NORTHWEST NATURAL GAS CO
Form 10-Q
May 06, 2010

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, 2010

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 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 [ ] 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, 2010, 26,563,978 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, 2010

PART I. FINANCIAL INFORMATION

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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;
- growth;
- development of projects;
- competition;
- exploration of new gas supplies;
- the benefits of liquefied natural gas;
- estimated expenditures;
- costs of compliance;
- credit exposures;
- potential efficiencies;
- impacts of new laws and regulations;
- outcomes of litigation and other administrative matters;
- projected obligations under retirement plans;
- adequacy of, and shift in, mix of gas supplies;
- adequacy of regulatory deferrals; and
- environmental, regulatory and insurance recovery.

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 caution you therefore 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 2009 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,” respectively.

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.

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NORTHWEST NATURAL GAS COMPANY
PART I. FINANCIAL INFORMATION
Consolidated Statements of Income
(Unaudited)

	Three Months Ended March 31,	
Thousands, except per share amounts	2010	2009
Operating revenues:		
Gross operating revenues	$286,529	$437,355
Less: Cost of sales	148,561	284,174
Revenue taxes	7,042	10,542
Net operating revenues	130,926	142,639
Operating expenses:		
Operations and maintenance	30,666	33,955
General taxes	3,249	8,491
Depreciation and amortization	15,901	15,522
Total operating expenses	49,816	57,968
Income from operations	81,110	84,671
Other income and expense - net	3,023	890
Interest charges - net of amounts capitalized	10,489	9,370
Income before income taxes	73,644	76,191
Income tax expense	30,036	28,828
Net income	$43,608	$47,363
Average common shares outstanding:		
Basic	26,538	26,501
Diluted	26,601	26,597
Earnings per share of common stock:		
Basic	$1.64	$1.79
Diluted	$1.64	$1.78
Dividends per share of common stock	$0.415	$0.395

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY
PART I. FINANCIAL INFORMATION
Consolidated Balance Sheets
(Unaudited)

Thousands	March 31, 2010	March 31, 2009	Dec. 31, 2009
Assets:			
Plant and property:			
Utility plant	$2,232,307	$2,158,946	$2,216,112
Less accumulated depreciation	691,420	663,417	682,060
Utility plant - net	1,540,887	1,495,529	1,534,052
Non-utility property	177,227	80,689	146,622
Less accumulated depreciation and amortization	10,887	9,665	10,540
Non-utility property - net	166,340	71,024	136,082
Total plant and property	1,707,227	1,566,553	1,670,134
Current assets:			
Cash and cash equivalents	8,839	10,341	8,432
Restricted cash	40,924	9,921	35,543
Accounts receivable	78,347	99,985	77,438
Accrued unbilled revenue	39,244	61,034	71,230
Allowance for uncollectible accounts	(3,999)	(4,948)	(3,125)
Regulatory assets - current	55,872	124,085	29,954
Fair value of non-trading derivatives	450	4,798	6,504
Inventories:			
Gas	61,918	82,182	71,672
Materials and supplies	9,235	9,846	9,285
Income taxes receivable	-	1,804	-
Prepayments and other current assets	15,481	16,418	21,302
Total current assets	306,311	415,466	328,235
Investments, deferred charges and other assets:			
Regulatory assets - non-current	331,962	284,166	316,536
Fair value of non-trading derivatives	5	189	843
Other investments	67,558	68,302	67,365
Other	15,970	17,691	16,139
Total investments, deferred charges and other assets	415,495	370,348	400,883
Total assets	$2,429,033	$2,352,367	$2,399,252

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY
PART I. FINANCIAL INFORMATION
Consolidated Balance Sheets
(Unaudited)

Thousands	March 31, 2010	March 31, 2009	Dec. 31, 2009
Capitalization and liabilities:			
Capitalization:			
Common stock - no par value; authorized 100,000 shares; outstanding 26,564, 26,504 and 26,533 shares at three months ended March 31, 2010 and 2009, and December 31, 2009, respectively	$ 338,012	$ 335,261	$ 337,361
Earnings invested in the business	361,310	332,900	328,712
Accumulated other comprehensive income (loss)	(5,870)	(4,323)	(5,968)
Total common stock equity	693,452	663,838	660,105
Long-term debt	601,700	587,000	601,700
Total capitalization	1,295,152	1,250,838	1,261,805
Current liabilities:			
Short-term debt	96,000	88,600	102,000
Long-term debt due within one year	35,000	-	35,000
Accounts payable	93,534	93,304	123,729
Taxes accrued	27,325	14,224	21,037
Interest accrued	12,232	11,215	5,435
Regulatory liabilities - current	36,032	46,475	46,628
Fair value of non-trading derivatives	39,365	107,461	19,643
Other current and accrued liabilities	36,060	41,414	39,097
Total current liabilities	375,548	402,693	392,569
Deferred credits and other liabilities:			
Deferred income taxes and investment tax credits	311,691	267,827	300,898
Regulatory liabilities - non-current	247,517	239,561	248,622
Pension and other postretirement benefit liabilities	118,848	140,318	127,687
Fair value of non-trading derivatives	18,637	15,387	3,193
Other	61,640	35,743	64,478
Total deferred credits and other liabilities	758,333	698,836	744,878
Commitments and contingencies (see Note 10)	-	-	-
Total capitalization and liabilities	$ 2,429,033	$ 2,352,367	$ 2,399,252

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY
PART I. FINANCIAL INFORMATION
Consolidated Statements of Cash Flows
(Unaudited)

	Three Months Ended March 31,	
Thousands	2010	2009
Operating activities:		
Net income	$43,608	$47,363
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and amortization	15,901	15,522
Deferred income taxes and investment tax credits	11,517	9,848
Undistributed gains from equity investments	(356)	(288)
Deferred gas costs - net	(15,428)	33,974
Contributions to company's qualified defined benefit pension plans	(10,000)	-
Non-cash expenses related to qualified defined benefit pension plans	2,001	2,490
Deferred environmental expenditures	(3,632)	(2,669)
Settlement of interest rate hedge	-	(10,096)
Deferred regulatory costs and other	(2,431)	(16,101)
Changes in working capital:		
Accounts receivable and accrued unbilled revenue - net	31,951	25,837
Inventories of gas, materials and supplies	9,804	4,039
Income taxes receivable	-	19,007
Prepayments and other current assets	5,821	3,677
Accounts payable	(24,882)	(928)
Accrued interest and taxes	13,085	10,199
Other current and accrued liabilities	(2,803)	5,013
Cash provided by operating activities	74,156	146,887
Investing activities:		
Investment in utility plant	(17,011)	(21,641)
Investment in non-utility property	(35,763)	(6,171)
Net proceeds from (contributions to) non-utility equity investments	-	(900)
Increase in restricted cash	(5,381)	(5,802)
Other	782	439
Cash used in investing activities	(57,373)	(34,075)
Financing activities:		
Common stock issued (purchased), net of expenses	566	(1,184)
Long-term debt issued	-	75,000
Change in short-term debt - net	(6,000)	(172,251)
Cash dividend payments on common stock	(11,011)	(10,468)
Other	69	(484)
Cash used in financing activities	(16,376)	(109,387)
Increase in cash and cash equivalents	407	3,425
Cash and cash equivalents - beginning of period	8,432	6,916
Cash and cash equivalents - end of period	$8,839	$10,341

Supplemental disclosure of cash flow information:		
Interest paid	$3,325	$816
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. Summary of Significant Accounting Policies

Organization and Principles of Consolidation

The consolidated financial statements include the accounts of Northwest Natural Gas Company (NW Natural), primarily consisting of our regulated gas distribution business and our regulated gas storage business, which includes our wholly-owned subsidiary Gill Ranch Storage, LLC (Gill Ranch), and other investments and business activities, which primarily consist of our wholly-owned subsidiary NNG Financial Corporation (Financial Corporation) and an equity investment in a natural gas transmission pipeline (Palomar) (see Note 2 and Note 11). Investments in corporate joint ventures and partnerships in which we are not the primary beneficiary are accounted for by the equity method or the cost method.

In this report, the term "utility" is used to describe the gas distribution business and the term "non-utility" is used to describe the gas storage business and other non-utility investments and business activities (see Note 2). Intercompany accounts and transactions have been eliminated, except for transactions required to be included under regulatory accounting standards to reflect the effect of such regulation.

The information presented in the 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 2009 Annual Report on Form 10-K (2009 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 1 of the 2009 Form 10-K. There were no material changes to those accounting policies during the three months ended March 31, 2010. See below for a further discussion of newly adopted standards and recent accounting pronouncements.

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Industry Regulation

At March 31, 2010 and 2009 and at December 31, 2009, the amounts deferred as regulatory assets and liabilities were as follows:

	Current		
Thousands	March 31, 2010	March 31, 2009	Dec. 31, 2009
Regulatory assets:			
Unrealized loss on non-trading derivatives(1)	$39,365	$107,461	$19,643
Pension and other postretirement benefit obligations(2)	7,502	8,074	7,502
Other(3)	9,005	8,550	2,809
Total regulatory assets	$55,872	$124,085	$29,954
Regulatory liabilities:			
Gas costs payable	$26,164	$31,925	$37,055
Unrealized gain on non-trading derivatives(1)	450	4,798	6,504
Other(3)	9,418	9,752	3,069
Total regulatory liabilities	$36,032	$46,475	$46,628

	Non-Current		
Thousands	March 31, 2010	March 31, 2009	Dec. 31, 2009
Regulatory assets:			
Unrealized loss on non-trading derivatives(1)	$18,637	$15,387	$3,193
Income tax asset	75,515	70,096	76,240
Pension and other postretirement benefit obligations(2)	108,010	111,851	109,932
Environmental costs - paid(4)	49,836	38,804	46,204
Environmental costs - accrued but not yet paid(4)	57,701	28,977	59,844
Other(3)	22,263	19,051	21,123
Total regulatory assets	$331,962	$284,166	$316,536
Regulatory liabilities:			
Gas costs payable	$2,377	$9,201	$6,915
Unrealized gain on non-trading derivatives(1)	5	189	843
Accrued asset removal costs	242,952	227,770	238,757
Other(3)	2,183	2,401	2,107
Total regulatory liabilities	$247,517	$239,561	$248,622

(1) An unrealized gain or loss on non-trading 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 PGA mechanism.

(2) Certain qualified pension plan and other postretirement benefit obligations are approved for regulatory deferral. Such amounts are recoverable in rates, including an interest component, when recognized in net periodic benefit cost (see Note 7).

(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 those sites that are approved for regulatory deferral. We earn the 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.

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New Accounting Standards

Adopted Standards

Variable Interest Entity. Effective January 1, 2010, we adopted authoritative guidance on variable interest entities (VIE). This guidance requires an analysis to determine whether we are the primary beneficiary of our VIEs. As the primary beneficiary, we would be considered to have a controlling financial interest in the VIE. The guidance defines the primary beneficiary as the entity having:

- power to control the activities that most significantly impact the performance; and
- the obligation to absorb losses or right to receive benefits from the entity that could potentially be significant to the VIE.

If we are considered the primary beneficiary of a VIE, we would be required to consolidate the VIE on our financial statements. The adoption of this standard did not have a material effect on our financial condition, results of operations or cash flows; however, if we are required to consolidate VIEs in future periods, it could have a material impact on our financial statements.

Subsequent Events. Effective February 2010, we adopted authoritative guidance on subsequent events, which clarifies the requirement to evaluate subsequent events through the date that the financial statements are issued but does not require disclosure of the date through which subsequent events have been evaluated. The adoption of this standard did not have, and is not expected to have a material effect on our financial statement disclosures.

Recent Accounting Pronouncements

Fair Value Disclosures. In January 2010, the Financial Accounting Standards Board issued authoritative guidance on fair value measures 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 are effective for periods beginning after December 15, 2010; however, we elected to early adopt these disclosure requirements, as shown in Note 7 of our 2009 Form 10-K. The adoption of this standard did not have, and is not expected to have, a material effect on our financial statement disclosures.

Earnings Per Share

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

	Three Months Ended March 31,	
Thousands, except per share amounts	2010	2009
Net income	$43,608	$47,363
Average common shares outstanding - basic	26,538	26,501
Additional shares for stock-based compensation plans	63	96
Average common shares outstanding - diluted	26,601	26,597
Earnings per share of common stock - basic	$1.64	$1.79
Earnings per share of common stock - diluted	$1.64	$1.78

For the three months ended March 31, 2010 and 2009, 5,120 and 6,891 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.

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2. 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 Gill Ranch and a portion of the Mist underground storage facility in Oregon, and our "other" segment includes our equity investment in Palomar and Financial Corporation.

The following table presents information about the reportable segments for the three months ended March 31, 2010 and 2009. Inter-segment transactions are insignificant.

	Three Months Ended March 31			
Thousands	Utility	Gas Storage	Other	Total
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
2009				
Net operating revenues	$138,094	$4,500	$45	$142,639
Depreciation and amortization	15,183	339	-	15,522
Income from operations	80,894	3,745	32	84,671
Net income	45,304	2,032	27	47,363
Total assets at March 31, 2009	2,244,899	88,991	18,477	2,352,367
Total assets at December 31, 2009	2,205,313	173,648	20,291	2,399,252

Variable Interest Entities

Our Palomar project, a joint venture owned 50 percent by us and 50 percent by TransCanada Corporation, is a proposed natural gas transmission pipeline in Oregon designed to serve our utility and the growing natural gas markets in Oregon and other parts of the western United States. As of March 31, 2010, we have determined that Palomar is a VIE and that we are not the primary beneficiary of Palomar's activities as defined by the authoritative guidance related to consolidations. We account for Palomar under the equity method, and our equity investment balance at March 31, 2010 and 2009 was $14.5 million and $15.5 million, respectively, which was included in other investments on our balance sheet. The decrease in our equity balance over the last 12 months is due to a $5.2 million cash distribution by Palomar to NW Natural, partially offset by $2.7 million in equity contributions plus $1.5 million of income allocation based on our 50 percent ownership interest. Our maximum loss exposure related to Palomar as of March 31, 2010 is limited to our equity investment balance of $14.5 million. Our loss exposure would be reduced by any credit support recovered from third parties should they default on current agreements. See Note 11, for an update on Palomar since March 31, 2010.

3. Capital Stock

As of March 31, 2010, our common shares authorized were 100,000,000 and our outstanding shares were 26,563,978.

We have a share repurchase program for our common stock under which we may purchase shares on the open market or through privately negotiated transactions. We currently have Board authorization through May 31, 2010 to repurchase up to an aggregate of 2.8 million shares, or up to $100 million. No shares of common stock were repurchased under this program during the three months ended March 31, 2010, and since inception in 2000 a total of 2.1 million shares have been repurchased at a total cost of $83.3 million.

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4. 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 the 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 4, in the 2009 Form 10-K and current updates provided below.

Long-Term Incentive Plan. On February 24, 2010, 41,500 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 $25.64 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	$44.25	
Performance term (in years)	3.0	
Quarterly dividends paid per share	$0.415	
Expected dividend yield	3.7	%
Dividend discount factor	0.8949	

In February 2010, the Board approved a payout of performance-based stock awards for the 2007-09 award period. Shares of common stock were purchased on the open market to satisfy the approved awards.

Restated Stock Option Plan. On February 24, 2010, options to purchase 119,750 shares were granted under the Restated SOP, with an exercise price equal to the closing market price of $44.25 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 $6.36 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	2.3	%
Expected life (in years)	4.7	
Expected market price volatility factor	23.2	%
Expected dividend yield	3.8	%
Forfeiture rate	3.2	%

As of March 31, 2010, there was $1.3 million of unrecognized compensation cost related to the unvested portion of outstanding stock option awards expected to be recognized over a period extending through 2013.

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

Cost of Long-Term Debt

Our long-term debt consists of medium-term notes (MTNs) that have maturity dates from 2010 through 2035, and have interest rates ranging from 3.95 percent to 9.05 percent with an average interest rate of 6.19 percent. For the three months ended March 31, 2010 we did not issue or redeem any secured medium-term notes. In March 2009, we issued $75 million of 5.37 percent secured MTNs due February 1, 2020, and in July 2009, we issued another $50 million of secured MTNs with an interest rate of 3.95 percent and a maturity of July 15, 2014. Proceeds from these MTNs were used to fund utility capital expenditures, to redeem utility short-term debt, and to provide utility working capital for general corporate purposes.

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Fair Value of Long-Term Debt

The following table provides an estimate of the fair value of our 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 debt that actively trades with similar credit ratings, terms and remaining maturities to estimate fair value for our long-term debt issues.

	March 31, 2010		Dec. 31, 2009	
Thousands	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Long-term debt including amounts due within one year	$ 636,700	$ 687,937	$ 636,700	$ 707,755

6. Pension and Other Postretirement Benefits

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	2010	2009	2010	2009
Service cost	$1,773	$1,663	$156	$147
Interest cost	4,491	4,492	343	406
Expected return on plan assets	(4,564)	(3,995)	-	-
Amortization of net actuarial loss	1,768	1,659	7	4
Amortization of prior service cost	206	306	49	49
Amortization of transition obligation	-	-	103	103
Net periodic benefit cost	3,674	4,125	658	709
Amount allocated to construction	(953)	(1,178)	(208)	(232)
Net amount charged to expense	$2,721	$2,947	$450	$477

See Part II, Item 8., Note 7, in the 2009 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 Western States Plan is managed by a board of trustees that includes equal representation from participating employers and labor unions. Contribution rates are established by collective bargaining agreements and benefit levels are set by the board of trustees based on the advice of an independent actuary regarding the level of benefits that agreed-upon contributions are expected to support. As of January 1, 2010, the Western States Plan had an accumulated funding deficiency for the current plan year and remained in "critical status." Federal law requires pension plans in critical status to adopt a rehabilitation plan designed to restore the financial health of the plan. Rehabilitation plans may specify benefit reductions, contribution surcharges, or a combination of the two. We made contributions totaling $0.1 million to the Western States Plan for both the three months ended March 31, 2010 and 2009. The Western States Plan board of trustees imposed a 5 percent contribution surcharge to participating employers, including NW Natural, beginning in August 2009, which increased to a 10 percent contribution surcharge beginning January 2010. The board of trustees adopted a rehabilitation plan that reduced benefit accrual rates and adjustable benefits for active employee participants and increases future employer contribution rates. These changes are expected to improve the funding status of the plan. Contribution surcharges above 10 percent will be assessed to employer participants, but these higher surcharges will not go into effect for NW Natural until its next collective bargaining agreement, which is expected to be no earlier than June 1, 2014. Under the terms of our collective bargaining agreement, which became effective in July 2009, we can withdraw from the Western States Plan at any time. If we withdraw and the plan is underfunded, we could be assessed a withdrawal liability. We have no current intent to withdraw from the plan, so we have not recorded a withdrawal liability.

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Employer Pension Contributions

In February 2010, we made a $10 million cash contribution to our qualified defined benefit pension plans, portions of which were for the 2009 and 2010 plan years. In addition, we made cash contributions for our unfunded, non-qualified pension plans and other postretirement benefit plans. For more information see Part II, Item 8., Note 7, in the 2009 Form 10-K.

7. Income Tax

The effective income tax rate for the three months ended March 31, 2010 and 2009 varied from the U.S. federal statutory rate principally due to the following:

	March 31, 2010		2009	
Federal statutory tax rate	35.0	%	35.0	%
Increase (decrease):				
Current state income tax, net of federal tax benefit	4.9	%	3.9	%
Amortization of investment and energy tax credits	-0.5	%	-0.5	%
Differences required to be flowed-through by regulatory commissions	1.5	%	-0.1	%
Gains on company and trust-owed life insurance	-0.2	%	-0.6	%
Other - net	0.1	%	0.1	%
Effective tax rate	40.8	%	37.8	%

The increase in our effective tax rate for the first quarter of 2010 compared to the first quarter of 2009 was primarily due to the increase in the Oregon statutory tax rate from 6.6 percent to 7.9 percent and an increase in the amortization rate of our regulatory tax asset pursuant to a regulatory order effective November 1, 2009, which we will mostly recover in rates.

8. Comprehensive Income

Items excluded from net income and charged directly to common stock equity are included in accumulated other comprehensive income (loss), net of tax. The amount of accumulated other comprehensive loss in common stock equity is $5.9 million and $4.3 million as of March 31, 2010 and 2009, 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, 2010 and 2009.

Thousands	Three Months Ended March 31, 2010	2009
Net income	$ 43,608	$ 47,363
Amortization of employee benefit plan liability, net of tax	98	63
Total comprehensive income	$ 43,706	$ 47,426

9. Derivative Instruments

We enter into swaps, options and combinations of options for the purchase of natural gas and for the forecasted issuance of fixed-rate debt that qualify as derivative instruments under accounting for derivative instruments and hedging activities. We primarily use derivative financial instruments to manage commodity prices related to our natural gas requirements and to manage interest rate risk exposure related to our long-term debt issuances.

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 Purchased Gas Adjustment (PGA) filing receive regulatory deferred accounting treatment. Derivative contracts entered into for core utility customer requirements after the annual PGA rate was set on November 1, 2009, are subject to the PGA incentive sharing mechanism, which provides for 90 percent of the changes in fair value to be deferred as regulatory assets or liabilities and the remaining 10 percent to be recorded to the income statement for contracts not qualifying for cash flow hedge accounting and to other comprehensive income for contracts qualifying for cash flow hedge accounting.

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We do most of our hedging for the upcoming gas year prior to the start of that gas year and include the hedge prices in our annual PGA filing. We hedge our anticipated year-round sales volumes based on normal weather. We entered the 2009-10 gas year (November 1, 2009 – October 31, 2010) hedged at a targeted level of approximately 75 percent, including 60 percent financially hedged and 15 percent physically hedged through gas storage. Our policy allows us to hedge price risk for up to 100 percent of our gas supplies for the next gas year and up to 50 percent for the following gas year.

At March 31, 2010 and 2009, we were hedged with financial contracts for the next gas year at approximately 32 percent and 30 percent, respectively, based on anticipated sales volumes. At March 31, 2010, we were also hedged with financial contracts for the 2011-12 gas year between 10 and 15 percent, while at March 31, 2009, we had no hedges for the 2010-11 gas year.

The following table discloses the balance sheet presentation of our derivative instruments as of March 31, 2010, and 2009 and December 31, 2009:

	Fair Value of Derivative Instruments					
Thousands	March 31, 2010		March 31, 2009		December 31, 2009	
	Current	Non-Current	Current	Non-Current	Current	Non-Current
Assets (1)						
Commodity contracts	$433	$ 5	$4,798	$ 189	$6,214	$ 843
Foreign exchange contracts	17	-	-	-	290	-
Total	$450	$ 5	$4,798	$ 189	$6,504	$ 843
Liabilities (2)						
Commodity contracts	$39,365	$ 18,637	$107,307	$ 15,387	$19,643	$ 3,193
Foreign exchange contracts	-	-	154	-	-	-
Total	$39,365	$ 18,637	$107,461	$ 15,387	$19,643	$ 3,193

(1) Unrealized fair value gains are classified under current- or non-current assets as fair value of non-trading derivatives.
(2) Unrealized fair value losses are classified under current- or non-current liabilities as fair value of non-trading derivatives.

The following table discloses the income statement presentation for the unrealized gains and losses from our derivative instruments for the three months ended March 31, 2010 and 2009. All of our currently outstanding derivative instruments are related to regulated utility operations as illustrated by the derivative gains and losses being deferred to balance sheet accounts in accordance with regulatory accounting.

	March 31, 2010		March 31, 2009	
Thousands	Commodity contracts (1)	Foreign exchange contracts (2)	Commodity contracts (1)	Foreign exchange contracts (2)
Cost of sales	$ (57,564)	$ -	$ (117,707)	$ -
Other comprehensive income	-	17	-	(154)
Less:				
Amounts deferred to regulatory accounts on balance sheet	57,564	(17)	117,707	154
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 exchange forward purchase contracts is recorded in other comprehensive income, and reclassified to regulatory deferral accounts on the balance sheet.

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Our derivative liabilities exclude the netting of collateral. We had no collateral posted with our counterparties as of March 31, 2010. We attempt to minimize the potential exposure to collateral calls by our counterparties to manage our liquidity risk. Based on our current credit rating, most counterparties allow us credit limits ranging from $15 million to $25 million before collateral postings are required. Our collateral call exposure is set forth under credit support agreements, which generally contain credit limits based on our debt ratings. We also could be subject to collateral call exposure where we have agreed to provide adequate assurance, which is not specific as to amount of credit limit allowed, but could potentially require additional collateral in the event of a material adverse change. Based upon the current unrealized loss of $57.5 million, the fair value associated with estimated collateral calls is shown in the table below. The following table discloses the estimates with and without potential adequate assurance calls, using outstanding derivative instruments at March 31, 2010, based on current gas prices and with various credit rating scenarios for NW Natural.

Thousands	A+/A3 (Current Ratings)	BBB+/Baa1	BBB/Baa2	BBB-/Baa3	Speculative
With Adequate Assurance Calls	$ -	$ -	$ -	$ 3.2	$ 23.1
Without Adequate Assurance Calls	$ -	$ -	$ -	$ 3.2	$ 23.1

In the three months ended March 31, 2010, we realized net losses of $6.2 million from the settlement of natural gas hedge contracts, which were recorded as increases to the cost of gas, compared to net losses of $79.3 million for the three months ended March 31, 2009. The currency exchange rate in all foreign currency forward purchase contracts is included in our purchased cost of gas at settlement; therefore, no gain or loss is recorded from the settlement of those contracts. We settled our $50 million interest rate swap in March 2009 concurrent with our issuance of the underlying long-term debt and realized a $10.1 million effective hedge loss, which is being amortized to interest expense over the term of the debt.

We are exposed to derivative credit risk primarily through securing pay-fixed natural gas commodity swaps to hedge the risk of price increases for our natural gas purchases on behalf of customers. We utilize master netting arrangements through International Swaps and Derivatives Association contracts to minimize this risk along with collateral support agreements with counterparties based on their credit ratings. In certain cases we require guarantees or letters of credit in order for a counterparty to meet our credit requirements.

Our financial derivatives policy requires counterparties to have a certain investment-grade credit rating at the time the derivative instrument is entered into, and the policy specifies limits on the contract amount and duration based on each counterparty’s credit rating. We do not speculate on derivatives; rather, we utilize derivatives to hedge our exposure above risk tolerance limits. Any increase in market risk created by the use of derivatives should be offset by the exposures they modify.

We actively monitor our derivative credit exposure and place counterparties on hold for trading purposes or require other forms of credit assurance, such as letters of credit, cash collateral or guarantees as circumstances warrant. Our ongoing assessment of counterparty credit risk includes consideration of credit ratings, credit default swap spreads, bond market credit spreads, financial condition, government actions and market news. We utilize a Monte-Carlo simulation model to estimate the change in credit and liquidity risk from the volatility of natural gas prices. We use the results of the model to establish at-risk trading limits. The duration of our credit risk for all outstanding derivatives currently does not extend beyond October 31, 2012.

We could become materially exposed to credit risk with one or more of our counterparties if natural gas prices experience a significant increase. If a counterparty were to become insolvent or fail to perform on its obligations, we could suffer a material loss, but we would expect such loss to be eligible for regulatory deferral and rate recovery, subject to prudency review. All of our existing counterparties currently have investment-grade credit ratings.

Fair Value Assessment

In accordance with fair value accounting, we include non-performance 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, 2010.

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The following table provides the fair value hierarchy of our derivative assets and liabilities as of March 31, 2010 and 2009 and December 31, 2009:

Thousands	Description of Derivative Inputs	March 31, 2010	March 31, 2009	Dec. 31, 2009
Level 1	Quoted prices in active markets	$-	$-	$-
Level 2	Significant other observable inputs	(57,547)	(117,861)	(15,489)
Level 3	Significant unobservable inputs	-	-	-
		$(57,547)	$(117,861)	$(15,489)

10. Commitments and Contingencies

Environmental Matters

We own, or have 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 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 environmental site investigations, the range of potential loss beyond the amounts currently accrued, and the probabilities thereof, cannot currently be reasonably estimated. See Part II, Item 8., Note 11, in the 2009 Form 10-K.

The status of each site 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 (the 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 Upland Remediation Investigation Report and submitted it to the ODEQ for review. In November 2007, we submitted a Focused Feasibility Study (FFS) for groundwater source control which ODEQ conditionally approved in March 2008. ODEQ provided conditional approval of the Focused Feasibility Study and the design of the source control system is currently underway. During the third quarter of 2009, we signed a joint Order on Consent with the Environmental Protection Agency (EPA) which requires the design of a final remedial action for the Gasco sediments. We have a liability accrued of $52.1 million at March 31, 2010 for the Gasco site, which is estimated 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.

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, 2010 for the Siltronic site is $1.2 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 the 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 2010. 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 2008, we received a revised estimate for additional expenditures related to RI/FS development and environmental remediation. 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, 2010, we have a liability accrued of $8.9 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.

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In April 2004, we entered into an Administrative Order on Consent providing for early action removal of a deposit of tar in the river sediments adjacent to the Gasco site. We completed this removal of the tar deposit in the Portland Harbor in October 2005, and on November 5, 2005 the EPA approved the completed project. The total cost of removal, including technical work, oversight, consultant fees, legal fees and ongoing monitoring, was about $9.9 million. To date, we have paid $9.5 million on work related to the removal of the tar deposit. As of March 31, 2010, we have a liability accrued of $0.4 million for our estimate of ongoing costs related to this tar deposit removal.

Central Service Center site. In 2006, we received notice from the ODEQ that our Central Service Center in southeast Portland (the 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 2007, 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 the 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, 2010, 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. Although it is 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 have been submitted to ODEQ. ODEQ approval of the work plans has been received and studies are underway. As of March 31, 2010, we have an estimated liability accrued of $0.3 million for the study of the site, which will include investigation of sediments and provide a report of historical upland activities. 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, 2010 and 2009 and December 31, 2009:

	Current Liabilities			Non-Current Liabilities		
Thousands	March 31, 2010	March 31, 2009	Dec. 31, 2009	March 31, 2010	March 31, 2009	Dec. 31, 2009
Gasco site	$ 9,924	$ 8,457	$ 9,841	$ 42,165	$ 10,935	$ 43,659
Siltronic site	679	831	653	508	114	593
Portland Harbor site	1,873	-	2,114	7,041	13,191	7,272
Central Service Center site	5	-	5	511	526	511
Front Street site	72	294	72	252	-	436
Other sites	-	-	-	106	64	123
Total	$ 12,553	$ 9,582	$ 12,685	$ 50,583	$ 24,830	$ 52,594

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Regulatory and Insurance Recovery for Environmental Costs. In May 2003, the Oregon Regulatory Commission (OPUC) approved our request to defer unreimbursed environmental costs associated with certain named sites, including those described above. Beginning in 2006, the OPUC also authorized us 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 deferral and interest accrual has been extended through January 2011.

On a cumulative basis, we have recognized a total of $101.9 million for environmental costs, including legal, investigation, monitoring and remediation costs and a net liability of $63.1 million. At March 31, 2010, we had a regulatory asset of $107.5 million, which includes $39.3 million of total paid expenditures to date, $57.7 million for additional environmental costs expected to be paid in the future and accrued interest of $10.5 million. We believe the recovery of these deferred charges is probable through the regulatory process. We intend to pursue recovery of an insurance receivable and environmental regulatory deferrals from insurance carriers under our general liability insurance policies, and the regulatory asset will be reduced by the amount of any corresponding insurance recoveries. We consider insurance recovery of most of our environmental costs probable based on a combination of factors including: a review of the terms of our insurance policies; the financial condition of the insurance companies providing coverage; a review of successful claims filed by other utilities with similar gas manufacturing facilities; and Oregon law that allows an insured party to seek recovery of “all sums” from one insurance company. We have initiated settlement discussions with a majority of our insurers. In the event that settlements cannot be reached, we may pursue other legal remedies. We continue to anticipate that our overall insurance recovery effort will extend over several years.

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, 2010 and 2009 and December 31, 2009:

	Non-Current Regulatory Assets		
Thousands	March 31, 2010	March 31, 2009	Dec. 31, 2009
Gasco site	$70,411	$31,493	$69,607
Siltronic site	3,020	2,223	2,974
Portland Harbor site	32,140	32,820	31,500
Central Service Center site	550	548	550
Front Street site	1,032	347	910
Other sites	384	350	507
Total	$107,537	$67,781	$106,048

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, including the matter described below, cannot be predicted with certainty, 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. 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.

11. Subsequent Event

On May 5, 2010, we learned that the shipper which had proposed to build a liquefied natural gas terminal on the Columbia River had suspended its plans and filed for bankruptcy protection. Palomar had previously entered a precedent agreement with that shipper for a majority of the capacity on the proposed Palomar pipeline. NW Natural owns 50 percent of Palomar Gas Holdings (PGH), and the other 50 percent is owned by Gas Transmission Corporation (GTN), a subsidiary of TransCanada Corporation. Palomar Gas Transmission, LLC, a wholly-owned subsidiary of PGH, is building the Palomar pipeline. As a result of such shipper's suspension of operations and bankruptcy filing, PGH is evaluating the impact on the development of the Palomar project, particularly with respect to the 106-mile west segment. Although the full impact cannot be determined at this time, we expect PGH will reconsider whether to proceed with the pipeline's west segment and we will correspondingly evaluate any impact on our own financial statements, including whether NW Natural should now be considered the primary beneficiary of Palomar, a VIE under accounting rules. If NW Natural is determined to be this VIE's primary beneficiary, then we would be required to consolidate Palomar on our financial statements. We will also be updating our impairment analysis during the second quarter of 2010, but at this time we do not expect our investment in Palomar to be impaired based on the amount of credit support available for the pipeline's west segment and on the continuing support for development of the pipeline's east segment. As of March 31, 2010, our equity investment balance in Palomar was $14.5 million.

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NORTHWEST NATURAL GAS COMPANY
PART I. FINANCIAL INFORMATION

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. This discussion refers to our consolidated activities for the three months ended March 31, 2010 and 2009. 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 2009 Annual Report on Form 10-K (2009 Form 10-K).

The consolidated financial statements include the accounts of NW Natural and its wholly-owned subsidiaries, NNG Financial Corporation (Financial Corporation) and Gill Ranch Storage, LLC (Gill Ranch), and an equity investment in a proposed natural gas pipeline. These accounts include our regulated local gas distribution business, our regulated gas storage business, and other regulated and non-regulated investments primarily in energy-related businesses. In this report, the term "utility" is used to describe our regulated local gas distribution segment, and the term "non-utility" is used to describe our gas storage segment (gas storage) as well as our other regulated and non-regulated investments and business activities (other segment) (see "Strategic Opportunities," below, and Note 2).

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 earnings. All references in this section to earnings per share are on the basis of diluted shares (see Part II, Item 8., Note 1, "Earnings Per Share," in our 2009 Form 10-K).

Executive Summary

Results for the first quarter of 2010 include:

- Consolidated net income decreased 8 percent from $47.4 million in the first quarter of 2009 to $43.6 million, in the first quarter of 2010;
  - Net operating revenues decreased 8 percent from $142.6 million in 2009 to $130.9 million in 2010;
- Earnings from utility operations decreased 10 percent from net income of $45.3 million in 2009 to net income of $40.9 million in 2010;
- Earnings from gas storage operations increased 23 percent from net income of $2.0 million in 2009 to $2.5 million in 2010;
  - Total operating expenses decreased 14 percent from $58.0 million in 2009 to $49.8 million in 2010;
- Cash flow from operations contributed $74.2 million in the first quarter of 2010 compared to $146.9 in the first quarter of 2009; and
- Twelve-month customer growth rate was 0.7 percent.

Issues, Challenges and Performance Measures

Economic weakness. Ongoing weakness in local and U.S. economies have continued to impact consumer demand and business spending. These conditions may continue to have a negative impact on our financial results, reflecting slower customer growth, reduced industrial margins, increased bad debt expense, and higher pension costs. Most recently, our annual customer growth rate was 0.7 percent at March 31, 2010 compared to 1.2 percent at March 31,

2009. Our customer growth rate over the last three quarters has stabilized at a range of 0.7 percent to 0.8 percent. Despite challenging market conditions, we believe we are well positioned to continue adding customers due to our relatively low market penetration, our efforts to convert homes to natural gas, and the potential for environmental initiatives that could favor natural gas use in our region.

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Managing gas prices and supplies. Our gas acquisition strategy is designed to secure sufficient supplies of natural gas to meet the needs of our utility customers and to hedge gas prices to effectively manage costs, reduce price volatility and maintain a competitive advantage. We entered the 2009-10 gas year, which began November 1, 2009, hedged at a targeted level of approximately 75 percent of our estimated gas purchase volumes for the gas contract year, and we had secured sufficient supplies to meet the needs of our core utility customers. In addition, we are currently hedged on gas prices for 32 percent of our forecasted purchase volumes for the next gas year and for between 10 and 15 percent for the following year. Our policy allows us to hedge up to 100 percent of our gas supply requirements for the next gas year and up to 50 percent for the following year. Our Purchased Gas Adjustment (PGA) mechanism, along with gas price hedging strategies and gas supplies in storage, enables us to reduce earnings risk exposure to higher gas costs. In addition to hedging gas prices over the next three years, we are also evaluating and developing other gas acquisition strategies to potentially manage gas price volatility for customers beyond three years.

Environmental investigation and remediation 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 required to defer certain costs pursuant to regulatory decisions by the Oregon Public Utility Commission (OPUC) or Washington Utility Transportation Commission (WUTC), including environmental costs, and to seek recovery of these amounts in future rates to customers. However, before we can seek recovery from customers, we must 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 costs and demonstrate that costs 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 Note 10 in this report and Note 11 in our 2009 Form 10-K.

Climate change. We recognize that our businesses are likely to be impacted by future carbon constraints. The outcome of federal, state, local and international climate change initiatives cannot be determined at this time, but these initiatives could produce a number of results including potential new regulations, additional charges to fund energy efficiency activities, or other regulatory actions. While our CO2 equivalent emission levels are relatively small, the adoption and implementation of any regulations imposing reporting obligations, or limiting emissions of greenhouse gases associated with our operations, could result in an increase in the prices we charge our customers or a decline in the demand for natural gas. On the other hand, because natural gas has a relatively low carbon content, it is also possible that future carbon constraints could create additional demand for natural gas for electric production, direct use in homes and businesses and as a reliable and relatively low-emission back-up fuel source for alternative energy sources.

Strategies and Performance Measures. In order to deal with the challenges affecting our business, 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 core gas distribution business; 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 new clean energy technologies. We intend to measure our performance and monitor progress of 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; capital, 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 integrate, consolidate and streamline operations and support our employees with new technology tools.

In 2009, we announced a voluntary severance program to reduce staffing levels in response to work load declines related to the current low customer growth environment and efficiency improvements. Severance programs and normal attrition resulted in reductions of full-time positions from 1,133 at December 31, 2008 to approximately 1,018 at March 31, 2010, which are reflected in decreases in operation and maintenance costs and utility capital expenditures.

Technology investments, workforce reductions and other initiatives discussed above are expected to facilitate process improvements, contribute to long-term operational efficiencies and reduce operating and capital costs throughout NW Natural.

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Gas Storage Development. In 2007, we entered into a joint project agreement with Pacific Gas & Electric Company (PG&E) to develop, own through undivided ownership interests, and operate an underground natural gas storage facility near Fresno, California. Our undivided ownership interest in the project is held by our wholly-owned subsidiary, Gill Ranch. Gill Ranch is planning and developing the project and upon completion will operate the facility. Gill Ranch’s provision of market-based rate storage services in California will be subject to California Public Utility Commission (CPUC) regulation including, but not limited to, service terms and conditions, tariff compliance, securities issuances, lien grants and sales of property. Construction began in January 2010. Our share of the total project cost has been revised due to recent weather delays, permit requirements and other cost increases and is currently estimated to be between $185 million and $205 million, up from our prior estimate of $160 million to $180 million. Our share represents 75 percent of the total cost of the initial development, which includes an estimated total 20 Bcf of gas storage capacity and approximately 27 miles of gas transmission pipeline. The initial development of the gas storage facility at Gill Ranch is currently targeted to be in-service by the end of the third quarter of 2010, and we are currently hiring key staff for our non-utility gas storage business.

We plan to continue expanding our interstate storage facilities at Mist, Oregon. In order to adequately complete the studies necessary for the next storage project at Mist, we are delaying the timeline for this expansion but will continue to move forward with planning. We believe the earliest timeframe for beginning to move forward with construction efforts is 2011 or 2012. We have not determined the targeted construction schedule or in-service date at this time. Our current cost estimate for the next Mist expansion, assuming no change in project scope, remains between $45 million and $55 million, which includes the development of storage wells, a second compression station and a pipeline gathering system at Mist that will enable future storage expansions

Pipeline Diversification. Currently, our utility and gas storage at Mist depend on a single bi-directional interstate pipeline to ship gas supplies. Palomar Gas Transmission, LLC, a wholly-owned subsidiary of Palomar Gas Holdings, LLC, (PGH), is seeking to build a new gas transmission pipeline that would provide a new interconnection with our utility distribution system. PGH is owned 50 percent by NW Natural and 50 percent by Gas Transmission Corporation (GTN), an indirect wholly-owned subsidiary of TransCanada Corporation. The proposed Palomar pipeline is designed to serve our utility and the growing natural gas markets in Oregon and other parts of the western United States. The Palomar pipeline would be regulated by the Federal Energy Regulatory Commission (FERC). In December 2008, Palomar filed for a Certificate of Public Convenience and Necessity with the FERC.

As originally proposed, the Palomar pipeline included an east and west segment. The east segment would extend approximately 111 miles west from an interconnection with GTN’s existing interstate transmission mainline near Maupin, Oregon to an interconnection with NW Natural’s gas distribution system near Molalla, Oregon. The west segment would then extend approximately 106 miles further west to other potential additional interconnections including a possible connection to one of the two liquefied natural gas (LNG) terminals proposed to be built on the Columbia River. The east segment would not only diversify NW Natural’s gas delivery options and enhance the reliability of service to our utility customers by providing an alternate transportation path for gas purchases from different regions in western Canada and the U.S. Rocky Mountains, but also provide potential access to other shippers in the region. The west segment of Palomar was intended to provide the region, as well as our utility customers, with potential access to a new source of gas supply if an LNG terminal is built on the Columbia River.

On May 5, 2010, we learned that the shipper that had proposed to build an LNG terminal on the Columbia River had suspended its plans and filed for bankruptcy. Palomar had previously entered into a precedent agreement with that shipper for a majority of the pipeline capacity. PGH is currently evaluating the status of the precedent agreement with that shipper, and PGH and NW Natural are evaluating the impact of such shipper’s action on the development of the Palomar project. Although the full impact cannot be determined at this time, NW Natural expects that PGH will reconsider whether to proceed with the development of the pipeline's west segment. PGH continues to believe that the pipeline's east segment is commercially viable. See Note 11

Palomar will continue to focus on permitting activities during 2010, and we believe the FERC will issue a draft Environmental Impact Statement later this year or early next year. The date for when Palomar is expected to go into service will be impacted by the timing of our final FERC permit and the needs of shippers. See "Financial Condition—Cash Flows—Investing Activities," below for further discussion on the status of Palomar.

Consolidated Earnings and Dividends

For the three months ended March 31, 2010, we had net income of $43.6 million, or $1.64 per share, compared to net income of $47.4 million, or $1.78 per share, for the same period last year.

The primary factors contributing to the $3.8 million decrease in net income were:

- an $8.2 million decrease in utility net operating revenues (margin) from our regulatory share of gas cost savings;
- a $2.8 million decrease in utility margin from lower sales volumes to residential and commercial customers due to warmer weather and customer conservation, after adjustments for decoupling and weather mechanisms;

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- a $1.1 million increase in interest charges reflecting higher balances of long-term debt outstanding; and
- a $0.5 million decrease in utility margin from a regulatory adjustment for income taxes paid versus collected in rates.

Partially offsetting the above factors were:

- a $7.1 million increase in income from a refund of property taxes, reflecting a $5.2 million decrease to general taxes and $1.9 million increase to interest income;
- a $3.3 million decrease in operation and maintenance expense primarily due to lower employee compensation related to reduced number of employees, partially offset by higher consulting and legal fees of $1.0 million related to our refund of property taxes; and
- a $0.9 million increase in margin from gas storage operations.

Dividends paid on our common stock were 41.5 cents per share in the first quarter of 2010, compared to 39.5 cents per share in the first quarter of 2009. In April 2010, the Board of Directors declared a quarterly dividend on our common stock of 41.5 cents per share, payable on May 14, 2010 to shareholders of record on April 30, 2010. The current indicated annual dividend rate is $1.66 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 changes to the information provided in the 2009 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 2009 Form 10-K). 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. For a description of recent accounting pronouncements that could have an impact on our financial condition, results of operations or cash flows, see Note 1.

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, the 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 2009, 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, and 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 2009 Form 10-K.

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Rate Mechanisms

Purchased Gas Adjustment. Rate changes are established each year under PGA mechanisms in Oregon and Washington to reflect changes in the expected cost of natural gas commodity purchases, including gas storage, gas purchases hedged with financial derivatives, interstate pipeline demand charges, 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 2009, the OPUC and WUTC approved rate changes effective on November 1, 2009 under our PGA mechanisms. The effect of the rate changes was to decrease the average monthly bills of Oregon residential customers by 18 percent, partially offset by an increase in the public purpose charge, which resulted in a net decrease of 16 percent. The average monthly bills of Washington residential customers decreased by 22 percent.

Under the current Oregon PGA incentive sharing mechanism, we are required to select by August 1 of each year either an 80 percent deferral or 90 percent deferral of higher or lower actual gas costs compared to PGA prices such that the impact on current earnings from the gas cost incentive sharing is either 20 percent or 10 percent, respectively. In addition to the gas cost incentive sharing mechanism, we are also subject to an annual earnings review to determine if the utility is earning over an allowed return on equity (ROE) threshold. If utility earnings exceed a specific ROE threshold level, then 33 percent of the amount above the threshold will 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 80 percent deferral option for the 2008-2009 PGA year. In August 2009, we selected 90 percent deferral for the 2009-2010 PGA year. The ROE threshold is subject to adjustment up or down depending on movements in long-term interest rates. In 2009 and 2008, the ROE threshold after adjustment for long-term interest rates was 11.5 percent and 13.1 percent, respectively. No amounts were required to be refunded to customers as a result of the 2008 utility earnings review, and we do not expect that any amounts will be required to be refunded to customers as a result of the 2009 earnings review, which will be approved by the OPUC during the second quarter of 2010.

There has been no change to the Washington PGA mechanism under which we defer 100 percent of the higher or lower actual purchased gas costs and pass that difference through to customers as an adjustment to future rates. We do not have an earnings 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 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. These authorizations have been extended through January 2011. See Note 10.

Pension Deferral. We are currently subject to a regulatory deferral order from the OPUC whereby we must refund cost savings to customers when our annual pension expense is below the amount set for rate recovery in our last general rate case. However, we are currently not authorized to defer and recover any cost increases from customers when our annual pension expense is above the amount set in rates. For 2010, our operations and maintenance expense for pension is expected to be between $3 million and $4 million above the amount set in rates. In March 2010, we filed a request for authorization to defer pension expenses above the amount set in rates, and to recover the amount through future rate increases or through a balancing account mechanism that would include the effects of anticipated lower pension expenses in future years.

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Business Segments - Utility Operations

Our utility margin results are affected by customer growth and to a certain extent by changes in weather and customer consumption 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 revenues to offset changes in margin resulting from increases or decreases in residential and commercial customer consumption. We also have a weather normalization mechanism that adjusts customer bills up or down to offset changes in margin resulting from above- or below-average temperatures during the winter heating season (see Part II, Item 7., "Results of Operations—Regulatory Matters—Rate Mechanisms," in the 2009 Form 10-K). Both mechanisms are designed to reduce the volatility of our utility earnings.

Our utility segment reported net income of $40.9 million, or $1.54 per share, in the first quarter of 2010 compared to $45.3 million, or $1.70 per share, in the first quarter of 2009. The most significant factor contributing to the $4.4 million decrease in earnings was a reduction in margin gains from our regulatory share of gas cost savings. Total utility margin decreased $12.6 million, including an $8.2 million decrease from our share of lower gas costs. In addition, residential and commercial margin declined $2.8 million, including the effects of the weather normalization and decoupling mechanisms, and industrial margin declined $0.3 million. Total volumes were down 19 percent from a year ago reflecting 19 percent warmer weather and declining use per customer.

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

Thousands, except degree day and customer data	Three months ended March 31, 2010	2009	Favorable/ (Unfavorable)
Utility volumes - therms:			
Residential sales	133,860	178,389	(44,529)
Commercial sales	78,856	103,117	(24,261)
Industrial - firm sales	10,153	12,037	(1,884)
Industrial - firm transportation	32,611	35,401	(2,790)
Industrial - interruptible sales	16,324	22,899	(6,575)
Industrial - interruptible transportation	61,599	59,467	2,132
Total utility volumes sold and delivered	333,403	411,310	(77,907)
Utility operating revenues - dollars:			
Residential sales	$ 169,609	$ 253,057	$ (83,448)
Commercial sales	80,075	129,350	(49,275)
Industrial - firm sales	8,618	13,704	(5,086)
Industrial - firm transportation	1,436	1,402	34
Industrial - interruptible sales	10,381	21,939	(11,558)
Industrial - interruptible transportation	1,919	1,922	(3)
Regulatory adjustment for income taxes paid (1)	2,984	3,513	(529)
Other revenues	6,041	7,913	(1,872)
Total utility operating revenues	281,063	432,800	(151,737)
Cost of gas sold	148,548	284,164	135,616
Revenue taxes	7,042	10,542	3,500
Utility margin	$ 125,473	$ 138,094	$ (12,621)
Utility margin: (2)			
Residential sales	$ 66,404	$ 86,333	$ (19,929)
Commercial sales	25,708	33,774	(8,066)
Industrial - sales and transportation	7,123	7,422	(299)
Miscellaneous revenues	1,673	1,892	(219)
Gain (loss) from gas cost incentive sharing	199	8,432	(8,233)
Other margin adjustments	(19)	498	(517)
Margin before regulatory adjustments	101,088	138,351	(37,263)
Weather normalization adjustment	13,535	(8,714)	22,249
Decoupling adjustment	7,866	4,944	2,922
Regulatory adjustment for income taxes paid (1)	2,984	3,513	(529)
Utility margin	$ 125,473	$ 138,094	$ (12,621)
Customers - end of period:			
Residential customers	606,935	601,917	5,018
Commercial customers	62,477	62,541	(64)
Industrial customers	917	929	(12)
Total number of customers - end of period	670,329	665,387	4,942
Actual degree days	1,627	2,021	
Percent colder (warmer) than average (3)	(13%)	8%	

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

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Residential and Commercial Sales

Residential and commercial sales are impacted by 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 annual utility operating revenues 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 due to our weather normalization mechanism in Oregon where about 90 percent of our customers are served. This mechanism is in effect for the period from December 1 through May 15 of each heating season, but customers are allowed to opt out of the mechanism. For the current gas year approximately 9 percent of our Oregon residential and commercial customers have opted out of the mechanism, which is fairly consistent with prior years. In Oregon, we also have a conservation decoupling mechanism that is intended to break the link between our earnings and the quantity of gas consumed by customers, so that we do not have an incentive to encourage greater consumption and undermine Oregon's conservation policy and efforts. In Washington, where the remaining 10 percent of our customers are served, we do not have a weather normalization or a conservation decoupling mechanism. As a result, we are not fully insulated from earnings volatility due to weather and conservation in Washington.

The primary factors that impact first quarter results of operations in the residential and commercial markets are customer growth, seasonal weather patterns, competition from other energy sources, economic conditions and, to a certain extent, the volatility of gas prices:

- utility operating revenues decreased $132.7 million or 35 percent primarily due to PGA rate decreases for lower gas prices effective November 1, 2009, with average residential and commercial rates decreasing 18 percent and 22 percent in Oregon and Washington, respectively;
- volumes decreased 24 percent primarily reflecting 19 percent warmer weather, customer conservation and weak economic conditions partially offset by a customer growth rate of 0.7 percent; and
- margin decreased $2.8 million or 2 percent including the effects of weather normalization and decoupling adjustments.

Utility operating revenues include accruals for unbilled revenues based on estimates of gas deliveries from that month's meter reading dates to month end. Weather conditions, rate changes and customer billing dates affect the balance of accrued unbilled revenues at the end of each month. At March 31, 2010, accrued unbilled revenue was $39.2 million, compared to $61.0 million at March 31, 2009, with the 36 percent decrease primarily due to the lower billing rates mentioned above and lower volumes.

Industrial Sales and Transportation

Industrial operating revenues include the commodity cost component of gas sold under sales service but not under transportation service. Therefore, industrial customer switching between sales service and transportation service can cause swings in utility operating revenues but generally our margins are unaffected because we do not mark up the cost of gas.

The primary factors that impacted first quarter results of operations from industrial sales and transportation services were as follows:

- volumes delivered decreased 9.1 million therms, or 7 percent, reflecting reduced usage primarily due to weak economic conditions; and
-

margin decreased $0.3 million, or 4 percent, also reflecting the weak economy and lower volumes, which were partly mitigated by mostly fixed cost recovery rate design for some of the larger customers.

Regulatory Adjustment for Income Taxes Paid

Oregon law requires 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 than we collect from our Oregon utility customers, or if our consolidated taxes paid are less than the taxes we collect from our Oregon utility customers, then we are required to refund the excess to our Oregon utility customers. Conversely, if we pay more income taxes than we actually collect from our Oregon utility customers, as calculated using rate increments from our most recent general rate case, then we are required to collect a surcharge from our Oregon utility customers.

For the three months ended March 31, 2010, we recognized $3.0 million of pre-tax income representing a difference of $2.9 million of estimated federal and state income taxes paid in excess of taxes collected in rates (surcharge) plus accrued interest of $0.1 million attributed to the 2008 and 2009 tax years. For the three months ended March 31, 2009, we recognized a surcharge of $3.5 million, which included accrued interest of $0.2 million attributed to the 2007 and 2008 tax years.

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Other Revenues

Other revenues include miscellaneous fee income and revenue adjustments reflecting deferrals to, or amortizations from, regulatory asset or liability accounts other than deferred gas costs. Other revenues were $6.0 million in the first quarter of 2010, a decrease of $1.9 million over the first quarter of 2009, due to a net decrease in the deferral and amortization for the decoupling adjustment. Although other regulatory deferral collections, refunds and amortizations can have a material impact on utility operating revenues, they generally do not have a material impact on margin because they are offset by increases or decreases in customer sales rates.

Cost of Gas Sold

The cost of gas sold includes current gas purchases, gas drawn from storage inventory, gains and losses from commodity hedges, pipeline demand charges, 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 the WUTC require natural gas commodity costs 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 is affected by differences between actual and expected purchased gas costs due to market fluctuations and volatility affecting unhedged purchases. We use natural gas 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 financial hedge contracts are generally included in our PGA prices and normally do not impact net income as the hedges are usually 100 percent passed through to customers in annual rate changes, subject to a regulatory prudency review. However, utility gas hedges entered into after the annual PGA filing in Oregon, if any, may impact net income to the extent of our share of any gain or loss under the PGA. In Washington, 100 percent of the actual gas costs, including all hedge gains and losses, 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 2009 Form 10-K, and Note 10 in this report). For the three months ended March 31, 2010:

- total cost of gas sold decreased $135.6 million or 48 percent, due to lower gas prices and lower sales volumes, which were driven by weather that was 19 percent warmer than last year, customer conservation and a weak economy;
- the average gas cost collected through rates decreased 31 percent from 90 cents per therm in 2009 to 62 cents per therm in 2010, primarily reflecting lower market prices that were passed through to customers through PGA rates effective November 1, 2009 and increased spot gas purchases at lower price levels than assumed in the PGA; and
- realized hedge losses totaling $6.2 million were included in cost of gas this quarter, compared to $79.3 million in the first quarter of 2009.

Our gas cost incentive sharing mechanism resulted in a margin gain of $0.2 million in the first quarter of 2010, compared to a margin gain of $8.4 million in the first quarter of 2009.

Business Segments Other than Utility Operations

Gas Storage

Operating results at our gas storage segment currently consist of the non-utility portion of our Mist underground storage facility, utility and non-utility asset optimization and start-up costs at Gill Ranch (see Part I, Item 1., "Business Segments—Gas Storage," in our 2009 Form 10-K). For the three months ended March 31, 2010, net income from gas storage was $2.5 million, or 9 cents per share, compared to $2.0 million, or 8 cents per share, for the same period in 2009. The $0.5 million increase in earnings over 2009 is primarily due to increased revenues from optimization services.

In Oregon, we retain 80 percent of the pre-tax income from Mist gas storage services as well as from optimization services when the costs of the capacity being used are not included in utility rates, or 33 percent of the pre-tax income from such storage and optimization services when the capacity being used is included in utility rates.

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The remaining 20 percent and 67 percent, respectively, are credited to a deferred regulatory account for refund to our core utility customers. We have a similar sharing mechanism in Washington for pre-tax income derived from gas storage and optimization services.

In 2007, we announced a joint project with PG&E to develop a new underground natural gas storage facility at Gill Ranch near Fresno, California. Our subsidiary Gill Ranch is developing and will operate the facility. We own 75 percent of the project, and PG&E owns 25 percent. As of March 31, 2010 and 2009, our construction investment balance in Gill Ranch was $106.6 million and $13.7 million, respectively. See Note 2 in the 2009 Form 10-K.

Other

Our other business segment consists of Financial Corporation, an equity investment in Palomar and other non-utility investments and business activities. Financial Corporation had total assets at March 31, 2010 and 2009 of $1.2 million and $1.3 million, respectively, reflecting a non-controlling interest in the Kelso-Beaver pipeline. Our equity investment balance in Palomar was $14.5 million and $15.5 million, respectively, reflecting our equity investment to date in a proposed transmission pipeline. For more information on Palomar, see Notes 2 and 11.

Net income from our other business segment for the first quarter of 2010 and 2009 was $0.2 million and less than $0.1 million, respectively. See Note 2.

Consolidated Operating Expenses

Operations and Maintenance

Operations and maintenance expense was $30.7 million in 2010 compared to $34.0 million in 2009, a decrease of $3.3 million or 10 percent. The primary factors contributing to the decrease in operations and maintenance expense were:

- a $4.3 million decrease in employee compensation expense related to reduced number of employees and lower bonus accruals; and
- a $1.3 million decrease in utility bad debt expense primarily due to lower revenues (see discussion below).

Partially offsetting the above decreases were:

- a $1.0 million increase in consulting and legal fees related to our property tax appeal and favorable Oregon Supreme Court ruling; and
- a $1.0 million increase in health care premiums.

Our bad debt expense as a percent of revenues was 0.36 percent for the three months ended March 31, 2010 compared to 0.42 percent for the year ended December 31, 2009. Credit activity has stabilized but continues to carry slightly higher delinquent balances due to the weak economy and high unemployment rates. Lower customer usage from warmer than normal weather and customer conservation, plus more low income energy assistance funds available for customers, has helped mitigate our credit exposure. Also, we have a rate mechanism that covers the increase (or decrease) in bad debt expense directly related to increases (or decreases) in commodity costs. Under our PGA mechanism, billing rates are adjusted each year to recover the expected increase (or decrease) in bad debt expense due to the higher (or lower) cost of natural gas.

General Taxes

General taxes, which are principally comprised of property taxes, payroll taxes and regulatory fees, decreased $5.2 million in the three months ended March 31, 2010 over the same period in 2009. This decrease was due to our property tax refund resulting from successful litigation with the Oregon Department of Revenue.

We were involved in litigation with the Oregon Department of Revenue over whether inventories held for sale are required to be taxed as personal property. In January 2010, the Oregon Supreme Court unanimously ruled in our favor, stating that these inventories are exempt from property tax. As a result of this ruling, we were entitled to a refund of approximately $5.2 million, plus accrued interest, for property 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 paid; $1.9 million for accrued interest income; and $1.0 million of increased operations and maintenance expense for legal and consulting services. As of April 30, 2010, we have received $7.0 million of the $7.1 million recognized, and we expect to collect the remainder by the end of the second quarter of 2010.

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Depreciation and Amortization

Total depreciation and amortization expense increased by $0.4 million, or 2 percent for the three months ended March 31, 2010, compared to the same period in 2009. This increase reflects added utility plant from customer growth and other capital project expenditures.

Other Income and Expense – Net

The following table summarizes other income and expense – net by primary components:

Thousands	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Other income and expense - net:		
Gains from company-owned life insurance	$396	$1,081
Interest income	1,910	60
Income from equity investments	316	288
Net interest on deferred regulatory accounts	991	501
Other	(590)	(1,040)
Total other income and expense - net	$3,023	$890

Other income and expense – net increased $2.1 million, primarily due to $1.9 million in interest income related to the property tax refund discussed under "General Taxes," above.

Interest Charges – Net of Amounts Capitalized

Interest charges – net of amounts capitalized increased $1.1 million, or 12 percent, in the three months ended March 31, 2010 compared to the same period in 2009, reflecting the issuance of long-term debt in 2009 at rates that were higher than the short-term debt balances redeemed. The issuances included $75 million of 5.37 percent medium-term notes (MTNs) in March 2009 and $50 million of 3.95 percent MTN's in July 2009.

Income Tax Expense

Income tax expense totaled $30.0 million in the three months ended March 31, 2010 compared to $28.8 million in the three months ended March 31, 2009. The higher income tax expense reflected an increase in the Oregon corporate income tax rate, from 6.6 percent to 7.9 percent (see "Consolidated Operations—Income Tax Expense," in the 2009 Form 10-K), and an increase in the amortization of our regulatory tax asset account on pre-1981 plant assets (see "Regulatory Matters—Rate Mechanisms—Depreciation Study," in the 2009 Form 10-K). The effective tax rate for the first quarter of 2010 was 40.8 percent, compared to 37.8 percent for the first quarter of 2009. See Note 7.

On March 23, 2010 the Patient Protection and Affordable Care Act (the PPACA) was signed into law and on March 30, 2010 the Health Care and Education Reconciliation Act of 2010 was signed into law, which makes various amendments to certain aspects of the PPACA. The PPACA changes the tax treatment of federal subsidies paid to sponsors of retiree health benefit plans that provide a benefit that is at least actuarially equivalent to the benefits under Medicare Part D. These subsidy payments become taxable in years beginning after December 31, 2012. Accounting guidance on income taxes requires the impact of this change in tax law to be immediately recognized in the period that includes the enactment date. This tax provision of the PPACA did not have, and is not expected to have, an impact on our financial condition, results of operations or cash flows as we do not receive federal subsidy payments under

Medicare Part D.

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Financial Condition

Capital Structure

Our goal 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. When additional capital is required, debt or equity securities are issued depending upon both the target capital structure and market conditions. These sources also are used to fund long-term debt redemption requirements and short-term commercial paper maturities (see "Liquidity and Capital Resources," below, and Note 5). 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 was as follows:

	March 31, 2010		March 31, 2009		Dec. 31, 2009	
Common stock equity	48.6	%	49.6	%	47.2	%
Long-term debt	42.2	%	43.8	%	43.0	%
Short-term debt, including current maturities of long-term debt	9.2	%	6.6	%	9.8	%
Total	100.0	%	100.0	%	100.0	%

Liquidity and Capital Resources

At March 31, 2010, we had $8.8 million of cash and cash equivalents compared to $10.3 million at March 31, 2009. We also had $40.9 million in restricted cash invested at Gill Ranch as of March 31, 2010, which is being held as collateral for equipment purchase contracts and construction loans. In order to maintain sufficient liquidity during recent periods of volatile capital markets, we maintained higher cash balances, added short-term borrowing capacity as needed, and pre-funded some utility capital expenditures while long-term fixed rate environments were attractive. 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 to finance capital expenditures, refinance maturing short-term or long-term debt and provide for general corporate purposes. In March 2009, we issued $75 million of secured MTNs with an interest rate of 5.37 percent and a maturity date of February 1, 2020. In July 2009, we issued $50 million of secured MTNs with an interest rate of 3.95 percent and a maturity date of July 15, 2014.

Our senior secured long-term debt ratings are AA- and A1 from Standard & Poor's (S&P) and Moody's Investors Service (Moody's), respectively. Our short-term debt ratings are A-1 from S&P and P-1 from Moody's. The capital markets in the last two years, including the commercial paper market, experienced significant volatility and tight credit conditions, but conditions over the past 12 months improved as reflected by tighter credit spreads and increased access to new financing for investment grade issuers. With our debt ratings, we have been able to issue commercial paper and MTNs at attractive rates and have not needed to borrow from our $250 million back-up facility. In the event that we are not able to issue new debt due to market conditions, we expect that our near term liquidity needs can be met by using cash balances or drawing upon our committed credit facility (see "Credit Agreement," below). We also have a universal shelf registration statement 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 statement. We expect to file a new shelf registration statement, as required, prior to January 8, 2011.

Our senior unsecured long-term debt ratings are A+ and A3 from S&P and Moody's, respectively. In the event that our senior unsecured long-term debt 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, 2010, we would be required to post approximately $23.1 million of collateral to our counterparties, but that would assume our long-term debt ratings were at non-investment grade levels, a level that is significantly lower than our current ratings.

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Based on several factors, including our current credit ratings, our recent experience issuing commercial paper, our current cash reserves, our committed credit facilities, other liquidity resources and our expected ability to issue long-term debt and equity securities 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, 2010, our purchase commitments remain relatively unchanged from December 31, 2009 (see "Financial Condition--Contractual Obligations," in the 2009 Form 10-K), except for a net increase of $29.4 million for purchase commitments in connection with the development of Gill Ranch.

Short-term Debt

Our primary source of short-term liquidity is from internal cash flows and the sale of commercial paper short- term debt. In addition to issuing commercial paper to meet seasonal working capital requirements, including the financing of gas inventories and accounts receivable, short-term debt may be used to temporarily fund 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 Agreement," 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 two years. At March 31, 2010 and 2009, our utility had commercial paper outstanding of $56.0 million and $82.8 million, respectively, and Gill Ranch had bank loans outstanding of $40.0 million and $5.8 million, respectively, under its $40 million cash collateralized credit facility.

Credit Agreement

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 under our credit agreement are major financial institutions with committed balances and investment grade credit ratings as of March 31, 2010 as follows:

Lender rating, by category		Amount Committed (in $000's)
AAA/Aaa	$	-
AA/Aa		230,000
A/A		20,000
BBB/Baa		-
Total	$	250,000

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

The loan commitments with all lenders under the syndicated credit agreement have been extended to May 31, 2013. The credit agreement 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 credit 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 owed on borrowings under the credit agreement is due and payable on or before the maturity date. There were no outstanding balances under this credit agreement at March 31, 2010 and 2009. The credit agreement also requires us to maintain a consolidated indebtedness to total capitalization ratio as determined in accordance with the credit agreement 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, 2010 and 2009.

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The syndicated credit agreement also requires that we maintain credit ratings with S&P and 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 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 agreement are tied to debt ratings, which would increase or decrease the cost of any loans under the credit agreement when ratings are changed (see "Credit Ratings," below).

Credit Ratings

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)	AA-	A1
Senior unsecured (long-term debt)	A+	A3
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.

Redemptions of Long-Term Debt

In November 2009, one investor in our 6.65 percent secured MTNs due 2027 exercised its right under a one-time put option to redeem $0.3 million of the $20 million outstanding. This one-time put option has now expired, and the remaining $19.7 million remaining principal outstanding is expected to be redeemed at maturity in November 2027. No redemptions occurred during the three month periods ended March 31, 2010 or 2009.

For long-term debt maturing over the next five years, see Part II, Item 7., "Results of Operations—Financial Condition—Contractual Obligations," in our 2009 Form 10-K.

Cash Flows

Operating Activities

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. In the three months ended March 31, 2010, cash flow from operating activities, excluding working capital changes, decreased $38.8 million compared to the same period in 2009. Cash flow from working capital changes in the three months ended March 31, 2010 decreased $33.9 million compared to the same period in 2009. The overall change in cash flow from operating activities was a decrease of $72.7 million. The significant factors contributing to changes in cash flow for the three months ended March 31, 2010 compared to the same period of 2009 are as follows:

- a decrease of $49.4 million in the balance of deferred gas costs savings, reflecting higher deferrals of gas cost savings in last year's first quarter and mid-year customer refunds in 2009 totaling $36 million;
- a decrease of $24.0 million from accounts payable balances, reflecting lower gas prices;

- a decrease of $10.0 million for the pension contribution in March 2010 to reduce our unfunded liability;
- a decrease of $19.0 million in income taxes receivable as refunds were received in 2009 for bonus depreciation and a net operating loss carryover from 2008;
- an increase of $10.1 million related to the 2009 settlement payment on our interest rate hedge; and
- a net increase of $13.7 million in deferred regulatory costs and other.

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In February 2009, the American Recovery and Reinvestment Act of 2009 (Act) was signed into law. This Act extended for another year the ability for businesses to take an additional first-year depreciation deduction equivalent to 50 percent of an asset's adjusted basis for qualified property purchased and placed in service during 2009. We estimate the bonus depreciation provision will defer the payment of approximately $13.0 million of federal income taxes during 2010 to future periods.

Investing Activities

Cash used in investing activities for the three months ended March 31, 2010 totaled $57.4 million, up from $34.1 million for the same period in 2009. Cash requirements for the acquisition and construction of utility plant were $17.0 million in the three months ended March 31, 2010, down $4.6 million from $21.6 million for the same period in 2009.

Cash requirements for investments in non-utility property were $35.8 million in the three months ended March 31, 2010, primarily related to investments in Gill Ranch, compared to $6.2 million in 2009. We started construction of Gill Ranch facilities in January 2010.

In 2010, utility capital expenditures are estimated to be between $80 and $90 million, and non-utility capital investments are expected to be between $120 million and $145 million for business development projects that are currently in process (see "Strategic Opportunities," above).

Over the five-year period 2010 through 2014, utility capital expenditures are estimated at between $400 million and $500 million, reflecting customer growth, technology improvements and utility system improvements, including requirements under the Pipeline Safety Improvement Act of 2002. Most of the required funds are expected to be internally generated over the five-year period and any remaining funding will be obtained through the issuance of long-term debt or equity securities, with short-term debt providing liquidity and bridge financing (see Part II, Item 7., "Financial Condition—Cash Flows—Investing Activities," in the 2009 Form 10-K).

Our funding of the total cost for the current development at Gill Ranch project is estimated to be between $185 million and $205 million. As of March 31 2010, we have invested $93.6 million of equity funds in Gill Ranch. The remaining project cost is expected to be met from a combination of equity funds and debt, which will be non-recourse to NW Natural. We have not pledged any of our utility assets, nor have we provided any parent guarantees, toward Gill Ranch's obligations.

In 2010, Palomar will continue to work on the planning and permitting phase of the pipeline project. The total cost for planning and permitting, excluding credit support, is estimated to be between $40 million and $50 million, of which our ownership interest is 50 percent. As of March 31, 2010, we had a net equity investment of $14.5 million in this project. The initial planning and permitting costs will be financed with equity funds from us and our partner, GTN. Palomar had executed precedent agreements whereby a significant majority of the pipeline capacity was committed to the shipper which had planned to build an LNG terminal on the Columbia River. That shipper filed for bankruptcy on May 5, 2010. See "Strategic Opportunities—Pipeline Diversification," above and Note 11.

In April 2009, Palomar received $15.8 million of cash proceeds which had supported the majority shipper's obligations under a prior agreement. These cash proceeds received were applied against Palomar project costs. Additionally, the shipper provided additional collateral to secure its obligations under the precedent agreement and support a portion of the ongoing planning and permitting costs as the project developed. Palomar is in the process of determining the appropriate next steps with respect to its contract rights and the collateral.

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As a result of the majority shipper's suspension of operations and petition for bankruptcy, we are currently re-evaluating the scope and total cost of the Palomar project. However, based on an ongoing review of the Palomar pipeline project and the interest expressed by other potential shippers, PGH believes that the piepline's east segment of the Palomar project is still commercially viable. PGH has a binding precedent agreement with our own utility, which represents a minority of the current design capacity on the pipeline. PGH has been discussing precedent agreements with other potential shippers for the pipeline's east segment. We will continue to manage project risks, evaluate project costs and assess the fair value of our investment on a quarterly basis, including an updated evaluation of the collateral provided by the shipper which had planned to build the LNG terminal on the Columbia River. Additionally, PGH will continue to evaluate market conditions and project status to determine if and when to proceed with construction of all or some portion of the project. See Note 11, above, and Part I, Item 1A., "Risk Factors," in the 2009 Form 10-K.

Financing Activities

Cash used in financing activities in the three months ended March 31, 2010 totaled $16.4 million, as compared to cash used of $109.4 million for the same period in 2009. The decrease of $93.0 million was due to a significant reduction in short-term debt in 2009, partially offset by long-term debt issuance totaling $75 million in 2009. We use long-term debt proceeds primarily to finance capital expenditures, refinance maturing short-term or redeem long-term debt maturities as well as for general corporate purposes.

Pension Funding Status

We make contributions to company-sponsored qualified defined benefit pension plans based on actuarial assumptions and estimates, tax regulations and funding requirements under federal law. Our qualified defined benefit pension plans are currently underfunded by $83.9 million at December 31, 2009. In March 2010, we contributed $10 million to these plans, with a portion allocated to 2009 and 2010 plan years. For more information on the funding status of our qualified retirement plans and other postretirement benefits, see Note 7, and Part II, Item 7., "Financial Condition—Pension Cost and Funding Status of Qualified Retirement Plans," and Part II, Item 8., Note 7, "Pension and Other Postretirement Benefits," in the 2009 Form 10-K.

We also contribute to a multiemployer pension plan (Western States Plan) pursuant to our collective bargaining agreement. Our total contribution to the Western States Plan in 2009 amounted to $0.4 million. We made contributions totaling $0.1 million to the Western States Plan for the three months ended March 31, 2010 and 2009. See Note 6 for further discussion.

Ratios of Earnings to Fixed Charges

For the three and twelve months ended March 31, 2010 and the twelve months ended December 31, 2009, our ratios of earnings to fixed charges, computed using the Securities and Exchange Commission method, were 7.71, 3.73 and 3.86, 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 the 2009 Form 10-K). At March 31, 2010, a cumulative $107.5 million in environmental costs was recorded as a regulatory asset, consisting of $39.3 million of costs paid to date, $57.7 million for additional environmental accruals for costs expected to be paid in the future and accrued regulatory interest of $10.5 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 10.

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Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to various forms of market risk including, but not limited to, commodity supply risk, commodity price risk, interest rate risk, foreign currency risk, credit risk and weather risk (see Part I, Item 1A., "Risk Factors," and Part II, Item 7A. "Quantitative and Qualitative Disclosures about Market Risk," in the 2009 Form 10-K). The following are updates to certain of these market risks:

Commodity Price Risk

Natural gas commodity prices are subject to fluctuations due to unpredictable factors including weather, pipeline transportation congestion, potential market speculation and other factors that affect short-term supply and demand. Commodity-price financial swap and option contracts (financial hedge contracts) are used to convert certain natural gas supply contracts from floating prices to fixed or capped prices. These financial hedge contracts are generally included in our annual PGA filing for recovery, subject to a regulatory prudence review. At March 31, 2010 and 2009, notional amounts under these financial hedge contracts totaled $288.2 million and $281.9 million, respectively. If all of the commodity-based financial hedge contracts had been settled on March 31, 2010, a loss of $57.4 million would have been realized and recorded to a deferred regulatory account (see Note 10). We regularly monitor the liquidity of our financial hedge contracts. Based on the existing open interest in the contracts held, we believe existing contracts to be liquid. All of our current outstanding financial hedge contracts will settle on or before October 31, 2012. The $57.4 million unrealized loss is an estimate of future cash flows based on forward market prices that are expected to be paid as follows: $38.9 million in the next 12 months and $18.5 million thereafter. The amount realized will change based on market prices at the time contract settlements are fixed.

Credit Risk

Credit exposure to suppliers. Certain suppliers that sell us gas have either relatively low credit ratings or are not rated by major credit rating agencies. To manage this supply risk, we purchase gas from a number of different suppliers at liquid exchange points. We evaluate and monitor suppliers' creditworthiness and maintain the ability to require additional financial assurances, including deposits, letters of credit or surety bonds, in case a supplier defaults. In the event of a supplier's failure to deliver contracted volumes of gas, the regulated utility would need to replace those volumes at prevailing market prices, which may be higher or lower than the original transaction prices. We believe these costs would be subject to the PGA sharing mechanism discussed above. Since most of our commodity supply contracts are priced at the monthly market index price tied to liquid exchange points, and we have significant storage flexibility, we believe that it is unlikely that a supplier default would have a material adverse effect on our financial condition or results of operations.

Credit exposure to financial derivative counterparties. Based on estimated fair value at March 31, 2010, our overall credit exposure relating to commodity hedge contracts reflects an amount owed to our financial derivative counterparties of $57.4 million. Our financial derivatives policy requires counterparties to have at least an investment-grade credit rating at the time the derivative instrument is entered into, and specific limits on the contract amount and duration based on each counterparty's credit rating. Due to current market conditions and credit concerns, we continue to enforce strong credit requirements. We actively monitor and manage our derivative credit exposure and place counterparties on hold for trading purposes or require cash collateral, letters of credit or guarantees as circumstances warrant. Our actual derivative credit risk exposure, which reflects amounts that financial derivative counterparties owe to us, is less than $0.1 million, and these amounts are under contracts that are expected to settle on or before October 31, 2012.

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The following table summarizes our overall credit exposure, based on estimated fair value, and the corresponding counterparty unsecured credit ratings. The table uses credit ratings from S&P and Moody's, reflecting the higher of the S&P or Moody's rating or a middle rating if the entity is split-rated with more than one rating level difference:

	Financial Derivative Position by Credit Rating Unrealized Fair Value Gain (Loss)		
Thousands	March 31, 2010	March 31, 2009	Dec. 31, 2009
AAA/Aaa	$ -	$ (9,246)	$ -
AA/Aa	(57,246)	(101,516)	(15,792)
A/A	(153)	(5,531)	-
BBB/Baa	-	-	-
Total	$ (57,399)	$ (116,293)	$ (15,792)

To mitigate the credit risk of financial derivatives we have master netting arrangements with our counterparties that provide for making or receiving net cash settlements. Generally, transactions of the same type in the same currency that have a settlement on the same day with a single counterparty are netted and a single payment is delivered or received depending on which party is due funds.

Additionally we have master contracts in place with each of our derivative counterparties that include provisions for posting or calling for collateral. Generally we can obtain cash or marketable securities as collateral with one day's notice. We use various collateral management strategies to reduce liquidity risk. The collateral provisions vary by counterparty but are not expected to result in the significant posting of collateral, if any. We have performed stress tests on the portfolio and concluded that the liquidity risk from collateral calls is not material. Our derivative credit exposure is primarily with investment grade counterparties rated AA-/Aa3 or higher. Contracts are diversified across counterparties to reduce credit and liquidity risk

Item 4. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

Our management, 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

Our management 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, 2010 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).

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PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

Litigation

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, we do not expect that the ultimate disposition of any of these matters will have a material adverse effect on our financial condition, results of operations or cash flows. For a discussion of certain pending legal proceedings, see Note 11.

Item 1A. RISK FACTORS

There were no material changes from the risk factors discussed in Part I, "Item 1A. Risk Factors," in our 2009 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 2009 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, 2010 of equity securities that are registered pursuant to Section 12 of the Exchange Act:

ISSUER PURCHASES 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
01/01/10 - 01/31/10	1,182	$43.64	-	-
02/01/10 - 02/28/10	22,025	$42.79	-	-
03/01/10 - 03/31/10	16,744	$46.06	-	-
Total	39,951	$44.18	2,124,528	$ 16,732,648

(1) During the three months ended March 31, 2010, 23,347 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, 16,604 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 three months ended March 31, 2010, 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 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 31, 2010 to repurchase up to an aggregate of 2.8 million shares or up to an aggregate of $100 million. During the three months

ended March 31, 2010, no shares of our common stock were purchased pursuant to this program. Since the program's inception in 2000 we have repurchased 2.1 million shares of common stock at a total cost of $83.3 million.

Item 6. EXHIBITS

See Exhibit Index attached hereto.

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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 6, 2010

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

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NORTHWEST NATURAL GAS COMPANY

EXHIBIT INDEX
To
Quarterly Report on Form 10-Q
For Quarter Ended
March 31, 2010

Document	Exhibit Number
Computation of Ratio of Earnings to Fixed Charges	12
Certification of Principal Executive Officer Pursuant to Rule 13a-14(a)/15d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002	31.1
Certification of Principal Financial Officer Pursuant to Rule 13a-14(a)/15d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002	31.2
Certification of Principal Executive Officer and Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	32.1