total of $10 million and $25 million, respectively, into these qualified pension plans. For more information on the funded status of our qualified retirement plans and other postretirement benefits, see Note 9, and Part II, Item 7., "Financial Condition—Pension Cost and Funding Status of Qualified Retirement Plans," and Part II, Item 8., Note 9, "Pension and Other Postretirement Benefits," in the 2010 Form 10-K.

We also contribute to a multi-employer union pension plan (Western States Plan) pursuant to our collective bargaining agreement. We made contributions totaling $0.2 million to the Western States Plan in both the six months ended June 30, 2011 and 2010, and we expect to contribute a total of $0.4 million during 2011. See Note 9 for further discussion.

Ratios of Earnings to Fixed Charges

For the six and twelve months ended June 30, 2011 and the twelve months ended December 31, 2010, our ratios of earnings to fixed charges, computed using the Securities and Exchange Commission method, were 4.38, 3.49 and 3.73 respectively. For this purpose, earnings consist of net income before taxes plus fixed charges, and fixed charges consist of interest on all indebtedness, the amortization of debt expense and discount or premium and the estimated interest portion of rentals charged to income. See Exhibit 12.

Table of Contents

Contingent Liabilities

Loss contingencies are recorded as liabilities when it is probable that a liability has been incurred and the amount of the loss is reasonably estimable in accordance with accounting standards for contingencies (see Part II, Item 7., “Application of Critical Accounting Policies and Estimates,” in our 2010 Form 10-K). At June 30, 2011, we had a regulatory asset of $120.3 million for deferred environmental costs, which includes $59.6 million for additional costs expected to be paid in the future and accrued interest of $16.7 million. If it is determined that both the insurance recovery and future customer rate recovery of such costs are not probable, then the costs will be charged to expense in the period such determination is made. For further discussion of contingent liabilities, see Note 14.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to various forms of market risk including commodity supply risk, commodity price and storage value risk, interest rate risk, foreign currency risk, credit risk and weather risk. We monitor and manage these financial exposures as an integral part of our overall risk management program. No material changes have occurred related to our disclosures about market risk for the six month period ending June 30, 2011. See Part I, Item 1A., “Risk Factors,” and Part II, Item 7A. “Quantitative and Qualitative Disclosures about Market Risk,” in the 2010 Form 10-K and Part II, Item 1A., “Risk Factors,” in this report for details regarding these risks.

ITEM 4. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

The Company's management, together with its consolidated subsidiaries, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, has completed an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the “Exchange Act”)). Based upon this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this report, our disclosure controls and procedures were effective to ensure that information required to be disclosed by us and included in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms and that such information is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

(b) Changes in Internal Control Over Financial Reporting

The Company's management, together with its consolidated subsidiaries, is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in the Exchange Act Rule 13a-15(f).

There have been no changes in our internal control over financial reporting that occurred during the quarter ended June 30, 2011 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. The statements contained in Exhibit 31.1 and Exhibit 31.2 should be considered in light of, and read together with, the information set forth in this Item 4(b).

Table of Contents

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Other than the proceedings disclosed in Note 14 and those proceedings disclosed and incorporated by reference in Part I, Item 3., "Legal Proceedings," in our 2010 Form 10-K, we have only routine nonmaterial litigation in the ordinary course of business.

ITEM 1A. RISK FACTORS

There were no material changes from the risk factors discussed in Part I, "Item 1A. Risk Factors," in our 2010 Form 10-K. In addition to the other information set forth in this report, you should carefully consider those risk factors, which could materially affect our business, financial condition or results of operations. The risks described in the 2010 Form 10-K are not the only risks facing our company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially affect our financial condition, results of operations or cash flows.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table provides information about purchases by us during the quarter ended June 30, 2011 of equity securities that are registered pursuant to Section 12 of the Exchange Act:

ISSUER PURCHASE OF EQUITY SECURITIES

Period	(a) Total Number of Shares Purchased(1)	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs(2)	(d) Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs(2)
Balance forward			2,124,528	$ 16,732,648
04/01/11 - 04/30/11	1,797	$45.01	-	-
05/01/11 - 05/31/11	23,444	45.53	-	-
06/01/11 - 06/30/11	2,892	44.13	-	-
Total	28,133	$45.35	2,124,528	$ 16,732,648

(1) During the quarter ended June 30, 2011, 24,760 shares of our common stock were purchased on the open market to meet the requirements of our Dividend Reinvestment and Direct Stock Purchase Plan. In addition, 3,373 shares of our common stock were purchased on the open market during the quarter to meet the requirements of our share-based programs. During the quarter ended June 30, 2011, no shares of our common stock were accepted as payment for stock option exercises pursuant to our Restated Stock Option Plan.

(2) We have a common stock share repurchase program under which we purchase shares on the open market or through privately negotiated transactions. We currently have Board authorization through May 31, 2012 to repurchase up to an aggregate of 2.8 million shares or up to an aggregate of $100 million. During the quarter ended June 30, 2011, no shares of our common stock were purchased pursuant to this program. Since the program's inception in 2000 we have repurchased approximately 2.1 million shares of common stock at a total cost of approximately $83.3 million.

ITEM 6. EXHIBITS

See Exhibit Index attached hereto.

Table of Contents

SIGNATURE

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

NORTHWEST NATURAL GAS COMPANY
(Registrant)

Dated: August 3, 2011

/s/ Stephen P. Feltz
Stephen P. Feltz
Principal Accounting Officer
Treasurer and Controller

Table of Contents

NORTHWEST NATURAL GAS COMPANY

EXHIBIT INDEX
To
Quarterly Report on Form 10-Q
For Fiscal Year Ended
June 30, 2011

Exhibit Number	Document
10.1	Carry and Earning Agreement by and between Encana Oil & Gas (USA) Inc. and Northwest Natural Gas Company, effective as of May 1, 2011, as amended by a First Amendment to C&E Agreement, dated March 22, 2011. Portions of this exhibit have been redacted and filed separately with the SEC pursuant to a confidential treatment request.
10.2	Service Agreement, dated February 16, 2011, between the Company and Gas Transmission Northwest Corporation.
10.3	Service Agreement, dated June 21, 2011, between the Company and Northwest Pipeline GP (Contract No. 100138).
10.4	Service Agreement, dated July 29, 2011, between the Company and Northwest Pipeline GP (Contract 139153).
10.5	Service Agreement, dated June 21, 2011, between the Company and Northwest Pipeline GP (Contract No. 100058).
10.6	Service Agreement, dated June 21, 2011, between the Company and Northwest Pipeline GP (Contract No. 138065).
10.7	Service Agreement, dated June 21, 2011, between the Company and Northwest Pipeline GP (Contract No. 100005).
10.8	Service Agreement, dated July 29, 2011, between the Company and Northwest Pipeline GP (Contract No. 139154).
12	Statement re computation of ratios of earnings to fixed charges.
31.1	Certification of Principal Executive Officer Pursuant to Rule 13a-14(a)/15-d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Principal Financial Officer Pursuant to Rule 13a-14(a)/15-d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Principal Executive Officer and Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Table of Contents

101 *The following materials from Northwest Natural Gas Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, formatted in Extensible Business Reporting Language (XBRL):
(i) Consolidated Statements of Income;
(ii) Consolidated Balance Sheets;
(iii) Consolidated Statements of Cash Flows; and
(iv) Related notes.

*Users of this data are advised pursuant to Rule 401 of Regulation S-T that the financial information contained in these XBRL documents is unaudited and that these are not the official publicly filed financial statements of Northwest Natural Gas Company. In accordance with Rule 402 of Regulation S-T, the information in these exhibits shall not be deemed to be “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, 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, or the Exchange Act, except as shall be expressly set forth by specific reference in such filing.