NORTHWEST NATURAL GAS CO
Form 10-Q
May 04, 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 March 31, 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	93-0256722
(State or other jurisdiction of incorporation or organization)	(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 [ ] Smaller reporting company [ ]
(Do not check if a 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 April 30, 2011, 26,672,812 shares of the registrant’s Common Stock (the only class of Common Stock) were outstanding.

NORTHWEST NATURAL GAS COMPANY

For the Quarterly Period Ended March 31, 2011

PART I. FINANCIAL INFORMATION

PART II. OTHER INFORMATION

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;
- procurement and development of new gas supplies;
- liquefied natural gas;
- estimated expenditures;
- 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 obligations under retirement plans;
- adequacy of, and shift in mix of, gas supplies;
- approval and adequacy of regulatory deferrals; and
- environmental, regulatory, litigation and insurance costs and recoveries.

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.

NORTHWEST NATURAL GAS COMPANY
PART I. FINANCIAL INFORMATION

Consolidated Statements of Income
(Unaudited)

Thousands, except per share amounts	Three Months Ended March 31, 2011	2010
Operating revenues:		
Gross operating revenues	$323,088	$286,529
Less: Cost of sales	180,625	148,561
Revenue taxes	7,955	7,042
Net operating revenues	134,508	130,926
Operating expenses:		
Operations and maintenance	31,172	30,666
General taxes	8,165	3,249
Depreciation and amortization	17,309	15,901
Total operating expenses	56,646	49,816
Income from operations	77,862	81,110
Other income and expense - net	1,214	3,023
Interest expense - net	10,449	10,489
Income before income taxes	68,627	73,644
Income tax expense	27,854	30,036
Net income	$40,773	$43,608
Average common shares outstanding:		
Basic	26,670	26,538
Diluted	26,724	26,601
Earnings per share of common stock:		
Basic	$1.53	$1.64
Diluted	$1.53	$1.64
Dividends declared per share of common stock	$0.435	$0.415

See Notes to Consolidated Financial Statements.

NORTHWEST NATURAL GAS COMPANY
PART I. FINANCIAL INFORMATION

Consolidated Balance Sheets
(Unaudited)

Thousands	March 31, 2011	March 31, 2010	December 31, 2010
Assets:			
Current assets:			
Cash and cash equivalents	$3,480	$8,839	$3,457
Restricted cash	924	40,924	924
Accounts receivable	94,521	78,347	67,969
Accrued unbilled revenue	42,342	39,244	64,803
Allowance for uncollectible accounts	(3,821)	(3,999)	(2,950)
Regulatory assets	48,195	55,872	52,714
Derivative instruments	4,861	450	2,245
Inventories:			
Gas	43,501	61,918	70,672
Materials and supplies	9,765	9,235	9,713
Income taxes receivable	23,645	-	41,066
Other current assets	13,292	15,481	19,652
Total current assets	280,705	306,311	330,265
Non-current assets:			
Property, plant and equipment	2,593,553	2,409,534	2,576,402
Less: Accumulated depreciation	733,639	702,307	722,239
Total property, plant and equipment - net	1,859,914	1,707,227	1,854,163
Regulatory assets	345,452	331,962	348,897
Derivative instruments	1,560	5	628
Other investments	69,501	67,558	69,094
Other non-current assets	14,421	15,970	13,569
Total non-current assets	2,290,848	2,122,722	2,286,351
Total assets	$2,571,553	$2,429,033	$2,616,616

See Notes to Consolidated Financial Statements.

NORTHWEST NATURAL GAS COMPANY
PART I. FINANCIAL INFORMATION

Consolidated Balance Sheets
(Unaudited)

Thousands	March 31, 2011	March 31, 2010	December 31, 2010
Capitalization and liabilities:			
Capitalization:			
Common stock - no par value; authorized 100,000 shares; issued and outstanding 26,673, 26,564 and 26,668 at March 31, 2011 and 2010, and December 31, 2010, respectively	$343,787	$338,012	$342,978
Retained earnings	385,899	361,310	356,727
Accumulated other comprehensive income (loss)	(6,458)	(5,870)	(6,604)
Total common stock equity	723,228	693,452	693,101
Long-term debt	551,700	601,700	591,700
Total capitalization	1,274,928	1,295,152	1,284,801
Current liabilities:			
Short-term debt	186,435	96,000	257,435
Current maturities of long-term debt	50,000	35,000	10,000
Accounts payable	71,839	93,534	93,243
Taxes accrued	10,063	27,325	10,579
Interest accrued	11,470	12,232	5,182
Regulatory liabilities	29,016	36,032	17,828
Derivative instruments	25,655	39,365	38,437
Other current liabilities	38,433	36,060	35,457
Total current liabilities	422,911	375,548	468,161
Deferred credits and other non-current liabilities:			
Deferred tax liabilities	396,357	311,691	373,409
Regulatory liabilities	263,876	247,517	258,031
Pension and other postretirement benefit liabilities	132,053	118,848	144,250
Derivative instruments	13,914	18,637	17,022
Other non-current liabilities	67,514	61,640	70,942
Total deferred credits and other non-current liabilities	873,714	758,333	863,654
Commitments and contingencies (see Note 14)	-	-	-
Total capitalization and liabilities	$2,571,553	$2,429,033	$2,616,616

See Notes to Consolidated Financial Statements.

NORTHWEST NATURAL GAS COMPANY
PART I. FINANCIAL INFORMATION

Consolidated Statement of Cash Flows
(Unaudited)

Thousands	Three Months Ended March 31, 2011	2010
Operating activities:		
Net income	$40,773	$43,608
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and amortization	17,309	15,901
Undistributed earnings from equity investments	25	(356)
Non-cash expenses related to qualified defined benefit pension plans	1,817	2,001
Contributions to qualified defined benefit pension plans	(13,645)	(10,000)
Deferred environmental expenditures	(1,759)	(3,632)
Other	(443)	(2,431)
Changes in assets and liabilities:		
Receivables	(3,122)	31,951
Inventories	27,119	9,804
Taxes accrued	16,905	6,288
Accounts payable	(14,406)	(24,882)
Interest accrued	6,288	6,797
Deferred gas costs	196	(15,428)
Deferred tax liabilities	25,048	11,517
Other - net	5,959	3,018
Cash provided by operating activities	108,064	74,156
Investing activities:		
Capital expenditures	(25,403)	(52,774)
Restricted cash	-	(5,381)
Other	(121)	782
Cash used in investing activities	(25,524)	(57,373)
Financing activities:		
Common stock issued (purchased) - net	(244)	566
Change in short-term debt	(71,000)	(6,000)
Cash dividend payments on common stock	(11,601)	(11,011)
Other	328	69
Cash used in financing activities	(82,517)	(16,376)
Increase in cash and cash equivalents	23	407
Cash and cash equivalents - beginning of period	3,457	8,432
Cash and cash equivalents - end of period	$3,480	$8,839
Supplemental disclosure of cash flow information:		
Interest paid	$4,162	$3,325
Income taxes paid	$-	$9,000

See Notes to Consolidated Financial Statements.

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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, including normal recurring accruals, that management considers necessary for a fair statement of the results for each period reported. 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 three months ended March 31, 2011, except for a change in the application of our accounting policy with respect to revenue recognition for the regulatory adjustment for income taxes paid. For further discussion of significant accounting policies, see Note 2 below. Subsequent events are reported in Note 15.

Certain prior year balances in our consolidated financial statements have been combined or reclassified to conform with the current presentation. These changes had no impact on our prior year's consolidated results of operations and no material impact on financial condition or cash flows.

2. Summary of Significant Accounting Policies

Industry Regulation

At March 31, 2011 and 2010 and at December 31, 2010, the amounts deferred as regulatory assets and liabilities were as follows:

	Regulatory Assets		
Thousands	March 31, 2011	March 31, 2010	December 31, 2010
Current:			
Unrealized loss on derivatives(1)	$25,655	$39,365	$38,437
Pension and other postretirement benefit liabilities(2)	10,988	7,502	10,988
Other(3)	11,552	9,005	3,289
Total current	$48,195	$55,872	$52,714
Non-current:			
Unrealized loss on derivatives(1)	$13,914	$18,637	$17,022
Income tax asset	70,241	75,515	72,341
Pension and other postretirement benefit liabilities(2)	115,490	108,010	118,248
Environmental costs(4)	117,544	107,537	114,311
Other(3)	28,263	22,263	26,975
Total non-current	$345,452	$331,962	$348,897

	Regulatory Liabilities		
Thousands	March 31, 2011	March 31, 2010	December 31, 2010
Current:			
Gas costs payable	$14,144	$26,164	$15,583
Unrealized gain on derivatives(1)	4,861	450	2,245
Other(3)	10,011	9,418	-
Total current	$29,016	$36,032	$17,828
Non-current:			
Gas costs payable	$3,932	$2,377	$2,297
Unrealized gain on derivatives(1)	1,560	5	628
Accrued asset removal costs	256,203	242,952	252,941
Other(3)	2,181	2,183	2,165
Total non-current	$263,876	$247,517	$258,031

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

(2) Certain pension and other postretirement benefit liabilities of the utility are approved for regulatory deferral. Such amounts are recoverable in rates, including an interest component, when recognized in pension expense or net periodic benefit cost (see Note 9).

(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. We earn the utility's authorized rate of return as a carrying charge on amounts paid, whereas the amounts accrued but not yet paid do not earn a rate of return or a carrying charge until expended.

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 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 are required to automatically implement a rate refund, or a rate surcharge, to utility customers on an annual basis. The refund or surcharge amount is based on the estimated difference between income taxes paid and income taxes authorized to be collected in customer rates. We have recorded the estimated refund, or surcharge, each quarter since 2007 based on the estimated annual amount to be recognized. However, on March 29, 2011, a legislative bill was introduced that would repeal SB 408 if enacted as drafted in its current form (SB 967 or Bill). As of May 4, 2011, the Oregon Senate had approved SB 967, but the Bill has not been approved by the Oregon House of Representatives or signed by the Governor of Oregon. We currently believe there is substantial uncertainty surrounding the continuation of the current legal requirements of SB 408. Accordingly, we determined that the threshold for recognizing revenues under the accounting standard for the effects of regulation had not been met, and therefore we did not record an estimated refund, or surcharge, in the first quarter of 2011 for this regulatory adjustment for income taxes paid.

New Accounting Standards

Adopted Standards

Fair Value Disclosures. In January 2010, the Financial Accounting Standards Board 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

There have been no recent accounting pronouncements issued, but not yet effective, which are expected to have a material impact on our financial condition, results of operations or cash flows.

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 March 31,	
Thousands, except per share amounts	2011	2010
Net income	$40,773	$43,608
Average common shares outstanding - basic	26,670	26,538
Additional shares for stock-based compensation plans	54	63
Average common shares outstanding - diluted	26,724	26,601
Earnings per share of common stock - basic	$1.53	$1.64

Earnings per share of common stock - diluted	$1.53	$1.64

For the three months ended March 31, 2011 and 2010, 2,150 and 5,120 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.

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.

The following table presents summary financial information about the reportable segments for the three months ended March 31, 2011, and 2010. Inter-segment transactions were insignificant.

	Three Months Ended March 31			
		Non-Utility		
Thousands	Utility	Gas Storage	Other	Total
2011				
Net operating revenues	$129,162	$5,304	$42	$134,508
Depreciation and amortization	15,914	1,395	-	17,309
Income from operations	76,124	1,716	22	77,862
Net income (loss)	40,130	688	(45)	40,773
Total assets at March 31, 2011	2,304,731	244,403	22,419	2,571,553
2010				
Net operating revenues	$125,473	$5,411	$42	$130,926
Depreciation and amortization	15,566	335	-	15,901
Income from operations	76,582	4,511	17	81,110
Net income	40,892	2,501	215	43,608
Total assets at March 31, 2010	2,190,849	217,266	20,918	2,429,033
Total assets at December 31, 2010	$2,310,388	$282,945	$23,283	$2,616,616

5. Common Stock

As of March 31, 2011, our common shares authorized were 100,000,000 and our outstanding shares were 26,672,812.

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 2011 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 three months ended March 31, 2011, but since inception in 2000 a total of 2.1 million shares have been repurchased at a total cost of $83.3 million.

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	

In February 2011, the Board approved a payout of performance-based stock awards under the LTIP for the 2008-10 award period. Shares of common stock were purchased on the open market to satisfy these awards.

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 with 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 March 31, 2011, there was $1.3 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 medium-term notes (MTNs) with maturity dates from 2011 through 2035, interest rates ranging from 3.95 percent to 9.05 percent, and a weighted-average coupon rate of 6.17 percent. For the three months ended March 31, 2011, we did not issue or redeem any MTNs. For more detail on our outstanding long-term debt, see Note 7 in our 2010 Form 10-K.

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 for other company's 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.

	March 31,		December 31,
Thousands	2011	2010	2010
Carrying amount	$601,700	$636,700	$601,700
Estimated fair value	$680,436	$687,937	$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 $6.5 million and $5.9 million as of March 31, 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 three months ended March 31, 2011 and 2010.

	Three Months Ended March 31,	
Thousands	2011	2010
Net income	$40,773	$43,608
Amortization of employee benefit plan liability, net of tax	146	98
Total comprehensive income	$40,919	$43,706

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 March 31,			
	Pension Benefits		Other Postretirement Benefits	
Thousands	2011	2010	2011	2010
Service cost	$1,899	$1,773	$168	$156
Interest cost	4,527	4,491	344	343
Expected return on plan assets	(4,456)	(4,564)	-	-
Amortization of net actuarial loss	2,692	1,768	68	7
Amortization of prior service costs	88	206	49	49
Amortization of transition obligations	-	-	103	103
Net periodic benefit cost	4,750	3,674	732	658
Amount allocated to construction	(1,235)	(953)	(226)	(208)
Net amount charged to expense	$3,515	$2,721	$506	$450

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

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 $0.1 million to the Western States Plan for both the three months ended March 31, 2011 and 2010. If we withdraw and the plan is underfunded, we could be assessed a withdrawal liability. Currently, we have no intent to withdraw from the plan, so we have not recorded a withdrawal liability.

Employer Pension Contributions

During the first quarter of 2011 we made cash contributions totaling $13.6 million to our qualified defined benefit pension plans. We also expect to contribute up to an additional $10 million to these qualified plans over the last nine 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 three months ended March 31, 2011 and 2010 varied from the combined federal and state statutory tax rates principally due to the following:

	March 31,			
	2011		2010	
Federal statutory tax rate	35.0	%	35.0	%
Increase (decrease):				
Current state income tax, net of federal tax benefit	4.6	%	4.9	%
Amortization of investment and energy tax credits	-0.4	%	-0.5	%
Differences required to be flowed-through by regulatory commissions	1.5	%	1.5	%
Gains on company and trust-owned life insurance	-0.2	%	-0.2	%
Other - net	0.1	%	0.1	%
Effective income tax rate	40.6	%	40.8	%

The decrease in our effective tax rate for the three months ended March 31, 2011 compared to the same period in 2010 was minor and primarily due to a change in state income tax rates. See Note 10 in our 2010 Form 10-K.

11. Property, Plant and Equipment

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

	March 31,		December 31,
Thousands	2011	2010	2010
Utility plant in service	$2,264,055	$2,206,571	$2,247,952
Utility construction work in progress	28,464	25,736	29,324
Less: Accumulated depreciation	720,134	691,420	710,214
Utility plant-net	1,572,385	1,540,887	1,567,062
Non-utility plant in service	292,089	66,084	290,038
Non-utility construction work in progress	8,945	111,143	9,088
Less: Accumulated depreciation	13,505	10,887	12,025
Non-utility plant-net	$287,529	$166,340	$287,101
Total property, plant and equipment	$1,859,914	$1,707,227	$1,854,163

12. Investments

Our other long-term 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.

Variable Interest Entities. 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 Gas Transmission Northwest Corporation (GTN), an indirect wholly-owned subsidiary of TransCanada Corporation. As of March 31, 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.

PGH Impairment Analysis. In March 2011, 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 intends to file an application later this year or in 2012 to reflect changes in the project and more closely align with the region's current and future gas needs. Palomar is working with customers in the Northwest to further understand their gas transportation needs. Assuming Palomar obtains commercial support for its revised pipeline proposal, Palomar expects to file a new certificate application with FERC.

We performed an impairment analysis of our equity investment as of March 31, 2011 and determined that we did not have any impairment because the fair value of expected cash flows from development of this pipeline project exceeds our equity investment. If, however, we learn 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 $14.4 million based on the amount of our equity investment of $14.8 million as of March 31, 2011 net of cash and working capital at Palomar. We will continue to monitor and update our impairment analysis as needed.

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 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. 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, including 62 percent financially hedged and 15 percent physically hedged with gas in storage.

At March 31, 2011, we were hedged with financial contracts for the upcoming 2011-12 gas year at approximately 50 percent based on anticipated sales volumes. Of the amount currently hedged for the 2011-12 gas year approximately 35 percent was hedged with financial contracts and an additional 15 percent attributable to storage from future purchases and current storage levels.

The following table discloses the income statement presentation for the unrealized gains and losses from our derivative instruments for the years ended March 31, 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			
	March 31, 2011		March 31, 2010	
Thousands	Natural gas commodity(1)	Foreign currency (2)	Natural gas commodity(1)	Foreign currency (2)
Cost of sales	$ (33,750)	$ -	$ (57,564)	$ -
Other comprehensive income (loss)	-	602	-	(17)
Less:				
Amounts deferred to regulatory accounts on balance sheet	33,750	(602)	57,564	17
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.

We had no collateral posted with our counterparties as of March 31, 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 $33.1 million at March 31, 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	$ -	$ -	$ -	$ 3,223	$ 18,058
Without Adequate Assurance Calls	$ -	$ -	$ -	$ 3,223	$ 14,897

In the three months ended March 31, 2011 and 2010, we realized net losses of $20.9 million and $6.2 million, respectively, from the settlement of natural gas hedge contracts at maturity, which were recorded as increases to the cost of gas. 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.

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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 March 31, 2011. As of March 31, 2011 and 2010 and December 31, 2010, the fair value was $33.1 million, $57.5 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 three months ended March 31, 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.

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 and an Ecological and Human Health Risk Assessment with the ODEQ, which outlined a range of remedial alternatives for the most contaminated portion of the Gasco site. In May 2007, we completed a revised Remediation Investigation Report and submitted it to the ODEQ for review. 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 March 31, 2011. The 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 other work, we have recorded an additional accrued liability of $38.0 million, which reflects the low end of the range of potential liability. We have accrued at the low end of the range of potential liability for the sediments project and other environmental work at the Gasco site 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 March 31, 2011 for the Siltronic site is $1 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.

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 March 31, 2011, we have a liability accrued of $8 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 March 31, 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 March 31, 2011, we have an estimated liability accrued of $0.9 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.

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

	Current Liabilities			Non-Current Liabilities		
Thousands	Mar. 31, 2011	Mar. 31, 2010	Dec. 31, 2010	Mar. 31, 2011	Mar. 31, 2010	Dec. 31, 2010
Gasco site	$13,718	$9,924	$11,366	$36,099	$42,165	$38,921
Siltronic site	730	679	720	291	508	201
Portland Harbor site	2,219	1,873	2,304	5,829	7,041	5,784
Central Service Center site	5	5	5	501	511	510
Front Street site	-	72	1	947	252	1,097
Other sites	-	-	-	117	106	108
Total	$16,672	$12,553	$14,396	$43,784	$50,583	$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 expect authorization during the second quarter of 2011. In addition, we filed a request with the Washington Utilities and Transportation Commission (WUTC) in February 2011 to defer certain environmental costs associated with services provided to Washington customers, and expect an order from the WUTC during the second quarter of 2011.

On a cumulative basis, we have recognized a total of $106.3 million for environmental costs, including legal, investigation, monitoring and remediation costs, including $4.9 million accrued and paid prior to regulatory deferral order approval. At March 31, 2011, we had a regulatory asset of $117.5 million, which includes $47.1 million of total paid expenditures to date, $60.5 million for additional environmental costs expected to be paid in the future and accrued interest of $15.3 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 ten 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 in excess of $40 million in losses it has incurred to date, as well as declaratory relief for additional losses it expects to incur in the future. After 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.

We anticipate that our regulatory recovery of environmental cost deferrals will not be initiated within the next 12 months because we do not expect to have concluded our insurance recovery efforts during that time period, and because recovery would be expected to occur through the implementation of new rates through a general rate proceeding. As such we have classified our regulatory assets for environmental cost deferrals as non-current. The following table summarizes the non-current regulatory assets relating to environmental sites at March 31, 2011 and 2010 and December 31, 2010:

	Non-Current Regulatory Assets		
Thousands	March 31, 2011	March 31, 2010	December 31, 2010
Gasco site	$76,338	$70,411	$74,205
Siltronic site	3,440	3,020	3,174
Portland Harbor site	34,732	32,140	33,940
Central Service Center site	558	550	553
Front Street site	2,042	1,032	2,020
Other sites	434	384	420
Total	$117,544	$107,537	$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.

15. Subsequent Event

On April 28, 2011 the OPUC issued an order approving our investment to develop gas reserves on behalf of our Oregon customers under an agreement with Encana Oil & Gas (USA) Inc. Under the agreement, we expect to invest approximately $45-55 million a year, over a five-year period, for a total investment of about $250 million, which will cover a portion of drilling costs in exchange for working interests in certain sections of the Jonah Field located north of Rock Springs, Wyoming. These sections include both future and current producing wells. The gas reserves will provide long-term gas supplies for our Oregon utility customers over a period expected to be about 30 years. During the first 10 years of the agreement, we forecast to receive approximately 58 billion cubic feet (Bcf) from the transaction, or 8-10 percent of our average annual requirements for utility operations. Our total investment under the agreement is expected to result in about 93 Bcf of gas at an average all-in price of approximately $5.15 per dekatherm. We estimate net present value savings to customers of over $50 million over the life of the investment as compared to other long-term supply alternatives.

Under the order, the OPUC determined that the investment was prudent and that the Company is allowed to recover its costs under the agreement on an ongoing basis through its Purchased Gas Adjustment (PGA) cost sharing mechanism, including the deferral process for the commodity cost of gas. Annually, the Company will forecast amounts related to the costs and volumes expected, and variances will be subject to the PGA's normal sharing mechanism up to $10 million of variance. Any variance in excess of $10 million, either negative or positive, will be passed through to customers at 100 percent, rather than at the 80 or 90 percent level associated with the normal sharing mechanism. As part of the decision by the OPUC to approve the Company's investment, we will file a general rate case in Oregon no later than December 31, 2011.

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 months ended March 31, 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). Together these accounts make up our regulated local gas distribution business, our 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 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).

Executive Summary

Highlights of the first quarter of 2011 as compared to the same period in 2010 include:

- Consolidated earnings of $40.8 million or $1.53 per share in the first quarter of 2011, as compared to $43.6 million and $1.64 in the first quarter of 2010;
- Net income from utility operations decreased $0.8 million, from $40.9 million in 2010 to $40.1 million in 2011, largely due to benefits received last year from a property tax refund and the regulatory adjustment for income taxes paid (see Revenue Recognition below under Application of Critical Accounting Policies and Estimates for further discussion of the regulatory adjustment for income taxes paid);
- Net income from gas storage operations decreased $1.8 million, from $2.5 million in 2010 to $0.7 million in 2011, primarily reflecting Gill Ranch’s initial start-up costs and lower level of contracted capacity prior to its first injection season beginning April 1, 2011;
- Consolidated net operating revenues (margin) increased $3.6 million or 3 percent over 2010, with utility margin up $3.7 million and gas storage margin down $0.1 million;
- Consolidated total operating expenses increased $6.8 million or 14 percent over 2010, but that was largely attributed to a $5.2 million refund of property tax expense at the utility in 2010 and start-up costs at Gill Ranch;
- Other income decreased $1.8 million in 2011 compared to 2010, primarily due to $1.9 million of interest income received by the utility in 2010 in connection with the property tax refund referred to above;
- Cash flow from operating activities in 2011 was $108.0 million, for an increase of $33.9 million or 46 percent over 2010; and
- The utility added more than 6,000 new customers over the last 12 months, for an annual growth rate of 0.9 percent compared to 0.7 percent a year ago.

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Issues, Challenges and Performance Measures

Economic Environment. Weakness in the local, national and global economies has continued to adversely impact utility customer growth, the demand for natural gas, and the value of natural gas storage services. Most recently, our utility's annual customer growth rate increased slightly to 0.9 percent at March 31, 2011, as compared to 0.7 percent at March 31, 2010. Although total delivered volumes to utility customers in the first quarter of 2011 increased 20 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. We entered the 2010-11 gas contract year, which began November 1, 2010, with gas commodity prices hedged at approximately 77 percent of our forecasted purchase volumes. In addition, we are currently hedged at approximately 50 percent for the 2011-12 gas contract year and between 5 and 10 percent for the 2012-13 gas contract year. 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, coupled with quality service and energy saving programs for customers, can help strengthen natural gas' competitive price advantage compared to other fuels. See discussion of Utility Investment in Gas Reserves below under Strategic Opportunities.

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 limiting Gill Ranch's ability to sign customer contracts for longer terms at favorable prices.

Environmental Costs. We accrue all 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. However, before we can seek recovery from customers, we are expected to pursue recovery from insurance policies. 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.

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 new natural gas infrastructure in the 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 ratings; 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. Gill Ranch began operations during the fourth quarter of 2010. Gill Ranch is 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. 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. For more information, see Note 4 in this report and Part II, Item 7., “2011 Outlook—Strategic Opportunities,” in our 2010 Form 10-K.

The Pacific Northwest storage 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 2011, we expect to continue planning for possible expansion at our gas storage facilities near Mist, Oregon 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 earliest 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 will 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 Gas Transmission Northwest Corporation (GTN), 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).

In March 2011, Palomar withdrew its original application with FERC for a natural gas pipeline in Oregon, but at the same time Palomar 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 eastern portion of the pipeline between Madras and Molalla in Oregon.

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 reserves 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 agreement, we forecast the volumes of gas received under the agreement to provide approximately 8 to 10 percent of the average annual requirements of our utility customers. Under the agreement, we expect to invest approximately $45 million to $55 million a year for five-years, with our total investment estimated to be about $250 million.

On April 28, 2011, the OPUC issued an order finding this gas reserve investment prudent and approving it for utility ratemaking, which provides for the recovery of the costs plus a rate base return on our investment through the annual Purchased Gas Adjustment (PGA) mechanism, including the deferral process for the commodity cost of gas. Annually, we will forecast the amounts related to costs and volumes expected, and variances between forecasted and actual will be subject to the PGA incentive sharing provision 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

The most significant factors contributing to the $2.8 million decrease in consolidated net income as compared to the prior year 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 $1.0 million decrease under operations and maintenance, plus an interest income decrease of $1.9 million under other income;
- a $2.7 million decrease related to a change in our revenue recognition policy for the regulatory adjustment of income taxes paid in 2011 as compared to 2010 (see "Application of Critical Accounting Policies and Estimates – Revenue Recognition," and "Results of Operations - Business Segments - Utility Operations - Regulatory Adjustment for Income Taxes Paid," below); and
- a $1.8 million decrease in net income from our gas storage segment, primarily reflecting Gill Ranch's low level of contracted capacity prior to its first injection season beginning April 1, 2011 coupled with initial start-up costs.

Partially offsetting the above factors were:

- a $6.4 million increase in utility net operating revenue (margin) attributable to an increase in residential and commercial customer use, which reflect gains from colder weather and customer growth, an increase in industrial use, and an increase in our incentive share of gas cost savings; and
- a $2.2 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 first quarter of 2011, compared to 41.5 cents per share in the first quarter of 2010. The Board of Directors declared a quarterly dividend on our common stock of 43.5 cents per share, payable on May 13, 2011, to shareholders of record on April 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.

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 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 are required to automatically implement a rate refund, or a rate surcharge, to utility customers on an annual basis. The refund or surcharge amount is based on the estimated difference between income taxes paid and income taxes authorized to be collected in customer rates. We have recorded the estimated refund, or surcharge, each quarter since 2007 based on the estimated annual amount to be recognized. However, on March 29, 2011, a legislative bill was introduced that would repeal SB 408 if enacted as drafted in its current form (SB 967 or Bill). As of May 4, 2011, the Oregon Senate had approved SB 967, but the Bill has not been approved by the Oregon House of Representatives or signed by the Governor of Oregon. We currently believe there is substantial uncertainty surrounding the continuation of the current legal requirements of SB 408. Accordingly, we determined that the threshold for recognizing revenues under the accounting standard for the effects of regulation had not been met, and therefore we did not record an estimated refund, or surcharge, in the first quarter of 2011 for this regulatory adjustment for income taxes paid. See “Results of Operations—Business Segments - Utility Operations—Regulatory Adjustment for Income Taxes Paid,” below for a further discussion of regulatory asset amounts included on the balance sheet as of March 31, 2011 related to the prior year.

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 by the OPUC), Washington Utilities and Transportation Commission (WUTC), FERC, and with respect to Gill Ranch, the CPUC. The OPUC and WUTC and, with respect to Gill Ranch, the 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 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, operating and maintenance costs and investments 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, 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.

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 is 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 by August 1 of 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 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. In 2010 and 2009, the ROE threshold after adjustment for long-term interest rates was 11.02 percent and 11.5 percent, respectively. No amounts were required to be refunded to customers as a result of the 2009 utility earnings review. Based upon utility results for 2010 and the first quarter of 2011 we accrued approximately $0.5 million and $1.0 million, respectively, for refund to customers in future rates

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. We do not have an earnings or gas cost sharing mechanism in Washington.

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 second quarter of 2011. See Note 14. In February 2011, we filed a request with the WUTC to defer environmental costs associated with services provided to Washington customers. We expect an order from the WUTC within the following few months.

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, and $1.3 million was deferred in the first quarter of 2011. Future years' deferrals will depend on changes in plan assets and projected benefit liabilities using a number of key assumptions, 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.

Our utility segment in the first quarter of 2011 earned $40.1 million, or $1.50 per share, compared to $40.9 million, or $1.54 per share for the same period in 2010. The major factors contributing to the change in earnings were higher margins from residential and commercial customers, which were up $6.2 million largely due to the impact of colder weather, along with higher industrial customer margins, which were up $0.5 million, partially offset by increased operating expenses. Total volumes sold and delivered in the first quarter of 2011 increased 20 percent over last year, with residential and commercial volumes up 29 percent on weather that was 21 percent colder than last year, plus a 5 percent increase in industrial volumes over last year. Operating expenses were higher in the first quarter of 2011 primarily due to a refund of property taxes recognized in the first quarter of 2010 (see General Taxes, below).

Our weather normalization mechanism adjusted residential and commercial margins down by $5.9 million for the first quarter of 2011 based on temperatures that were 6 percent colder than average, compared to a margin increase of $13.5 million for the first quarter of 2010 when temperatures were 13 percent warmer than average. Our decoupling mechanism adjusted residential and commercial margins up by $8.7 million in 2011, compared to a margin increase of $7.9 million in 2010.

The following table summarizes the composition of gas utility volumes, revenues and margin:

Thousands, except degree day and customer data	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010	Favorable/ (Unfavorable) 2011 vs. 2010
Utility volumes - therms:			
Residential sales	174,930	133,860	41,070
Commercial sales	99,967	78,856	21,111
Industrial - firm sales	10,637	10,153	484
Industrial - firm transportation	35,690	32,611	3,079
Industrial - interruptible sales	17,239	16,324	915
Industrial - interruptible transportation	62,951	61,599	1,352
Total utility volumes sold and delivered	401,414	333,403	68,011
Utility operating revenues - dollars:			
Residential sales	$ 198,774	$ 169,609	$ 29,165
Commercial sales	95,313	80,075	15,238
Industrial - firm sales	8,956	8,618	338
Industrial - firm transportation	1,591	1,436	155
Industrial - interruptible sales	10,483	10,381	102
Industrial - interruptible transportation	2,310	1,919	391
Regulatory adjustment for income taxes paid(1)	286	2,984	(2,698)
Other revenues	14	6,041	(6,027)
Total utility operating revenues	317,727	281,063	36,664
Cost of gas sold	180,610	148,548	(32,062)
Revenue taxes	7,955	7,042	(913)
Utility margin	$ 129,162	$ 125,473	$ 3,689
Utility margin:(2)			
Residential sales	$ 84,252	$ 66,404	$ 17,848
Commercial sales	32,558	25,708	6,850
Industrial - sales and transportation	7,610	7,123	487
Miscellaneous revenues	1,584	1,673	(89)
Gain (loss) from gas cost incentive sharing	1,035	199	836
Other margin adjustments	(1,027)	(19)	(1,008)
Margin before regulatory adjustments	126,012	101,088	24,924
Weather normalization adjustment	(5,861)	13,535	(19,396)
Decoupling adjustment	8,725	7,866	859
Regulatory adjustment for income taxes paid(1)	286	2,984	(2,698)
Utility margin	$ 129,162	$ 125,473	$ 3,689
Customers - end of period:			
Residential customers	612,738	606,935	5,803
Commercial customers	62,800	62,477	323
Industrial customers	908	917	(9)
Total number of customers - end of period	676,446	670,329	6,117
Actual degree days	1,974	1,627	
Percent colder (warmer) than average weather(3)	6 %	(13) %	

(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.

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.

The primary changes that impacted margin from residential and commercial sales for the three months ended March 31, 2011 compared to March 31, 2010 were as follows:

- utility sales volumes were 29 percent higher, primarily reflecting 21 percent colder weather;
- utility operating revenues increased $44.4 million or 18 percent primarily due to 29 percent increased volumes, partially offset by lower average use per customer due to conservation efforts; and
- utility margin increased $6.2 million or 5 percent reflecting increased volumes from residential and commercial customer growth of 0.9 percent 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. The primary changes that impacted volumes and margins from industrial sales and transportation services for the three months ended March 31, 2011 compared to March 31, 2010 were as follows:

- volumes delivered to industrial customers increased 5.8 million therms, or 5 percent, due to a slight increase in energy demand. The majority of the increased volumes were attributable to the manufacturing sector; and
- margin from industrial customers increased $0.5 million, or 7 percent primarily due to the increase in total volumes delivered.

Regulatory Adjustment for Income Taxes Paid

Oregon law currently requires 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 pay less in income taxes related to utility operations than we collect from Oregon utility customers, then we are required to refund the excess to our Oregon utility customers. Conversely, if we pay more in income taxes than we collect from Oregon utility customers, then we are required to collect a surcharge from Oregon utility customers.

For the 2009 tax year, the OPUC approved our tax filing to recover $5.6 million, including interest, through a surcharge to Oregon utility customers. It was agreed that the 2009 surcharge, plus accrued interest, would be collected over a one-year period beginning June 1, 2011. For the 2010 tax year, we estimated the difference between income taxes paid and the amounts collected in rates will result in a surcharge of $7.1 million, excluding interest. The 2010 surcharge was primarily driven by a refund of property taxes as well as by utility operating margins including gains from gas cost savings related to our PGA incentive sharing.

For the three months ended March 31, 2011, we estimate the surcharge to be $2.7 million for the regulatory adjustment of income taxes paid. However, we did not recognize revenues in this period for the regulatory adjustment due to the uncertainty surrounding our ability to collect the expected 2011 surcharge in future rates. For further discussion, see “Revenue Recognition” above under Application of Critical Accounting Policies and Estimates. However, we did recognize revenues of $0.3 million in the three months ended March 31, 2011 for accrued interest attributed to surcharges related to the 2009 and 2010 tax years, as compared to $3.0 million for the same period in 2010, which included a surcharge of $2.9 million plus accrued interest of $0.1 million attributed to the 2008 and 2009 tax years.

On March 29, 2011, legislation was introduced in Oregon (SB 967) to repeal existing statutes governing the annual regulatory adjustment for income taxes paid. This legislative bill would repeal the regulatory adjustment for tax years after 2009 upon the effective date. In order to ensure a proper balance between income taxes collected in rates by regulated natural gas and electric utilities and amounts actually paid to taxing authorities, SB 967 would require the OPUC to make decisions in future ratemaking proceedings on the amounts of income taxes to be recovered in rates. As of May 4, 2011, SB 967 had been approved by the Oregon Senate but not by the Oregon House of Representatives. If the Oregon legislature votes to pass SB 967 in its current form and the bill is signed into law by the governor, then the asset amounts on the balance sheet at March 31, 2011 for the 2010 tax year, which totals $7.4 million including accrued interest would be impaired and need to be written-off. Such an impairment would result in an after-tax adjustment of approximately $4.4 million, which is equivalent to 17 cents per share.

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 cost of gas sold. Other revenues decreased from $6.0 million for the three months ended March 31, 2010 to less than $0.1 million for the three months ended March 31, 2011, primarily reflecting a $2.1 million decrease in the decoupling amortization, a $1.0 million accrual for estimated refunds to utility customers related to our earnings sharing mechanism, a $1.4 million decrease for the warm deferral related to colder weather, and a $1.3 million decrease in other regulatory amortizations.

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 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). The following summarizes the major factors that contributed to changes in cost of gas sold for the three months ended March 31, 2011:

- total cost of gas sold increased $32.1 million, or 22 percent, due to a 20 percent increase in total sales volumes and a 2 percent decrease in the average cost of gas sold per therm;
- the average gas cost collected through rates decreased from 61 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 $20.9 million were realized and included in cost of gas sold for the three months ended March 31, 2011, compared to $6.2 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 $1.0 million in the first quarter of 2011 compared to $0.2 million in 2010. For a discussion of our gas cost incentive sharing mechanism, see "Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment," above.

Business Segments - Gas Storage

Our gas storage segment primarily consists of the acquisition, development, operation and management of natural gas storage facilities. As of March 31, 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. For the three months ended March 31, 2011, our gas storage segment earned $0.7 million, or 3 cents per share, compared to $2.5 million, or 9 cents per share, for the same period in 2010. This decrease was primarily related to net losses at Gill Ranch due to initial start-up costs and low storage contract revenues prior to April 1, 2011, which is the start of Gill Ranch's first injection season, and partly due to a slight downturn in revenues from firm storage and optimization services at Mist.

Gas storage net operating revenues (margin) decreased $0.1 million to $5.3 million for the three months ended March 31, 2011. This decrease in margin is primarily due to a decrease in Mist third-party optimization revenues of $0.8 million, partially offset by Gill Ranch's revenues of $0.6 million.

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 $1.1 million and $1.2 million as of March 31, 2011 and 2010, respectively, primarily reflecting a non-controlling minority interest in the Kelso-Beaver pipeline. Our net equity investment in PGH as of March 31, 2011 and 2010 was $14.8 million and $14.5 million, respectively. Earnings from our other business segment as of March 31, 2011 and 2010 was a net loss of less than $0.1 million and net income of $0.2 million, respectively. See Note 4 in the 2010 Form 10-K and in this report.

Consolidated Operations

Operations and Maintenance

Consolidated operations and maintenance expense was $31.2 million in 2011, compared to $30.7 million in 2010, a increase of $0.5 million or 2 percent. The following summarizes the major factors that contributed to changes in operations and maintenance expense for the three months ended March 31, 2011 compared to March 31, 2010:

- a $1.1 million increase for operating expenses at Gill Ranch, including $0.8 million for labor related expenses and $0.3 for compressor related expenses; and
- a $0.6 million increase in accrued performance bonuses at the utility based on above-target year-to-date operating results compared to last year.

Partially offsetting the above factors were:

- a $1.0 million decrease in consulting and legal fees due to prior year costs related to our successful property tax appeal;
- a $0.2 million decrease in utility bad debt expense (see below for further discussion); and
- a $0.2 million decrease in 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 0.18 percent for the twelve months ended March 31, 2011, compared to 0.33 percent for the same period last year. The decrease in our bad debt expense ratio was partly due to improved collections and recoveries of delinquent account balances. Despite these improvements, we believe 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 recovered in rates, which was set in our last general rate case. The pension expense deferral is recorded to a regulatory balancing account, which we expect to result in an estimated $4 to $5 million cumulative amount for 2011. So far, we have deferred $1.3 million of pension expense in the first quarter of 2011, which, when netted with pension expense, resulted in a $0.2 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

General taxes, which are principally comprised of property taxes, payroll taxes and regulatory fees, increased $4.9 million in the first three months of 2011 compared to 2010. The major factor that contributed to the change in general taxes was a prior year $5.2 million refund of property taxes pursuant to a favorable ruling from the Oregon Supreme Court (see below for further discussion).

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

Total depreciation and amortization expense in 2011 increased by $1.4 million, or 9 percent, as compared to the same period in 2010. The increased expense in 2011 was primarily related to Gill Ranch depreciation, which relates to assets that 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 March 31,	
Thousands	2011	2010
Gains from company-owned life insurance	$505	$396
Interest income	7	1,910
Income from equity investments	-	316
Net interest on deferred regulatory accounts	1,514	991
Gain (loss) on sale of investments	(96)	223
Other non-operating	(716)	(813)
Total other income and expense - net	$1,214	$3,023

Other income and expense – net decreased $1.8 million, 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 $0.5 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 of amounts capitalized in 2011 decreased by less than $0.1 million compared to 2010. The decrease is due to a $0.4 million savings from interest expense on long term debt as a result of bonds that matured in 2010, partially offset by a $0.2 million increase for gas storage related to the Gill Ranch base gas lease.

Income Tax Expense

The decrease in income tax expense of $2.2 million or 7 percent, compared to 2010 was primarily due to lower pre-tax consolidated earnings of $5.0 million or 7 percent and a decrease in our effective tax rate of 40.6 percent in 2011 compared to 40.8 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.

In July 2009, the governor of Oregon signed House Bill 3405 establishing increases in the state income tax rate for corporations, and Oregon voters approved this legislation in January 2010. The corporate income tax rate in Oregon increased from 6.6 percent to 7.9 percent for tax years 2009 and 2010 when taxable income is greater than $250,000. For tax years 2011 and 2012, the income tax rate will decrease to 7.6 percent, and for years after 2012 the tax rate will return to 6.6 percent, except for corporations with taxable income over $10 million the tax rate will remain at 7.6 percent.

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 March 31, 2011 and 2010 and at December 31, 2010 was as follows:

	March 31,				December 31,	
	2011		2010		2010	
Common stock equity	47.9	%	48.6	%	44.7	%
Long-term debt	36.5	%	42.2	%	38.1	%
Short-term debt, including current maturities of long-term debt	15.6	%	9.2	%	17.2	%
Total	100	%	100	%	100	%

Liquidity and Capital Resources

At March 31, 2011, we had $3.5 million of cash and cash equivalents compared to $8.8 million at March 31, 2010. We also had $0.9 million in restricted cash invested at Gill Ranch as of March 31, 2011, compared to $40.9 million at March 31, 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.

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 March 31, 2011, we could have been required to post $18.1 million of collateral to our counterparties, but that assumes our long-term debt ratings were at non-investment grade levels (see Note 13 and "Credit Ratings," below), which is several rating levels below our current ratings.

Business developments that could have a material impact on our liquidity and capital resource position include pension contributions, 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 50 percent bonus depreciation on a majority of our capital expenditures in 2010, and 100 percent bonus depreciation on qualified expenditures during 2011, which significantly reduces our tax liability for the 2010 and 2011 tax years, thereby providing cash flow benefits in 2011 (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 began commercial operations in the fourth quarter of 2010. Although we anticipate future operating cash flows at Gill Ranch to increase 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." The new legislation requires additional government regulation of derivative and over-the-counter transactions, and could expand collateral requirements. While we are currently evaluating the new legislation to determine its impact, 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, recent experience issuing commercial paper, current cash reserves, committed credit facilities and other liquidity resources, and our expected ability to issue long-term debt in the form of an MTN program 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 March 31, 2011, our purchase commitments increased approximately $28 million since December 31, 2010, primarily involving contracts entered into in the normal course of business (see "Financial Condition—Contractual Obligations," in the 2010 Form 10-K).

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 March 31, 2011 and 2010, our utility had commercial paper outstanding of $186.4 million and $56.0 million, respectively. The effective interest rate on the utility's commercial paper outstanding at March 31, 2011 and 2010 was 0.4 percent and 0.3 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 and bilateral credit agreements are major financial institutions with committed balances and investment grade credit ratings as of March 31, 2011 as follows:

	Loan Commitment Amounts in Thousands	
Lender rating, by category	Syndicated Facility	Bilateral Facility
AAA/Aaa	$ -	$ -
AA/Aa	230,000	50,000
A/A	20,000	-
BBB/Baa	-	-
Total	$ 250,000	$ 50,000

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 seven 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 March 31, 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 March 31, 2011 and 2010, with consolidated indebtedness to total capitalization ratios of 52 percent and 51 percent, respectively.

The syndicated and bilateral agreements 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).

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All three lenders under the short-term credit agreements are existing lenders under our syndicated credit agreement. The short-term credit agreements require us to comply with the terms and conditions of the syndicated credit agreement and give the lenders under the short-term credit agreements the same rights with respect to the short-term credit agreements that they have under the syndicated credit agreement. The bilateral credit agreement expired March 31, 2011.

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 three months ended March 31, 2011 and 2010 there were no long-term debt maturities or redemptions. Over the next twelve months, $10 million of secured MTNs, with a coupon rate of 6.665%, mature in June 2011, and another $40 million of secured MTNs, with a coupon rate of 7.13%, 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.

Cash Flows

Operating Activities

Three months ended March 31, 2011 compared to March 31, 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 year ended March 31, 2011, cash flow from operating activities totaled $108.1 million compared to $74.2 million in 2010. The significant factors contributing to changes in operating cash flow in the first three months of 2011 compared to 2010 are as follows:

- a decrease of $35.1 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 $17.3 million from changes in inventories primarily due the decreases in gas prices and increases in gas inventory withdrawals from storage in 2011 compared to 2010;

- an increase of $15.6 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 $13.5 million from deferred income taxes, primarily reflecting higher tax benefits from bonus

- depreciation taken from Gill Ranch capital investments placed in service;
- an increase of $10.6 million from income taxes receivable and accrued taxes, primarily related to our federal refund received in the first quarter of 2011 of $14.4 million; and
- an increase of $10.5 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 extends 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 March 31, 2011, we have a federal and state income tax receivable balance of $23.6 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 estimated net operating loss (NOL) for federal income tax purposes of $94.4 million, primarily due to the effects of accelerated tax depreciation provided by the 2010 Act. The federal NOL will be carried back to 2009 and partially utilized for a refund of taxes paid in prior years. The remaining NOL 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 loss carry-forwards in future years. The 2010 federal NOL would expire in 2031 if not used in earlier years.

Investing Activities

Cash used in investing activities for the three months ended March 31, 2011 totaled $25.5 million, down from $57.4 million for the same period in 2010. Capital expenditures were $25.4 million in the three months ended March 31, 2011, down from $52.8 million for the same period in 2010, of which $27.0 million of the decrease was due to non-utility construction activity primarily related to Gill Ranch.

In 2011, capital expenditures are estimated to be between $95 million and $105 million for the utility, excluding our proposed investment in long-term gas reserves (for further discussion, see Note 15). For non-utility development projects, we expect to spend between $5 million and $15 million total in 2011 for capital projects currently in process (see "Strategic Opportunities," above). Over the next five-year period 2011 through 2015, total utility capital expenditures are estimated at between $400 and $500 million, excluding the investment of approximately $250 million in gas reserves. 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. 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.

In 2011, 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, GTN. For more information, see Note 12 and "Strategic Opportunities—Pipeline Diversification," above.

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Financing Activities

Cash used in financing activities during the three months ended March 31, 2011 totaled $82.5 million, up from cash used of $16.4 million for the same period in 2010. Our short-term debt balances decreased $71.0 million in the three months ended March 31, 2011, compared to a decrease of $6.0 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. During the first quarter of 2011, we contributed $13.6 million into these plans. We anticipate making additional contributions of between $8 million and $10 million before year end. In 2010, we contributed a total of $10 million, and in 2009 we contributed a total of $25 million. 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 pension plan (Western States Plan) pursuant to our collective bargaining agreement. We made contributions totaling $0.1 million to the Western States Plan in both the three months ended March 31, 2011 and 2010, and we expect to contribute a total of $0.4 million during 2011.

Ratios of Earnings to Fixed Charges

For the three and twelve months ended March 31, 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 7.37, 3.63 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.

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 March 31, 2011, we had a regulatory asset of $117.5 million for deferred environmental costs, which includes $60.5 million for additional costs expected to be paid in the future and accrued interest of $15.3 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 this quarter. 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 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 March 31, 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).

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 March 31, 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
01/01/11 - 01/31/11	1,232	$45.81	-	-
02/01/11 - 02/28/11	21,417	45.76	-	-
03/01/11 - 03/31/11	11,006	47.16	-	-
Total	33,655	$46.22	2,124,528	$ 16,732,648

(1) During the quarter ended March 31, 2011, 23,503 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, 10,152 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 March 31, 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, 2011 to repurchase up to an aggregate of 2.8 million shares or up to an aggregate of $100 million. During the quarter ended March 31, 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.

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: May 4, 2011

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

NORTHWEST NATURAL GAS COMPANY

EXHIBIT INDEX
To
Quarterly Report on Form 10-Q
For Fiscal Year Ended
March 31, 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.
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.
101*	The following materials from Northwest Natural Gas Company Quarterly Report on Form 10-Q for the quarter ended March 31, 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.