NORTHWEST NATURAL GAS CO
Form 10-Q
May 04, 2009

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, 2009

OR

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

For the Transition period from _______ to _______
Commission File No. 1-15973

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

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [X] No [ ]

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T 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.

Large accelerated filer [X]	Accelerated filer [ ]
Non-accelerated filer [ ]	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, 2009, 26,504,188 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, 2009

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Forward-Looking Statements

Statements and information included in this report that are not purely historical are forward-looking statements within the "safe harbor" provisions and meaning of Section 21E of the Securities Exchange Act of 1934, as amended (Exchange Act). Forward-looking statements include any statement other than a statement of purely historical fact, but are not limited to, statements concerning plans, objectives, goals, business and financial strategies, future events or performance or operational efficiencies, trends, cyclicality and the seasonality of our business, growth, capitalization, company ratings, development of projects, future cost of gas or our ability to manage such costs, gains or losses from our share of gas costs that are less than or more than the gas costs embedded in customer rates, exploration of new gas supplies, estimated expenditures, budgets, capital and construction costs, and future cash flows, costs of compliance, impact of accounting policies and standards, potential efficiencies, impacts of new laws and regulations, projected obligations and liabilities under retirement plans, adequacy of and shift in mix of gas supplies, and adequacy of accruals and regulatory deferrals. Such statements are expressed in good faith and we believe have a reasonable basis; however, each forward-looking statement involves uncertainties and is qualified in its entirety by reference to the following important factors, among others, that could cause our actual results to differ materially from those projected, including:

- prevailing state and federal governmental policies and regulatory actions with respect to allowed rates of return, industry and rate structure, timely and adequate regulatory recovery of deferred costs, including, but not limited to, purchased gas cost and investment recovery, acquisitions and dispositions of assets and facilities, operation and construction of plant facilities, present or prospective wholesale and retail competition, changes in laws and regulations including but not limited to tax laws and policies, changes in and compliance with environmental and safety laws, regulations, policies and orders, and laws, regulations and orders with respect to the maintenance of pipeline integrity, including regulatory allowance or disallowance of costs based on regulatory prudency reviews;

- economic factors that could cause a severe downturn in the national economy, in particular the economies of Oregon and Washington, thus affecting demand for natural gas;

- unanticipated customer growth or decline and changes in market demand caused by changes in demographic or customer consumption patterns;

- the creditworthiness of customers, suppliers and financial derivative counterparties;

- market conditions and pricing of natural gas relative to other energy sources;

- sufficiency of our liquidity position and unanticipated changes that may affect our liquidity or access to capital markets, including volatility in the credit environment and financial services sector;

- capital market conditions, including their effect on financing costs, the fair value of pension assets and on pension and other postretirement benefit costs;

- application of the Oregon Public Utility Commission rules interpreting Oregon legislation intended to ensure that utilities do not collect more income taxes in rates than they actually pay to government entities;

- weather conditions, natural phenomena including earthquakes or other geohazard events, and other pandemic events;

- competition for retail and wholesale customers and our ability to remain price competitive;

- our ability to access sufficient gas supplies and our dependence on a single pipeline transportation company for natural gas transmission;
- property damage associated with a pipeline safety incident, as well as risks resulting from uninsured damage to our property, intentional or otherwise;
- financial and operational risks , estimates and projections relating to business development and investment activities, including the Gill Ranch underground gas storage facility and Palomar pipeline;

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- unanticipated changes in interest rates, foreign currency exchange rates or in rates of inflation;
- changes in estimates of potential liabilities relating to environmental contingencies or in timely and adequate regulatory or insurance recovery for such liabilities;
- unanticipated changes in future liabilities and legislation relating to employee benefit plans, including changes in key assumptions;
- our ability to transfer knowledge of our aging workforce and maintain a satisfactory relationship with the union that represents a majority of our workers;
- potential inability to obtain permits, rights of way, easements, leases or other interests or other necessary authority to construct pipelines, develop storage or complete other system expansions and the timing of such projects;
- federal, state or other regulatory actions related to climate change; and
- legal and administrative proceedings and settlements.

These forward-looking statements involve risks and uncertainties. We may make other forward-looking statements from time to time, including statements in press releases and public conference calls and webcasts. All forward-looking statements made by us are based on information available to us at the time the statements are made and speak only as of the date on which such statement is made. We undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for us to predict all such factors, nor can we assess the impact of each such factor or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement. Some of these risks and uncertainties are discussed in our 2008 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.

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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	2009	2008
Operating revenues:		
Gross operating revenues	$ 437,355	$ 387,694
Less: Cost of sales	284,174	245,920
Revenue taxes	10,542	9,351
Net operating revenues	142,639	132,423
Operating expenses:		
Operations and maintenance	33,955	28,458
General taxes	8,491	8,134
Depreciation and amortization	15,522	17,705
Total operating expenses	57,968	54,297
Income from operations	84,671	78,126
Other income and expense - net	890	173
Interest charges - net of amounts capitalized	9,370	9,430
Income before income taxes	76,191	68,869
Income tax expense	28,828	25,701
Net income	$ 47,363	$ 43,168
Average common shares outstanding:		
Basic	26,501	26,409
Diluted	26,597	26,560
Earnings per share of common stock:		
Basic	$ 1.79	$ 1.63
Diluted	$ 1.78	$ 1.63

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, 2009	March 31, 2008	Dec. 31, 2008
Assets:			
Plant and property:			
Utility plant	$ 2,158,946	$ 2,071,072	$ 2,142,988
Less accumulated depreciation	663,417	627,265	659,123
Utility plant - net	1,495,529	1,443,807	1,483,865
Non-utility property	80,689	68,815	74,506
Less accumulated depreciation	9,665	8,261	9,314
Non-utility property - net	71,024	60,554	65,192
Total plant and property	1,566,553	1,504,361	1,549,057
Current assets:			
Cash and cash equivalents	10,341	6,417	6,916
Accounts receivable	99,985	82,775	81,288
Accrued unbilled revenue	61,034	56,025	102,688
Allowance for uncollectible accounts	(4,948)	(4,066)	(2,927)
Regulatory assets	124,085	6,288	147,319
Fair value of non-trading derivatives	4,798	34,175	4,592
Inventories:			
Gas	82,182	25,663	86,134
Materials and supplies	9,846	8,834	9,933
Income taxes receivable	1,804	-	20,811
Prepayments and other current assets	26,339	20,652	24,216
Total current assets	415,466	236,763	480,970
Investments, deferred charges and other assets:			
Regulatory assets	284,166	179,173	288,470
Fair value of non-trading derivatives	189	1,227	146
Other investments	68,302	56,164	54,132
Other	17,691	10,601	5,377
Total investments, deferred charges and other assets	370,348	247,165	348,125
Total assets	$ 2,352,367	$ 1,988,289	$ 2,378,152

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, 2009	March 31, 2008	Dec. 31, 2008
Capitalization and liabilities:			
Capitalization:			
Common stock	$ 335,261	$ 332,182	$ 336,754
Earnings invested in the business	332,900	299,923	296,005
Accumulated other comprehensive income (loss)	(4,323)	(2,840)	(4,386)
Total common stock equity	663,838	629,265	628,373
Long-term debt	587,000	512,000	512,000
Total capitalization	1,250,838	1,141,265	1,140,373
Current liabilities:			
Notes payable	88,600	54,600	248,000
Long-term debt due within one year	-	5,000	-
Accounts payable	93,304	93,061	94,422
Taxes accrued	14,224	23,160	12,455
Interest accrued	11,215	11,287	2,785
Regulatory liabilities	46,475	88,197	20,456
Fair value of non-trading derivatives	107,461	1,703	136,735
Other current and accrued liabilities	41,414	34,970	36,467
Total current liabilities	402,693	311,978	551,320
Deferred credits and other liabilities:			
Deferred income taxes and investment tax credits	267,827	221,670	257,831
Regulatory liabilities	239,561	220,137	228,157
Pension and other postretirement benefit liabilities	140,318	42,709	138,229
Fair value of non-trading derivatives	15,387	4,995	21,646
Other	35,743	45,535	40,596
Total deferred credits and other liabilities	698,836	535,046	686,459
Commitments and contingencies (see Note 11)	-	-	-
Total capitalization and liabilities	$ 2,352,367	$ 1,988,289	$ 2,378,152

See Notes to Consolidated Financial Statements.

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

Thousands	Three Months Ended March 31, 2009	2008
Operating activities:		
Net income	$ 47,363	$ 43,168
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and amortization	15,522	17,705
Deferred income taxes and investment tax credits	9,848	14,432
Undistributed gains from equity investments	(288)	(25)
Deferred gas savings - net	33,974	3,740
Non-cash expenses related to qualified defined benefit pension plans	2,490	780
Deferred environmental costs	(2,669)	(2,048)
Income from life insurance investments	(1,081)	(459)
Settlement of interest rate hedge	(10,096)	-
Deferred regulatory and other	(15,020)	(13,679)
Changes in working capital:		
Accounts receivable and accrued unbilled revenue - net	25,837	9,822
Inventories of gas, materials and supplies	4,039	45,447
Income taxes receivable	19,007	-
Prepayments and other current assets	3,677	4,917
Accounts payable	(928)	(28,409)
Accrued interest and taxes	10,199	18,483
Other current and accrued liabilities	5,013	5,405
Cash provided by operating activities	146,887	119,279
Investing activities:		
Investment in utility plant	(21,641)	(19,263)
Investment in non-utility property	(6,171)	(1,682)
Proceeds from life insurance	120	-
Contributions to non-utility investments	(900)	(1,500)
Other	(5,483)	(63)
Cash used in investing activities	(34,075)	(22,508)
Financing activities:		
Common stock issued (purchased) - net	(1,184)	1,874
Long-term debt issued	75,000	-
Change in short-term debt	(172,251)	(88,500)
Cash dividend payments on common stock	(10,468)	(9,903)
Other	(484)	68
Cash used in financing activities	(109,387)	(96,461)
Increase in cash and cash equivalents	3,425	310
Cash and cash equivalents - beginning of period	6,916	6,107
Cash and cash equivalents - end of period	$ 10,341	$ 6,417
Supplemental disclosure of cash flow information:		
Interest paid	$ 816	$ 1,017

Income taxes paid	$ -	$ 350

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. Basis of Financial Statements and Accounting Policies

The consolidated financial statements include the accounts of Northwest Natural Gas Company (NW Natural), which consist of our regulated gas distribution business, our regulated gas storage businesses, which includes our wholly-owned subsidiary Gill Ranch Storage, LLC (Gill Ranch), and other investments and business activities, which includes our wholly-owned subsidiary NNG Financial Corporation (Financial Corporation) and an equity investment in a proposed natural gas transmission pipeline (Palomar) (see Note 2).

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 businesses and other non-utility investments and business activities. Intercompany accounts and transactions have been eliminated, except for transactions required by regulatory accounting not to be eliminated under Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of 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 2008 Annual Report on Form 10-K (2008 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.

Investments in corporate joint ventures and partnerships in which our ownership interest is 50 percent or less and over which we do not exercise control are accounted for by the equity method or the cost method.

Our accounting policies are described in Note 1 of the 2008 Form 10-K. There were no significant changes to those accounting policies during the three months ended March 31, 2009. See below for a further discussion of newly adopted standards and recent accounting pronouncements.

Newly Adopted Standards

Business Combinations. Effective January 1, 2009, we adopted SFAS No. 141R, "Business Combinations." This statement amends the principles and requirements for how an acquiror accounts for and discloses its business combinations. The adoption of SFAS No. 141R did not have a material effect on our financial condition, results of operations or cash flows.

Noncontrolling Interests. Effective January 1, 2009, we adopted SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements." This statement amends the reporting requirements of Accounting Research Bulletin No. 51 for noncontrolling interests in subsidiaries to improve the relevance, comparability and transparency of the financial information disclosed. The adoption of SFAS No. 160 did not have a material effect on our financial condition, results of operations or cash flows.

Derivative Instruments and Hedging Activities. Effective January 1, 2009, we adopted SFAS No. 161, "Accounting for Derivative Instruments and Hedging Activities," which requires enhanced disclosures of derivative instruments and hedging activities. SFAS No. 161 expands disclosures by adding qualitative disclosures about our hedging objectives and strategies, fair value gains and losses, and credit-risk-related contingent features in derivative agreements. The disclosures are intended to provide an enhanced understanding of:

· how and why we use derivative instruments;
· how derivative instruments and related hedge items are accounted for under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," and its related interpretations; and
· how derivative instruments and related hedged items affect our financial condition, results of operations and cash flows.

The adoption and implementation of this statement did not have, and is not expected to have a material effect on our financial statement disclosures. The required disclosures are included in Note 10, below.

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Determining Whether Share-Based Payment Transactions are Participating Securities. Effective January 1, 2009, we adopted FASB Staff Position (FSP) No. EITF 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities." This statement requires nonforfeitable rights to dividends or dividend equivalents on unvested share-awards to be included in the computation of earnings per share under the two-class method. The adoption of FSP No. EITF 03-6-1 did not have, and is not expected to have, a material effect on our financial condition, results of operations or cash flows.

Recent Accounting Pronouncements

Pensions. In December 2008, the FASB issued SFAS No. 132R-1, "Employers' Disclosures about Pensions and Other Postretirement Benefits," which requires enhanced disclosures of plan assets in an employer's defined benefit pension or other postretirement benefit plan. SFAS No. 132R-1 is effective for reporting periods ending after December 15, 2009. The disclosures are intended to provide an enhanced understanding of:

- how investment allocation decisions are made;
- the major categories of plan assets;
- the inputs and valuation techniques used to measure the fair value of plan assets;
- the effect of fair value measurements using significant unobservable inputs (Level 3 input from SFAS No. 157, "Fair Value Measurements") on changes in plan assets for the period; and
- significant concentration or risk within plan assets.

The adoption of SFAS No. 132R-1 is not expected to have a material effect on our financial statement disclosures.

Interim Disclosures about Financial Instruments. In April 2009, the FASB issued FSP SFAS No. 107-1 and Accounting Principles Board (APB) No. 28-1, "Interim Disclosures about Fair Value of Financial Instruments." This statement requires disclosures about the fair value of financial instruments to be made in interim reporting periods where summarized financial information is issued. FSP SFAS No. 107-1 and APB No. 28-1 will be effective for interim reporting periods ending after June 15, 2009. The adoption of this statement is not expected to have a material effect on our disclosures.

Fair Value Considerations. In April 2009, the FASB issued FSP SFAS No. 157-4, "Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly." This pronouncement provides an outline and required disclosures, if necessary, to determine if the market for measuring our financial instruments has significantly decreased in volume and level of activity. FSP SFAS No. 157-4 is effective for interim and annual reporting periods ending after June 15, 2009. The adoption of this statement is not expected to have a material effect on our financial condition, results of operations or cash flows.

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 either 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, and our "other" segment includes an equity investment in Palomar and our Financial Corporation subsidiary.

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The following table presents information about the reportable segments. Inter-segment transactions are insignificant.

Thousands	Three Months Ended March 31, Utility	Gas Storage	Other	Total
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
2008				
Net operating revenues	$ 127,379	$ 4,997	$ 47	$ 132,423
Depreciation and amortization	17,379	326	-	17,705
Income from operations	73,877	3,843	406	78,126
Net income	40,542	2,353	273	43,168
Total assets at March 31, 2008	1,908,870	65,969	13,450	1,988,289
Total assets at December 31, 2008	$ 2,289,601	$ 72,073	$ 16,478	$ 2,378,152

Included in total assets at March 31, 2009 and 2008, our major non-utility investments were as follows:

- Mist gas storage (excluding utility) was $56.0 million and $56.2 million, respectively;
- Gill Ranch was $19.0 million and $0.1 million, respectively;
- Palomar was $15.5 million and $7.6 million, respectively;
- Financial Corporation was $1.0 million and $1.1 million, respectively; and
- Investment in Boeing 737 (leveraged lease) was $0.0 million and $3.6 million, respectively, as it was sold in April 2008.

In March 2009, Gill Ranch entered into a $40 million cash collateralized credit facility that expires on September 30, 2009. As of March 31, 2009, Gill Ranch had borrowed loan proceeds of $5.8 million with an effective interest rate of LIBOR plus 50 basis points.

Palomar had executed precedent agreements whereby a significant majority of the pipeline capacity was committed to one shipper. In April 2009, Palomar and that shipper replaced their existing precedent agreement with a new agreement for the same amount of capacity and Palomar received cash proceeds which had supported the shipper's obligations under the prior agreement. Our maximum loss exposure related to Palomar at March 31, 2009 would be limited to our investment balance of $15.5 million less any commitments or credit support from third parties.

3. Capital Stock

As of March 31, 2009, common shares authorized were 100,000,000 and outstanding were 26,504,188.

We have a share repurchase program for our common stock under which we purchase shares on the open market or through privately negotiated transactions. Since inception of the repurchase program in 2000, the Board has authorized repurchases through May 31, 2010 up to an aggregate 2.8 million shares or $100 million. No shares were repurchased under this program during the three months ended March 31, 2009. To date, a total of 2.1 million shares or $83.3 million have been repurchased.

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4. Stock-Based Compensation

Our stock-based compensation plans consist of the Long-Term Incentive Plan (LTIP), the Restated Stock Option Plan (Restated SOP) and the Employee Stock Purchase Plan (ESPP). These plans are designed to promote stock ownership by employees and officers. For additional information on our stock-based compensation plans, see Part II, Item 8., Note 4, in the 2008 Form 10-K and current updates provided below.

Long-Term Incentive Plan. On February 25, 2009, 39,000 performance-based shares were granted under the LTIP based on target-level awards, which include a market condition, with a weighted-average grant date fair value of $9.59 per share. Fair value was estimated as of the date of grant using a Monte-Carlo option pricing model based on the following weighted-average assumptions:

Stock price on valuation date	$41.15
Performance term (in years)	3.0
Quarterly dividends paid per share	$0.395
Expected dividend yield	3.8%
Dividend discount factor	0.8927

In February 2009, the Board approved the payout of our 2006-08 performance-based stock awards. Shares were purchased on the open market to satisfy the approved awards.

Restated Stock Option Plan. On February 25, 2009, options to purchase 111,750 shares were granted under the Restated SOP, with an exercise price equal to the closing market price of $41.15 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 $5.46 per share. Fair value was estimated as of the date of grant using the Black-Scholes option pricing model based on the following weighted-average assumptions:

Risk-free interest rate	2.0%
Expected life (in years)	4.7
Expected market price volatility factor	22.5%
Expected dividend yield	3.8%
Forfeiture rate	3.7%

As of March 31, 2009, there was $1.1 million of unrecognized compensation cost related to the unvested portion of outstanding stock option awards expected to be recognized over a period extending through 2012.

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5. Long-Term Debt

On March 25, 2009, we issued $75 million of 5.37 percent secured medium-term notes (MTNs) due February 1, 2020. Proceeds from these MTNs were used to redeem short-term debt of the utility and for general corporate purposes, including funding utility capital expenditures and working capital needs.

At March 31, 2009 and 2008 and December 31, 2008, we had outstanding long-term debt as follows:

Thousands	March 31, 2009 (Unaudited)	March 31, 2008 (Unaudited)	Dec. 31, 2008
Medium-Term Notes			
First Mortgage Bonds:			
6.50 % Series B due 2008(1)	$ -	$ 5,000	$ -
4.11 % Series B due 2010	10,000	10,000	10,000
7.45 % Series B due 2010	25,000	25,000	25,000
6.665% Series B due 2011	10,000	10,000	10,000
7.13 % Series B due 2012	40,000	40,000	40,000
8.26 % Series B due 2014	10,000	10,000	10,000
4.70 % Series B due 2015	40,000	40,000	40,000
5.15 % Series B due 2016	25,000	25,000	25,000
7.00 % Series B due 2017	40,000	40,000	40,000
6.60 % Series B due 2018	22,000	22,000	22,000
8.31 % Series B due 2019	10,000	10,000	10,000
7.63 % Series B due 2019	20,000	20,000	20,000
5.37 % Series B due 2020(2)	75,000	-	-
9.05 % Series A due 2021	10,000	10,000	10,000
5.62 % Series B due 2023	40,000	40,000	40,000
7.72 % Series B due 2025	20,000	20,000	20,000
6.52 % Series B due 2025	10,000	10,000	10,000
7.05 % Series B due 2026	20,000	20,000	20,000
7.00 % Series B due 2027	20,000	20,000	20,000
6.65 % Series B due 2027	20,000	20,000	20,000
6.65 % Series B due 2028	10,000	10,000	10,000
7.74 % Series B due 2030	20,000	20,000	20,000
7.85 % Series B due 2030	10,000	10,000	10,000
5.82 % Series B due 2032	30,000	30,000	30,000
5.66 % Series B due 2033	40,000	40,000	40,000
5.25 % Series B due 2035	10,000	10,000	10,000
	587,000	517,000	512,000
Less long-term debt due within one year	-	5,000	-
Total long-term debt	$ 587,000	$ 512,000	$ 512,000

(1) Redeemed at maturity in July 2008.
(2) Issued on March 25, 2009.

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6. 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 and the potential effects of the assumed exercise of stock options outstanding and estimated stock awards from our other stock-based compensation plans. Diluted earnings per share are calculated as follows:

	Three Months Ended March 31,	
Thousands, except per share amounts	2009	2008
Net income	$ 47,363	$ 43,168
Average common shares outstanding - basic	26,501	26,409
Additional shares for stock-based compensation plans	96	151
Average common shares outstanding - diluted	26,597	26,560
Earnings per share of common stock - basic	$ 1.79	$ 1.63
Earnings per share of common stock - diluted	$ 1.78	$ 1.63

For the three months ended March 31, 2009 and 2008, 6,891 and 1,765 common shares, respectively, were excluded from the calculation of diluted earnings per share because the effect of these additional shares for both periods would have been anti-dilutive.

7. Pension and Other Postretirement Benefits

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

	Pension Benefits		Other Postretirement Benefits	
	Three Months Ended March 31,			
Thousands	2009	2008	2009	2008
Service cost	$ 1,663	$ 1,655	$ 147	$ 133
Interest cost	4,492	4,301	406	349
Expected return on plan assets	(3,995)	(4,777)	-	-
Amortization of loss	1,659	96	4	-
Amortization of prior service cost	306	314	49	49
Amortization of transition obligation	-	-	103	103
Net periodic benefit cost	4,125	1,589	709	634
Amount allocated to construction	(1,178)	(379)	(232)	(207)
Net amount charged to expense	$ 2,947	$ 1,210	$ 477	$ 427

See Part II, Item 8., Note 7, in the 2008 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. This plan, the Western States Office and Professional Employees Pension Fund (Western States Plan), is managed by a Board of Trustees that includes representatives from participating employers and labor unions. Contribution rates are established by collective bargaining 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 can be expected to support. As of

March 31, 2009, the Western States Plan had an accumulated funding deficiency (i.e., a failure to satisfy the minimum funding requirements) for the current plan year and was declared to be 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. Our total contribution to the Western States Plan in 2008 amounted to $0.4 million. We expect the Board of Trustees to impose a 5 percent surcharge to participating employers in 2009 and a 10 percent contribution surcharge for years thereafter, and also reduce benefit rates and adjustable benefits for active employee participants as part of its rehabilitation plan to improve funding status of the plan. It is uncertain as to whether other actions will be necessary, including when higher surcharges may be imposed on participating employers or whether we may withdraw from the plan subject to consent from NW Natural's bargaining unit employees. As we have no current intent to withdraw from the plan, we have not recorded a withdrawal liability.

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Employer Contributions

We make contributions periodically to our single-employer qualified defined benefit pension plans based on actuarial assumptions and estimates, tax regulations and funding requirements under federal law. In April 2009, we made an aggregate $25 million cash contribution for the 2008 plan year. In addition, we made cash contributions for our unfunded, non-qualified pension plans and other postretirement benefit plans in the form of ongoing benefit payments of $0.7 million and $0.6 million during the three months ended March 31, 2009 and 2008, respectively. We also made contributions totaling $0.1 million to the Western States Plan for both the three months ended March 31, 2009 and 2008. For more information see Part II, Item 8., Note 7, in the 2008 Form 10-K.

8. Comprehensive Income

Items that are 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 $4.3 million, $2.8 million and $4.4 million at March 31, 2009 and 2008 and December 31, 2008, respectively, which is related to employee benefit plan liabilities and unrealized gains or losses from derivatives not included under regulatory assets and liabilities (see Note 10, below). The following table provides a reconciliation of net income to total comprehensive income for the three months ended March 31, 2009 and 2008.

	Three Months Ended March 31,	
Thousands	2009	2008
Net income	$ 47,363	$ 43,168
Amortization of employee benefit plan liability, net of tax	63	55
Change in unrealized loss from derivatives, net of tax	-	604
Total comprehensive income	$ 47,426	$ 43,827

9. Fair Value of Financial Instruments

We use fair value measurements to record adjustments to certain financial instruments and to determine fair value disclosures. As of March 31, 2009 and 2008 and December 31, 2008, we recorded our derivatives at fair value according to SFAS No. 157.

In accordance with SFAS No. 157, we use the following fair value hierarchy for determining our derivative fair value measurements:

- Level 1: Valuation is based upon quoted prices for identical instruments traded in active markets;
- Level 2: Valuation is based upon quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active, and model-based valuation techniques for which all significant assumptions are observable in the market; and
- Level 3: Valuation is generated from model-based techniques that use significant assumptions not observable in the market. These unobservable assumptions reflect our own estimates of assumptions market participants would use in valuing the asset or liability.

When developing fair value measurements, it is our policy to use quoted market prices whenever available, or to maximize the use of observable inputs and minimize the use of unobservable inputs when quoted market prices are not available. Derivative contracts outstanding at March 31, 2009 and 2008 and December 31, 2008 were measured at fair value using models or other market accepted valuation methodologies derived from observable market data. These models are primarily industry-standard models that consider various inputs including: (a) quoted future prices for commodities; (b) forward currency prices; (c) time value; (d) volatility factors; (e) current market and contractual prices for underlying instruments; (f) market interest rates and yield curves; and (g) credit spreads, as well as other relevant economic measures.

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In accordance with SFAS No. 157, we include nonperformance risk in calculating fair value adjustments. This includes a credit risk adjustment based on the credit spreads of our counterparties when we are in an unrealized gain position, or on our own credit spread when we are in an unrealized loss position. Our assessment of nonperformance risk is generally derived from the credit default swap market or 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, 2009 and 2008 and December 31, 2008.

The following table provides the fair value measurements for our derivative assets and liabilities as of March 31, 2009 and 2008 and December 31, 2008 in accordance with the fair value hierarchy under SFAS No. 157:

Thousands	Description of Derivative Inputs	March 31, 2009	March 31, 2008	Dec. 31, 2008
Level 1	Quoted prices in active markets	$ -	$ -	$ -
Level 2	Significant other observable inputs	(117,861)	28,704	(153,643)
Level 3	Significant unobservable inputs	-	-	-
		$ (117,861)	$ 28,704	$ (153,643)

10. Derivatives Instruments

We enter into forward contracts and other related financial transactions that qualify as derivative instruments under SFAS No. 133, "Accounting for Derivatives," as amended by SFAS No. 138 and SFAS No. 149 (collectively referred to as SFAS No. 133). We utilize derivative financial instruments primarily to manage commodity prices related to natural gas supply requirements and interest rates related to existing or anticipated debt issuances.

As in the prior two gas years, our strategy entering the 2008-09 gas year (November 1, 2008 – October 31, 2009) was to hedge up to a targeted hedge level of approximately 75 percent of our normal weather anticipated year round sales volumes. 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 purchased gas adjustment filing.

The financially hedged volumes outstanding at March 31, 2009 totaled 391 million therms. These amounts include hedged volumes for the current and next gas year. At March 31, 2009, we were approximately 60 to 70 percent hedged for the remainder of the 2008-09 gas year and approximately 30 percent financially hedged for the 2009-10 gas year based on normal weather anticipated sales volumes.

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In accordance with SFAS No. 161, the following table discloses the amounts and balance sheet presentation of our derivative instruments as of March 31, 2009 and 2008 and December 31, 2008:

Fair Value of Derivative Instruments						
Thousands	Mar. 31, 2009		Mar. 31, 2008		Dec. 31, 2008	
	Current	Non-Current	Current	Non-Current	Current	Non-Current
Assets (1)						
Commodity contracts	$ 4,798	$ 189	$ 34,175	$ 1,227	$ 4,592	$ 146
Total	$ 4,798	$ 189	$ 34,175	$ 1,227	$ 4,592	$ 146
Liabilities (2)						
Commodity contracts	$ 107,307	$ 15,387	$ 1,595	$ 1,383	$ 136,290	$ 9,734
Interest rate contracts	-	-	-	3,613	-	11,912
Foreign exchange contracts	154	-	108	-	445	-
Total	$ 107,461	$ 15,387	$ 1,703	$ 4,996	$ 136,735	$ 21,646

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

In accordance with SFAS No. 161, the following table discloses the amounts and income statement presentation of our derivative instruments. It also illustrates that all fair value measurements are related to regulated utility operations and are deferred to balance sheet accounts in accordance with regulatory accounting under SFAS No. 71 for the three months ended March 31, 2009 and 2008.

Unrealized Gains (Losses) from Derivative Instruments for the three months ended					
	March 31, 2009		March 31, 2008		
Thousands	Commodity contracts (1)	Foreign exchange contracts (3)	Commodity contracts (1)	Interest rate contracts (2)	Foreign exchange contracts (3)
Cost of sales	$ (117,707)	$ -	$ 32,425	$ -	$ -
Other comprehensive income	-	(154)	(564)	(3,613)	(108)
Less:					
Amounts deferred to regulatory accounts on balance sheet	117,707	154	(31,861)	3,613	108
Total impact on earnings	$ -	$ -	$ -	$ -	$ -

(1) Unrealized gain (loss) from commodity hedge contracts is recorded in cost of sales and reclassified to regulatory deferral accounts on the balance sheet in accordance with SFAS No. 71.
(2)

Unrealized gain (loss) from interest rate hedge contracts is recorded in other comprehensive income (loss) and reclassified to regulatory deferral accounts on the balance sheet in accordance with SFAS No. 71.

(3) Unrealized gain (loss) from foreign exchange hedge contracts is recorded in other comprehensive income, and reclassified to regulatory deferral accounts on the balance sheet in accordance with SFAS No. 71.

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In accordance with SFAS No. 161, the gross derivative liability excludes the netting of collateral. We had no collateral posted during the quarter or at the end of the quarter with our derivative counterparties. We calculate our potential exposure to collateral calls by our counterparties to manage our liquidity risk. Based on our current credit rating, most counterparties give us credit limits that range from $15 million to $25 million before we become obligated to post collateral. We measure our collateral call exposure as contractually required under collateral support agreements. To be conservative, we also measure our collateral call exposure with calls for adequate assurance, which is not specific as to amount of credit limit allowed, but could potentially arise if we were to be exposed to a material adverse change. The fair value associated with the amounts in the table below is a $116.3 million unrealized loss. The following table discloses the estimates of potential collateral calls with and without adequate assurance calls, using outstanding derivative instruments at March 31, 2009, based on current gas prices and with various credit rating scenarios for NW Natural.

Thousands	Current Ratings A+/A3	BBB+/Baa1	BBB/Baa2	BBB-/Baa3	Speculative
With Adequate Assurance Calls	$ (1,086)	$ (6,086)	$ (14,361)	$ (35,490)	$ (88,518)
Without Adequate Assurance Calls	$ -	$ -	$ (5,775)	$ (24,403)	$ (72,432)

In the three months ended March 31, 2009, we realized net losses of $79.3 million from the settlement of natural gas hedge contracts, which were recorded as increases to the cost of gas, compared to net gains of $4.3 million in 2008, which were recorded as decreases to the cost of gas. 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 will be amortized to interest expense over the maturity period 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 transact business with us.

Our financial derivative 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. We utilize derivatives to hedge our exposure above risk tolerance limits. Any increase in market risk created by the use of derivatives should be more than offset the exposures they modify.

Some of our counterparties were recently downgraded but continue to maintain strong investment grade credit ratings. Due to current market conditions and credit concerns, we continue to enforce a high level of credit requirements for financial derivative counterparties in accordance with our policy. We actively monitor our derivative credit exposure and place counterparties on hold for trading purposes or require letters of credit, cash collateral or guarantees as circumstances warrant.

Our ongoing assessment of counterparty credit risk includes consideration of credit ratings, the credit default swap market, bond market credit spreads, financial results, 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 trading limits. The duration of our credit risk for all outstanding derivatives currently does not extend beyond October 31, 2010.

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 subject to review and potentially deferred for rate recovery. All of our existing counterparties currently have investment-grade credit ratings, and as of March 31, 2009, we have no exposure to a derivative credit loss with any counterparty.

As of March 31, 2009, all outstanding natural gas hedge contracts were scheduled to mature on or before October 31, 2010.

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11. Commitments and Contingencies

Environmental Matters

We own, or have previously owned, properties that are likely to require environmental remediation or action. We accrue all material loss contingencies relating to these properties that we believe to be probable of assertion and reasonably estimable. We continue to study and evaluate the extent of our potential environmental liabilities at each identified site. Due to the numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several environmental site investigations, the amount or range of potential loss beyond the amounts currently accrued, and the probabilities thereof, cannot currently be reasonably estimated. See Part II, Item 8., Note 12, in the 2008 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 for groundwater source control which ODEQ conditionally approved in March 2008. Source control design is underway. We have a net liability accrued of $19.4 million at March 31, 2009 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). In 2005, ODEQ directed NW Natural to complete a Remedial Investigation/Feasibility Study (RI/FS) for manufactured gas plant wastes on the uplands at this site. ODEQ approved NW Natural's investigation work plan, and field work for the investigations is ongoing. The net liability accrued at March 31, 2009 for the Siltronic site is $0.9 million, which is at the low end of the range of potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot reasonably be estimated.

Portland Harbor site. In 1998, the ODEQ and the U.S. Environmental Protection Agency (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 RI/FS. The submittal of the Remedial Investigation Report to the EPA is expected in 2009, with the submittal of the Feasibility Study to the EPA anticipated in 2010. The EPA and the Lower Willamette Group are conducting focused studies on approximately eleven miles of the lower Willamette River, including the 5.5-mile segment previously studied by the EPA. In 2008, we received a revised estimate and updated our 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. In November 2007, EPA invited all parties (approximately 70) to whom it has thus far sent notices of potential liability for the Portland Harbor site to a meeting to discuss EPA Region 10's expectation of a comprehensive settlement offer regarding implementation of the Portland Harbor record of decision, shortly after it issues such decision . Approximately 60 parties have "convened" to negotiate an agreement outlining the process for a non-judicial allocation. An initial allocation process agreement has been developed and is presently being circulated for execution. As of March 31, 2009, we have a net liability accrued of $12.6 million for this site, which is at the low end of the range of the potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot reasonably be estimated.

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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 the 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 $10.8 million. To date, we have paid $10.2 million on work related to the removal of the tar deposit. As of March 31, 2009, we have a net liability accrued of $0.6 million for our estimate of ongoing costs related to the 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 its list where additional investigation or cleanup is necessary. We are currently performing an environmental investigation of the property with the ODEQ's Independent Cleanup Pathway. As of March 31, 2009, we have a net liability of $0.5 million accrued 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 sediment investigation and a historical report have been submitted to ODEQ . As of March 31, 2009, we accrued an estimated liability 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, 2009 and 2008 and December 31, 2008:

	Current Liabilities			Non-Current Liabilities		
Thousands	March 31, 2009	March 31, 2008	Dec. 31, 2008	March 31, 2009	March 31, 2008	Dec. 31, 2008
Gasco site	$ 8,457	$ 8,444	$ 6,012	$ 10,935	$ 12,406	$ 14,701
Siltronic site	831	1,502	682	114	-	332
Portland Harbor site	-	1,454	277	13,191	12,887	13,642
Central Service Center site	-	-	-	526	529	526
Front Street site	294	-	-	-	-	294
Other sites	-	-	-	64	84	80
Total	$ 9,582	$ 11,400	$ 6,971	$ 24,830	$ 25,906	$ 29,575

Regulatory and Insurance Recovery for Environmental Costs. In May 2003, the Oregon Public Utility Commission (OPUC) approved our request to defer and seek recovery of unreimbursed environmental costs associated with certain named sites, including those described above. Also, beginning in 2006 the OPUC 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, this authorization has been extended through January 25, 2009. We have requested another extension from the OPUC, which is currently pending.

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On a cumulative basis, we have recognized a total of $71.2 million for environmental costs, including legal, investigation, monitoring and remediation costs. Of this total, $36.8 million has been spent to date and $34.4 million is reported as an outstanding liability. At March 31, 2009, we had a regulatory asset of $67.8 million, which includes $32.0 million of total paid expenditures to date, $29.0 million for additional environmental costs expected to be paid in the future and accrued interest of $6.8 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 but continue to anticipate that our overall insurance recovery effort will extend over several years.

We anticipate that our regulatory recovery of environmental cost deferrals will not be initiated within the next 12 months because we do not expect to have completed our insurance recovery efforts during that time period. 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, 2009 and 2008 and December 31, 2008:

	Non-Current Regulatory Assets		
Thousands	March 31, 2009	March 31, 2008	Dec. 31, 2008
Gasco site	$ 31,493	$ 29,414	$ 30,707
Siltronic site	2,223	2,247	2,327
Portland Harbor site	32,820	30,880	31,791
Central Service Center site	548	545	545
Front Street site	347	-	338
Other sites	350	300	396
Total	$ 67,781	$ 63,386	$ 66,104

Legal Proceedings

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

Oregon Steel Mills site. In 2004, NW Natural was served with a third-party complaint by the Port of Portland (Port) in a Multnomah County Circuit Court case, Oregon Steel Mills, Inc. v. The Port of Portland. The Port alleges that in the 1940s and 1950s petroleum wastes generated by our predecessor, Portland Gas & Coke Company, and 10 other third-party defendants were disposed of in a waste oil disposal facility operated by the United States or Shaver Transportation Company on property then owned by the Port and now owned by Oregon Steel Mills. The complaint seeks contribution for unspecified past remedial action costs incurred by the Port regarding the former waste oil disposal facility as well as a declaratory judgment allocating liability for future remedial action costs. No date has been set for trial and discovery is ongoing. 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.

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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, 2009 and 2008. 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 2008 Annual Report on Form 10-K (2008 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 consist of our regulated local gas distribution business, our regulated gas storage businesses, 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) and 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 2008 Form 10-K).

Executive Summary

Highlights of the first quarter of 2009 include:

- Consolidated net income increased 10 percent from $43.2 million in the first quarter of 2008 to $47.4 million, or $1.78 per share, in the first quarter of 2009;
  - Net operating revenues increased 8 percent from $132.4 million to $142.6 million, largely due to gains from our regulatory share of gas cost savings;
- Income from utility operations increased 9 percent from $73.9 million to $80.9 million, while income from gas storage operations decreased 3 percent from $3.8 million to $3.7 million;
- Cash flow from operations increased 23 percent from $119.3 million to $146.9 million, primarily due to deferred gas cost savings; and
- We celebrated our company's 150th anniversary in January 2009.

Issues, Challenges and Performance Measures

Managing the utility business in a period of gas price volatility. Our gas acquisition strategy is designed to secure sufficient supplies of natural gas to meet the needs of our utility's residential, commercial and industrial customers on firm service. Equally important, however, is our strategy to hedge gas prices for a significant portion of our annual purchase requirements based upon our utility's gas load forecast for core utility customers. We have hedged gas prices for the majority of our gas purchases for the gas contract year that began on November 1, 2008, and we believe we have sufficient supplies of natural gas to meet the needs of our core utility customers. During the first quarter of 2009, the market price of natural gas has continued to be below the prices embedded in our customers' rates through our annual purchased gas adjustment (PGA) resulting in increased margin from our regulatory share of gas cost savings. Gas costs lower than those set in the PGA may positively impact earnings due to an incentive sharing mechanism in Oregon. Conversely, gas costs higher than those set in the PGA may negatively impact earnings and may also affect our competitive advantage because they could reduce our ability to add residential and commercial customers and potentially cause industrial customers to shift their energy needs to alternative fuel sources. Our PGA cost sharing mechanism, along with gas hedging strategies and inventories in storage, enables us to manage and reduce earnings risk exposure due to higher gas costs. We have started to lock in gas prices for next year and may begin to hedge future years prices based on current price levels, and we continue to develop other gas acquisition strategies to manage future gas prices and efficiently meet demands.

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Economic weakness and financial market stress. The overall weakness in the U.S. economy, has resulted in significant negative pressure on consumer demand and business spending. These conditions could have a negative impact on our financial results including certain performance measures such as margins, customer growth rates, bad debt expense, and net interest charges. Our annual customer growth rate slowed to 1.2 percent at March 31, 2009 compared to 2.5 percent at March 31, 2008. Based on current market conditions, we expect customer growth rates in 2009 to continue below 2008 levels, and possibly decline more if economic conditions deteriorate further. Our growth rate has the potential to remain above the national average due to a comparatively low market penetration of natural gas in our service territory, the forecasted population growth in our service territory, the potential for environmental initiatives in Oregon and Washington that could favor natural gas as an energy source, and our efforts to convert existing homes from other heating fuels to natural gas.

Our funding for strategic and other capital investment opportunities is dependent upon our ability to access capital markets and maintain working capital sufficient to meet operating requirements. We intend to continue focusing on: maintaining a strong balance sheet; providing sufficient liquidity resources; monitoring and managing critical business risks; and securing, as needed, proceeds from the issuance of equity or long-term debt securities in order to fund utility and business development capital expenditures. To help mitigate the effect of the negative economic and capital market trends referred to above, we expect to manage costs, extend short-term debt maturities, maintain higher cash balances, maintain the ability to increase the amount of committed credit facilities, and access capital markets as needed to secure proceeds from the issuance of long-term securities for capital expenditure requirements. If we are unable to secure financing to fund certain strategic opportunities, we may look at potentially re-prioritizing the use of existing resources or consider delaying investments until market conditions improve.

We believe that, despite the current economic and credit market environment, our financial condition, including our liquidity position, is strong and we can access capital at reasonable costs. See Part I, Item 1A., “Risk Factors,” and Part II, Item 7., “Financial Condition—Liquidity and Capital Resources,” in our 2008 Form 10-K.

Performance Measures. In order to deal with these and other challenges affecting our business, we recently completed a new strategic plan to map our course over the next several years. The plan includes strategies for further improving our core gas distribution business; for growing our non-utility gas storage business; for investing in new natural gas infrastructure in the region; and for maintaining a leadership role within the gas utility industry by addressing long-term energy policies and pursuing business opportunities that support new clean technologies. The key performance measures we intend to use in monitoring progress against our goals in these areas include, but are not limited to : earnings per share growth; total shareholder return; return on invested capital; utility return on equity; utility customer satisfaction ratings; capital, operations and maintenance expense per customer; and non-utility earnings before interest, taxes, depreciation and amortization, commonly referred to as EBITDA.

Strategic Opportunities

Business Process Improvements. To address our economic and competitive challenges, we intend to continue re-assessing business processes for improved efficiencies. Our goal to integrate, consolidate and streamline operations and support our employees with new technology tools is underway. In 2008, we implemented the first phase of our new enterprise resource planning (ERP) system, and in February 2009 we implemented the second phase with our fixed assets, payroll and construction work management systems. This substantially completes our transition to the new ERP system, which is designed to improve overall operating efficiencies with:

- the integration of systems and data;
- automated control procedures with auditable financial and operational workflows; and
- improved monthly closing and financial reporting processes.

In 2008, we initiated a project to automate the reading of gas meters (AMR) for the remaining two-thirds of our customers. The meters equipped with this technology electronically transmit usage data to receiving devices located in our vehicles as they are driven in the area, substantially reducing the labor costs associated with manually reading meters. The capital cost of this project is estimated to be $30 million, and in January 2009 we filed for and subsequently received approval for regulatory deferral of this investment in Oregon (see "Results of Operations—Regulatory Matters—Rate Mechanisms—AMR Deferral Application," below). Also in 2008, we initiated an automated dispatching system, which provides integrated planning and scheduling with global positioning system capabilities to more effectively collect and distribute data. These technology investments and other initiatives are expected to facilitate process improvements and contribute to long-term operational efficiencies throughout NW Natural.

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Gas Storage Development. In September 2007, we initiated a joint project with Pacific Gas & Electric Company (PG&E) to develop an underground natural gas storage facility near Fresno, California. We formed a wholly-owned subsidiary, Gill Ranch, to plan, develop and operate the facility. In July 2008, Gill Ranch filed an application with the California Public Utilities Commission (CPUC) for a Certificate of Public Convenience and Necessity. In December 2008, the CPUC indicated that our application qualified for a Mitigated Negative Declaration, which allows an expedited review process. We expect to receive a decision on our application by the end of this year. Gill Ranch will become subject to CPUC regulation regarding various matters including, but not limited to, securities issuances, lien grants and sales of property. We estimate our share of the total cost of this project to be between $160 and $180 million. Our share represents 75 percent of the total cost of the initial phase of storage development, which includes an estimated 20 Bcf of gas storage capacity and approximately 27 miles of gas transmission pipeline. The initial phase of gas storage at Gill Ranch is currently scheduled to be in-service by late 2010.

Pipeline Diversification. Currently, we depend on a single interstate pipeline company to ship gas supplies to our system. Palomar Gas Transmission, LLC (Palomar), a wholly-owned subsidiary of Palomar Gas Holdings, LLC, (PGH), is seeking to build a new transmission pipeline that would connect with our 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 a 217-mile natural gas transmission pipeline in Oregon designed to serve our utility and the growing markets in Oregon and other parts of the western United States. The project includes an east and west segment. The east segment of the Palomar pipeline 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 additional interconnections including a possible connection to one of the several liquefied natural gas (LNG) terminals proposed to be built on the Columbia River. The east segment of Palomar would diversify NW Natural's 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. The west segment of Palomar would also provide our utility customers with access to a new source of gas supply if an LNG terminal is built on the Columbia River. 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. See "Financial Condition—Investing Activities," below for further discussion on Palomar.

Earnings and Dividends

Net income was $47.4 million, or $1.78 per share, for the three months ended March 31, 2009, compared to $43.2 million, or $1.63 per share, for the same period last year.

The primary factors contributing to the $4.2 million increase in net income were:

· an $8.4 million gain in utility margin from our regulatory share of gas cost savings, compared to a margin loss of $0.4 million from our share of gas cost increases in the first quarter of 2008; and
· a $2.5 million increase from a regulatory adjustment for income taxes paid versus collected in rates.

Partially offsetting the above factors were:

· a $5.5 million increase in operations and maintenance expense primarily due to increases in incentive pay accruals, employee pension costs and bad debt expense; and
· a decrease in utility margin from industrial sales and transportation of $0.9 millions due to lower volumes.

Dividends paid on our common stock were 39.5 cents per share in the first quarter of 2009, compared to 37.5 cents per share in the first quarter of 2008. In April 2009, the Board of Directors declared a quarterly dividend on our common stock of 39.5 cents per share, payable on May 15, 2009 to shareholders of record on April 30, 2009. The current indicated annual dividend rate is $1.58 per share.

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Application of Critical Accounting Policies and Estimates

In preparing our financial statements using generally accepted accounting principles in the United States of America, 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;
- income taxes; and
- environmental contingencies.

There have been no material changes to the information provided in the 2008 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 2008 Form 10-K). Management has discussed the 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.

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Results of Operations

Regulatory Matters

Regulation and Rates

We are currently subject to regulation with respect to, among other matters, rates and systems of accounts set by the Oregon Public Utility Commission (OPUC), Washington Utilities and Transportation Commission (WUTC) and FERC. The OPUC and WUTC 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 2008 Form 10-K.

At March 31, 2009 and 2008 and at December 31, 2008, the amounts deferred as regulatory assets and liabilities were as follows:

	Current		
Thousands	March 31, 2009	March 31, 2008	Dec. 31, 2008
Regulatory assets:			
Unrealized loss on non-trading derivatives(1)	$ 107,461	$ 1,703	