NORTHWEST NATURAL GAS CO
Form 10-Q
May 02, 2008
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

(Mark One)

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended March 31, 2008

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 is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definition of accelerated filer, large 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 ¨

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, 2008, 26,415,248 shares of the registrant s Common Stock (the only class of Common Stock) were outstanding.

Table of Contents

NORTHWEST NATURAL GAS COMPANY

For the Quarterly Period Ended March 31, 2008

NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Statements of Income

(Unaudited)

Thousands, except per share amounts	**Three Months Ended March 31, 2008**	**2007**
Operating revenues:		
Gross operating revenues	$ 387,694	$ 394,091
Less: Cost of sales	245,920	245,469
Revenue taxes	9,351	9,614
Net operating revenues	132,423	139,008
Operating expenses:		
Operations and maintenance	28,458	28,839
General taxes	8,134	7,817
Depreciation and amortization	17,705	16,785
Total operating expenses	54,297	53,441
Income from operations	78,126	85,567
Other income and expense - net	173	538
Interest charges - net of amounts capitalized	9,430	9,567
Income before income taxes	68,869	76,538
Income tax expense	25,701	28,463
Net income	$ 43,168	$ 48,075
Average common shares outstanding:		
Basic	26,409	27,229
Diluted	26,560	27,385
Earnings per share of common stock:		
Basic	$ 1.63	$ 1.77
Diluted	$ 1.63	$ 1.76

See Notes to Consolidated Financial Statements.

Table of Contents

NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Balance Sheets

Thousands	**March 31, 2008 (Unaudited)**	**March 31, 2007 (Unaudited)**	**Dec. 31, 2007**
Assets:			
Plant and property:			
Utility plant	$ 2,071,072	$ 1,981,639	$ 2,052,161
Less accumulated depreciation	627,265	585,008	615,533
Utility plant - net	1,443,807	1,396,631	1,436,628
Non-utility property	68,815	45,767	67,149
Less accumulated depreciation and amortization	8,261	7,149	7,904
Non-utility property - net	60,554	38,618	59,245
Total plant and property	1,504,361	1,435,249	1,495,873
Current assets:			
Cash and cash equivalents	6,417	5,094	6,107
Accounts receivable	82,775	89,489	69,442
Accrued unbilled revenue	56,025	43,468	78,004
Allowance for uncollectible accounts	(4,066)	(4,235)	(2,890)
Regulatory assets	6,288	13,702	17,598
Fair value of non-trading derivatives	34,175	13,698	2,903
Inventories:			
Gas	25,663	41,828	71,079
Materials and supplies	8,834	9,501	8,865
Prepayments and other current assets	20,652	14,761	25,569
Total current assets	236,763	227,306	276,677
Investments, deferred charges and other assets:			
Regulatory assets	179,173	155,297	175,938
Fair value of non-trading derivatives	1,227	3,734	324
Other investments	56,164	48,247	54,070
Other	10,601	8,526	11,179
Total investments, deferred charges and other assets	247,165	215,804	241,511
Total assets	$ 1,988,289	$ 1,878,359	$ 2,014,061

See Notes to Consolidated Financial Statements.

Table of Contents

NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Balance Sheets

Thousands	March 31, 2008 (Unaudited)	March 31, 2007 (Unaudited)	Dec. 31, 2007
Capitalization and liabilities:			
Capitalization:			
Common stock	$ 332,182	$ 363,519	$ 331,595
Earnings invested in the business	299,923	269,172	266,658
Accumulated other comprehensive income (loss)	(2,840)	(2,324)	(3,502)
Total common stock equity	629,265	630,367	594,751
Long-term debt	512,000	517,000	512,000
Total capitalization	1,141,265	1,147,367	1,106,751
Current liabilities:			
Notes payable	54,600	5,500	143,100
Long-term debt due within one year	5,000	9,500	5,000
Accounts payable	93,061	92,185	119,731
Taxes accrued	23,160	43,116	13,137
Interest accrued	11,287	11,409	2,827
Regulatory liabilities	88,197	41,888	61,326
Fair value of non-trading derivatives	1,703	9,447	14,829
Other current and accrued liabilities	34,970	22,832	29,794
Total current liabilities	311,978	235,877	389,744
Deferred credits and other liabilities:			
Deferred income taxes and investment tax credits	221,670	207,648	206,340
Regulatory liabilities	220,137	208,333	213,764
Pension and other postretirement benefit liabilities	42,709	54,117	41,619
Fair value of non-trading derivatives	4,995	3,108	3,758
Other	45,535	21,909	52,085
Total deferred credits and other liabilities	535,046	495,115	517,566
Commitments and contingencies (see Note 10)			
Total capitalization and liabilities	$ 1,988,289	$ 1,878,359	$ 2,014,061

See Notes to Consolidated Financial Statements.

Table of Contents

NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Statements of Cash Flows

(Unaudited)

Thousands	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007
Operating activities:		
Net income	$ 43,168	$ 48,075
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and amortization	17,705	16,785
Deferred income taxes and investment tax credits	14,432	(3,381)
Undistributed earnings (loss) from equity investments	(25)	78
Deferred gas costs - net	3,740	14,242
Non-cash expenses related to qualified defined benefit pension plans	780	1,064
Deferred environmental costs	(2,048)	(2,800)
Income from life insurance investments	(459)	(480)
Deferred regulatory costs and other	(13,679)	(2,940)
Changes in working capital:		
Accounts receivable and accrued unbilled revenue - net	9,822	37,997
Inventories of gas, materials and supplies	45,447	26,799
Prepayments and other current assets	4,917	4,280
Accounts payable	(28,409)	(21,394)
Accrued interest and taxes	18,483	30,371
Other current and accrued liabilities	5,405	1,141
Cash provided by operating activities	119,279	149,837
Investing activities:		
Investment in utility plant	(19,263)	(18,609)
Investment in non-utility property	(1,682)	(3,104)
Contributions to non-utility equity investments	(1,500)	
Other	(63)	2,660
Cash used in investing activities	(22,508)	(19,053)
Financing activities:		
Common stock issued, net of expenses	1,874	1,737
Common stock repurchased		(9,017)
Long-term debt retired		(20,000)
Change in short-term debt	(88,500)	(94,600)
Cash dividend payments on common stock	(9,903)	(9,677)
Other	68	100
Cash used in financing activities	(96,461)	(131,457)
Increase (decrease) in cash and cash equivalents	310	(673)
Cash and cash equivalents - beginning of period	6,107	5,767

Cash and cash equivalents - end of period	$	6,417	$	5,094
Supplemental disclosure of cash flow information:				
Interest paid	$	1,017	$	1,101
Income taxes paid	$	350	$	9,000

See Notes to Consolidated Financial Statements.

Table of Contents

NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Notes to Consolidated Financial Statements

(Unaudited)

1. Basis of Financial Statements

The consolidated financial statements include the accounts of Northwest Natural Gas Company (NW Natural), which primarily consist of our regulated gas distribution business, our regulated gas storage business including our wholly-owned subsidiary Gill Ranch Storage, LLC (Gill Ranch), and other businesses including our wholly-owned subsidiary NNG Financial Corporation (Financial Corporation) and a joint venture in a natural gas transmission pipeline (see Note 8).

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 2007 Annual Report on Form 10-K (2007 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.

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

2. New Accounting Standards

Adopted Standards

Fair Value Measurements. In September 2006, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 157, Fair Value Measurements, which is effective for fiscal years beginning after November 15, 2007 and for interim periods within those years. This statement defines fair value, establishes a framework for measuring fair value and expands the related disclosure requirements. This statement indicates, among other things, that a fair value measurement assumes that the transaction to sell an asset or transfer a liability occurs in the principal market for the asset or liability or, in the absence of a principal market, the most advantageous market for the asset or liability. SFAS No. 157 defines fair value based upon an exit price model.

Relative to SFAS No. 157, the FASB issued FASB Staff Positions (FSP) 157-1 and 157-2. FSP 157-1 amends SFAS No. 157 to exclude SFAS No. 13, Accounting for Leases, and its related interpretive accounting pronouncements that address leasing transactions, while FSP 157-2 delays the effective date of the application of SFAS No. 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and liabilities that are recognized or disclosed at fair value in the financial statements on a nonrecurring basis.

We adopted SFAS No. 157 as of January 1, 2008, with the exception of the application of the statement to nonrecurring nonfinancial assets and liabilities. Nonrecurring nonfinancial assets and liabilities for which we have not applied the provisions of SFAS No. 157 include asset retirement obligations initially measured at fair value and business combinations initially measured at fair value. The adoption of SFAS No. 157 did not have, and is not expected to have, a material effect on our financial condition, results of operations or cash flow.

Table of Contents

Fair Value Option for Financial Assets and Liabilities. In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities, which permits entities to choose to measure many financial instruments and certain other items at fair value. SFAS No. 159 is effective for years beginning after November 15, 2007. We have elected not to implement the fair value option for financial assets and liabilities.

Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards. On January 1, 2008, we adopted Emerging Issues Task Force (EITF) 06-11, Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards, which provides the accounting requirements for recognizing income tax benefits received on dividends paid to employees holding equity-classified nonvested shares, equity-classified nonvested share units or equity-classified outstanding share options, and how these benefits are charged to retained earnings under SFAS No. 123R, Share Based Payment. The adoption of EITF 06-11 did not have, and is not expected to have, a material effect on our financial condition, results of operations or cash flow.

Offsetting Amounts Related to Certain Contracts. On January 1, 2008, we adopted FSP FASB Interpretation No. 39-1 (FSP FIN 39-1), Offsetting of Amounts Related to Certain Contracts. FSP FIN 39-1 requires disclosure when a reporting entity offsets fair value amounts from derivative instruments executed with the same counterparty under master netting arrangements. Our disclosures on FSP FIN 39-1 are included in Note 7.

The adoption and implementation of FSP FIN 39-1 did not have, and is not expected to have, a material effect on our financial condition, results of operations or cash flow.

Recent Accounting Pronouncements

Business Combinations. In December 2007, the FASB issued SFAS No. 141R, Business Combinations. This statement amends the principles and requirements for how the acquiror accounts for and discloses its business combinations as described under SFAS No. 141. SFAS No. 141R is effective for fiscal years and interim periods beginning after December 15, 2008. Based on our preliminary assessment, this statement is not expected to have a material effect on our financial condition, results of operations or cash flow.

Noncontrolling Interests in Consolidated Financial Statements. In December 2007, the FASB issued 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. SFAS No. 160 is effective for fiscal years and interim periods beginning after December 15, 2008. Based on the nature of this new requirement, we may be required to disclose additional information, but it is not expected to have a material effect on our financial condition, results of operations or cash flow.

Derivative Instruments and Hedging Activities. In March 2008, the FASB issued SFAS No. 161, Accounting for Derivative Instruments and Hedging Activities, which requires enhanced disclosures of derivative instruments and hedging activities. SFAS No. 161 is effective for fiscal years beginning after November 15, 2008.

SFAS No. 161 will expand current disclosures by adding qualitative disclosures about our hedging objectives and strategies, the fair value gains and losses, and our credit-risk-related contingent features in derivative agreements. The disclosures will 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 flow.

As SFAS No. 161 relates only to disclosures, there will be no effect on our financial condition, results of operations or cash flow.

Table of Contents

3. Earnings Per Share

Basic earnings per share are computed based on the weighted average number of common shares outstanding during each period presented. Diluted earnings per share reflect the potential effects of the exercise of stock options. Diluted earnings per share are calculated as follows:

	Three Months Ended March 31,	
	2008	**2007**
Net income	$ 43,168	$ 48,075
Average common shares outstanding - basic	26,409	27,229
Additional shares for stock-based compensation plans	151	156
Average common shares outstanding - diluted	26,560	27,385
Earnings per share of common stock - basic	$ 1.63	$ 1.77
Earnings per share of common stock - diluted	$ 1.63	$ 1.76

For the three month period ended March 31, 2008, 135,319 common shares were excluded from the calculation of diluted earnings per share because the effect would have been antidilutive. For the three month period ended March 31, 2007, no common shares were excluded from the calculation of diluted earnings per share.

4. Capital Stock

At March 31, 2008, we had 60,000,000 common shares authorized and 26,412,248 common shares outstanding.

We have a Board approved repurchase program for our common stock. During the three months ended March 31, 2008, no shares of common stock were repurchased pursuant to this program. On April 24, 2008, the Board extended the program through May 31, 2009 and confirmed the authorization to repurchase up to an aggregate of 2.8 million or up to an aggregate of $100 million. As of March 31, 2008, total common stock repurchases under this program since inception in 2000 totaled 2.1 million shares or $83.3 million.

5. Stock-Based Compensation

Our stock-based compensation plans consist of the Long-Term Incentive Plan (LTIP), the Restated Stock Option Plan (Restated SOP), the Employee Stock Purchase Plan (ESPP) and the Non-Employee Directors Stock Compensation Plan (NEDSCP). These plans are designed to promote stock ownership by employees and officers and, in the case of the NEDSCP, non-employee directors. For additional information on our stock-based compensation, see Part II, Item 8., Note 4, in the 2007 Form 10-K.

Table of Contents

Long-Term Incentive Plan. A total of 500,000 shares of NW Natural s common stock have been authorized for awards under the terms of the LTIP as stock bonus, restricted stock or performance-based stock awards. During the quarter ended March 31, 2008, 48,500 performance-based shares were granted under the LTIP, based on target-level awards, with a weighted-average grant date fair value of $10.89 per share. During February 2008, the Board of Directors amended and restated our Deferred Compensation Plan for Directors and Executives to eliminate the ability to defer any LTIP stock award payouts into cash accounts. Stock-based compensation related to the outstanding LTIP share awards was re-valued as of the amendment date, and the accounting for these awards was changed from the liability method to the equity method in accordance with SFAS No. 123R. The fair value was estimated as of the date of grant using the Monte-Carlo option pricing model based on the following weighted-average assumptions:

Stock price on valuation date	$ 43.29
Performance term (in years)	3.0
Dividends paid per share	$ 0.375
Dividend yield	3.4%
Dividend discount factor	0.9026

Restated Stock Option Plan. In February 2008, we granted 114,050 stock options under the Restated SOP, with an exercise price equal to the closing market price of our common stock on the date of grant, vesting over the four-year period following date of grant and a term of 10 years and 7 days. The 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	2.8%
Expected life (in years)	4.7
Expected market price volatility factor	18.4%
Expected dividend yield	3.5%
Forfeiture rate	3.8%

As of March 31, 2008, there was $1.4 million of unrecognized compensation cost related to the unvested portion of outstanding stock option awards expected to be recognized over a period extending through 2011.

Table of Contents

6. Long-Term Debt

At March 31, 2008 and 2007 and December 31, 2007, we had outstanding long-term debt as follows:

Thousands	March 31, 2008 (Unaudited)	March 31, 2007 (Unaudited)	Dec. 31, 2007
Medium-Term Notes			
First Mortgage Bonds:			
6.80 % Series B due 2007 [1]	$	$ 9,500	$
6.50 % Series B due 2008	5,000	5,000	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
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
	517,000	526,500	517,000
Less long-term debt due within one year	5,000	9,500	5,000
Total long-term debt	$ 512,000	$ 517,000	$ 512,000

[1] Redeemed at maturity in May 2007.

7. Use of Financial Derivatives

We enter into forward contracts and other related financial transactions that qualify as derivative instruments under SFAS No. 133, 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 (see Part II, Item 8., Note 11, in the 2007 Form 10-K).

Table of Contents

At March 31, 2008 and 2007, unrealized gains and losses from mark-to-market valuations of our derivative instruments were primarily reported as regulatory liabilities or regulatory assets because the realized gains or losses at settlement are either included, or are expected to be included, in utility rates pursuant to regulatory deferral mechanisms (see Part II, Item 8., Note 1, in the 2007 Form 10-K). Estimated fair value of unrealized gains and losses were as follows:

	March 31, 2008		March 31, 2007		Dec. 31, 2007	
Thousands	**Current**	**Non-Current**	**Current**	**Non-Current**	**Current**	**Non-Current**
Fair Value Gain (Loss), net:*						
Natural gas hedges	$ 32,580	$ (155)	$ 4,282	$ 626	$ (12,099)	$ (2,104)
Interest rate hedge contract		(3,613)				(1,330)
Foreign currency forward purchase contracts	(108)		(31)		173	
Total	$ 32,472	$ (3,768)	$ 4,251	$ 626	$ (11,926)	$ (3,434)

* Some derivative instruments include offsetting fair value amounts as they are executed with the same counterparty under the same master netting arrangement.

In the first quarter of 2008, we realized net gains of $4.3 million from the settlement of natural gas hedge contracts, which were recorded as reductions to the cost of gas, compared to net losses of $7.6 million in the same period of 2007, which were recorded as increases to the cost of gas. The currency exchange rate in all foreign currency forward purchase contracts is included in our cost of gas at settlement; therefore, no gain or loss was recorded from the settlement of those contracts. The interest rate hedge contract outstanding at December 31, 2007 and March 31, 2008 qualifies as a cash flow hedge for accounting purposes, and changes in the value of this cash flow hedge is included in deferred regulatory accounts or other comprehensive income, assuming 100 percent hedge effectiveness. There were no realized gains or losses from the interest rate hedge during the first quarter of 2008.

As of March 31, 2008, all outstanding natural gas hedge contracts will mature on or before October 31, 2009. The maturity date for our interest rate swap contract is September 30, 2008. We expect to cash settle this contract concurrently with our next long-term debt issuance, which is expected to occur in the second half of 2008.

8. Segment Information

Our core business segment is the local gas distribution segment, also referred to as the utility, which involves the distribution and sale of natural gas. Another business segment, gas storage, represents natural gas storage services provided to intrastate and interstate customers and asset optimization services under a contract with an independent energy marketing company. Gas storage also includes Gill Ranch, our wholly-owned subsidiary. The remaining business segment, other, primarily consists of our wholly-owned subsidiary, Financial Corporation, as well as various other non-utility investments, including an investment in a leveraged aircraft lease and our equity investment in a proposed natural gas pipeline project with TransCanada Gas Transmission Northwest (GTN). On April 23, 2008, we sold our investment in the aircraft (see Note 13).

Table of Contents

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

	Three Months Ended March 31,			
Thousands	Utility	Gas Storage	Other	Total
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
2007				
Net operating revenues	$ 135,549	$ 3,410	$ 49	$ 139,008
Depreciation and amortization	16,563	222		16,785
Income from operations	82,595	2,941	31	85,567
Net income	46,108	1,795	172	48,075
Total assets at March 31, 2007	$ 1,831,806	$ 39,004	$ 7,549	$ 1,878,359

9. Pension and Other Postretirement Benefits

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

	Three Months Ended March 31,			
	Pension Benefits		Other Postretirement Benefits	
Thousands	2008	2007	2008	2007
Service cost	$ 1,655	$ 2,159	$ 133	$ 148
Interest cost	4,301	3,995	349	320
Expected return on plan assets	(4,777)	(4,636)		
Amortization of loss	96	539		1
Amortization of prior service cost	314	245	49	49
Amortization of transition obligation			103	103
Net periodic benefit cost	1,589	2,302	634	621
Amount allocated to construction	(379)	(515)	(207)	(202)
Net amount charged to expense	$ 1,210	$ 1,787	$ 427	$ 419

See Part II, Item 8., Note 7, in the 2007 Form 10-K for more information about our pension and other postretirement benefit plans.

Employer Contributions

During the three months ended March 31, 2008, we did not make and were not required to make cash contributions to our qualified non-contributory defined benefit pension plans, but cash contributions in the form of ongoing benefit payments of $0.6 million were made for our unfunded, non-qualified supplemental pension plans and other postretirement benefit plans. See Part II, Item 8., Note 7, in the 2007 Form 10-K for a discussion of estimated future payments.

Table of Contents

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 be reasonably estimated. See Part II, Item 8., Note 12, in the 2007 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 2008, the estimated liability for this site decreased by $0.4 million due to actual costs paid at this site during the first three months of 2008. We have a net liability of $20.9 million at March 31, 2008 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 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 working with the ODEQ to develop a study of manufactured gas plant wastes on the uplands at this site. In 2008, the estimated liability for this site decreased by less than $0.1 million due to actual costs paid at this site during the first three months of 2008. The net liability at March 31, 2008 for the Siltronic site is $1.5 million, which is at the low end of the range of potential additional liability because no amount within the range is considered to be more likely than another and the high end of the range cannot 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 Remedial Investigation/Feasibility Study (RI/FS), completion of which is currently expected in 2009. 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 2007, we received a revised estimate and updated our estimate for additional expenditures related to RI/FS development and environmental remediation. In 2008, the estimated liability for this site decreased by $0.5 million due to actual costs paid at this site during the first three months of 2008. As of March 31, 2008, we have a net liability of $13.3 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 be estimated.

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 $9.8 million on work related to the removal of the tar deposit. As of March 31, 2008, we have a net liability of this site of $1.0 million remaining for our estimate of ongoing costs, 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 be estimated.

Table of Contents

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 has been 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. As of March 31, 2008, we have an estimated liability of $0.5 million for this site. We cannot reasonably estimate a range of liability until studies are completed.

Front Street site. The Front Street site was the former location of a gas manufacturing plant operated by our predecessor. 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. Until the results of that sampling are evaluated, a future cost cannot be reasonably estimated.

Oregon Steel Mills site. See Legal Proceedings, below.

Accrued Liabilities Relating to Environmental sites. Until 2007, we had not been able to determine the timing of our environmental liabilities and therefore had classified no liabilities as current prior to June 2007. The following table summarizes the accrued liabilities relating to environmental sites at March 31, 2008 and 2007 and December 31, 2007:

	March 31, 2008		**March 31, 2007**		**Dec. 31, 2007**	
Thousands	**Current**	**Non-Current**	**Current**	**Non-Current**	**Current**	**Non-Current**
Gasco site	$ 8,444	$ 12,406	$	$ 6,249	$ 6,901	$ 14,342
Siltronic site	1,502			62		1,540
Portland Harbor site	1,454	12,887		1,703		14,821
Central Service Center site		529				529
Other sites		84		155		167
Total	$ 11,400	$ 25,906	$	$ 8,169	$ 6,901	$ 31,399

Regulatory and Insurance Recovery for Environmental Matters. In May 2003, the Oregon Public Utility Commission (OPUC) approved our request for deferral of environmental costs associated with specific sites, including the Gasco, Siltronic and Portland Harbor sites. An extension request of the original deferral order is pending with the OPUC, which will allow us to defer and seek recovery of unreimbursed environmental costs in a future general rate case through early 2009. The extension request also asks for additional named sites to be included in the deferral order. 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. As of March 31, 2008, we have paid a cumulative total of $26.1 million relating to the named sites since the effective date of the deferral authorization.

On a cumulative basis, we have recognized a total of $68.2 million for environmental costs, including legal, investigation, monitoring and remediation costs. Of this total, $30.9 million has been spent to date and $37.3 million is reported as an outstanding liability. At March 31, 2008, we had a regulatory asset of $63.4 million, which includes $26.1 million of total paid expenditures to date, $33.4 million for additional environmental costs expected to be paid in the future and accrued interest of $3.9 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 some portion 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 legislation 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 will not 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 regulatory assets relating to environmental matters at March 31, 2008 and 2007 and December 31, 2007:

	Non-Current Regulatory Assets		
Thousands	**March 31, 2008**	**March 31, 2007**	**Dec. 31, 2007**
Gasco site	$ 29,414	$ 10,836	$ 29,042
Siltronic site	2,247	477	2,227
Portland Harbor site	30,880	16,770	30,869
Central Service Center site	545	15	545
Other sites	300	199	371
Total	$ 63,386	$ 28,297	$ 63,054

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 these matters will have a material adverse 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. In March 2005, motions to dismiss by ourselves and other third-party defendants were denied on the basis that the failure of the Port to plead and prove that we were in violation of law was an affirmative defense that may be asserted at trial, but did not provide a sufficient basis for dismissal of the Port s claim. 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 adverse effect on our financial condition, results of operations or cash flows.

Table of Contents

11. 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 total common stock equity is $2.8 million at March 31, 2008, which is related to employee benefit plan liabilities and changes in price risk management activities. The following table provides a reconciliation of net income to total comprehensive income for the three months ended March 31, 2008 and 2007.

Thousands	Three Months Ended March 31, 2008	2007
Net income	$ 43,168	$ 48,075
Amortization of employee benefit plan liability, net of tax	55	32
Change in unrealized loss from price risk management activities, net of tax	604	
Total comprehensive income	$ 43,827	$ 48,107

12. Fair Value of Financial Instruments

We use fair value measurements to record fair value adjustments to certain financial instruments and to determine fair value disclosures. As of March 31, 2008, we recorded our derivatives at fair value according to SFAS No. 157. As we elected not to implement SFAS No. 159, we did not measure our long-term debt at fair value (see Note 2).

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 pricing the asset or liability.

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, when developing fair value measurements. Derivative contracts outstanding at March 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 futures prices for commodities, (b) forward currency prices, (c) time value, (d) volatility factors, (e) current market and contractual prices for underlying instruments, and (f) market interest rates and yield curves as well as other relevant economic measures.

The following table provides the fair value hierarchy of our derivative assets and liabilities as of March 31, 2008:

Thousands	Fair Value Measurements at March 31, 2008 Using: Quoted prices in active markets (Level	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)	Total Carrying Value at March 31, 2008

	1)			
Derivative assets	$	$ 35,402	$	$ 35,402
Derivative liabilities		(6,698)		(6,698)
	$	$ 28,704	$	$ 28,704

Table of Contents

All fair value measurements of our derivative contracts outstanding at March 31, 2008 were determined to be within Level 2 of the fair value hierarchy. The fair value of our derivative contracts were primarily reported as regulatory assets or regulatory liabilities because the realized gains or losses at settlement are either included, or expected to be included, in utility rates pursuant to regulatory deferral mechanisms (see Part II, Item 8., Note 1. in the 2007 Form 10-K).

13. Subsequent Events

On April 23, 2008, NW Natural sold its investment in a Boeing 737-300 aircraft for approximately $6.2 million cash, plus accrued rents. The airplane was purchased in 1987 and leased to Continental Airlines, and currently the airplane continues under lease to Continental. An after-tax gain of approximately $1.1 million will be recognized in the second quarter of 2008.

Table of Contents

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. The discussion refers to our consolidated activities for the three months ended March 31, 2008 and 2007. Unless otherwise indicated, references in this discussion to Notes are to the Notes to Consolidated Financial Statements in this report.

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). These accounts principally consist of 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 gas distribution business, and the term non-utility is used to describe our gas storage business (gas storage) and our other regulated and non-regulated investments and business activities (other segment) (see Strategic Opportunities, below, and Note 8).

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

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 the 2007 Form 10-K).

Executive Summary

Highlights from the first quarter of 2008 include:

- Consolidated net income was $43.2 million and earnings per share was $1.63 in the first quarter of 2008, compared to $48.1 million and $1.76 per share in 2007. Last year s first quarter included pre-tax earnings of $9.8 million from regulatory sharing of gas cost savings and $2.7 million from gains on derivative contracts, both of which increased net income from our utility segment;

- Net income from our gas storage segment increased 31 percent to $2.4 million;

- Operations and maintenance expense decreased by 1 percent to $28.5 million; and

- Cash flow from operations decreased 20 percent to $119.3 million, primarily reflecting lower net income and temporary rate reduction to customers gas bills to amortize last year s large gas cost savings balance.

Issues, Challenges and Performance Measures

Managing the 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 core customers. Equally important, however, is our strategy to hedge gas prices for a significant portion of our annual purchase requirements based upon our core utility s gas load forecast. We believe we have sufficient supplies of natural gas to meet the needs of our core customers, but price increases could change our earnings outlook and our competitive advantage. If gas prices increase, it could negatively impact earnings due to losses from our incentive gas cost sharing mechanism. It could also affect our ability to add residential and commercial customers and could result in industrial customers shifting their businesses energy needs to alternative fuel sources. We continue to develop new gas acquisition strategies to manage gas prices and to efficiently meet market demands.

Customer growth. Our growth is largely driven by new residential construction, and while we expect to continue with a customer growth rate above the national average for local gas distribution companies due to the growing market in the Pacific Northwest, we have experienced a slowdown in new construction which is expected to continue through 2008. Based on the current outlook for housing starts, we anticipate that our annual growth rate could decline further in 2008. The current period slowdown in new construction was partially offset by a modest rebound in residential conversions from other fuels to natural gas. For the three months ended March 31, 2008, our annual growth rate was 2.5 percent, compared to 2.8 percent for the comparable period ended March 31, 2007. A prolonged slowdown in residential new construction could adversely impact our future results of operations (see Part II, Item 7., Executive Summary Issues, Challenges and Performance Measures, in the 2007 Form 10-K).

Strategic Opportunities

Business Process Redesign. To address these economic and competitive challenges we continue to refine our new operating model to improve the business processes where additional efficiencies can be gained. In the first quarter of 2008, we implemented the first phase of our new integrated information system and immediately initiated the second phase. This technology investment and other initiatives are expected to facilitate process improvements and improve overall operational efficiencies throughout NW Natural. For more information regarding our redesign efforts, see Part II, Item 7., Strategic Opportunities, in the 2007 Form 10-K.

Pipeline Diversification. In September 2006, we announced that we were evaluating a possible equity investment in a natural gas transmission pipeline that would connect TransCanada Gas Transmission Northwest s (GTN) interstate transmission line to our local gas distribution system. The proposed pipeline (Palomar Pipeline) is intended to diversify our gas delivery options, including the enhancement of reliability for our customers by providing an alternate transportation path for, and an alternative gas supply source to, gas purchases in Alberta. Plans also include the possible delivery of supplies from proposed liquefied natural gas (LNG) facilities that are currently proposed on the Columbia River. The planning and permitting phase of the Palomar Pipeline project is expected to occur through 2009 and cost approximately $30 million, 50 percent of which would be contributed by us. We, along with GTN, will determine at a later date whether to proceed with development of the project beyond the permitting phase. If constructed, we estimate the total cost for the entire 220-mile pipeline to be between $600 million and $700 million. For more information regarding our pipeline diversity efforts, see Part II, Item 7., Strategic Opportunities, in the 2007 Form 10-K.

Gas Storage Development. In September 2007, we announced a joint project with Pacific Gas & Electric Company to develop an underground natural gas storage facility near Fresno, California. We formed Gill Ranch to develop and operate the facility. Based on a strong level of interest from prospective customers in response to an open season to gauge interest in the storage facility, which was conducted from October 2007 to December 2007, we expect to proceed with filing an application with the California Public Utilities Commission for a Certificate of Public Convenience and Necessity in mid-2008. We estimate our share of the total cost for the initial phase of development to be about $160 million over the next three years, which represents 75 percent of the estimated phase one project cost. For more information regarding our gas storage development efforts, see Part II, Item 7., Strategic Opportunities, in the 2007 Form 10-K.

Earnings and Dividends

Net income was $43.2 million, or $1.63 a share, for the three months ended March 31, 2008, compared to $48.1 million, or $1.76 a share, for the same period last year.

Factors contributing to lower earnings were:

- decreased net operating revenues (margin) from our regulatory gas cost sharing mechanism, from a margin contribution of $9.8 million in the first quarter of 2007 to a margin reduction of $0.3 million in the first quarter of 2008; and

- increased depreciation expense of $0.9 million due to increases in utility plant and non-utility plant in service.

Partially offsetting the above factors reducing earnings were:

- increased utility volumes from sales to residential and commercial customers, primarily due to an annual customer growth rate of 2.5 percent and weather that was 5 percent colder than average and 7 percent colder than the first quarter of 2007 (see Results of Operations Comparison of Gas Distribution Operations, below);

- increased margin of $1.1 million from a regulatory adjustment for income taxes paid;

- increased margin of $1.6 million from gas storage operations; and

- decreased income tax expense of $2.8 million related to lower taxable income.

Dividends paid on our common stock were 37.5 cents a share and 35.5 cents a share in the three month periods ended March 31, 2008 and 2007, respectively. In April 2008, the Board of Directors declared a quarterly dividend on our common stock of 37.5 cents per share payable May 15, 2008 to shareholders of record on April 30, 2008. The current indicated annual dividend rate is $1.50 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, 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 or judgments involve regulatory cost recovery, revenue recognition, derivative instruments, pension assumptions, income taxes and environmental contingencies (see Part II, Item 7., Application of Critical Accounting Policies and Estimates, in the 2007 Form 10-K). There have been no material changes to the information provided in the 2007 Form 10-K with respect to the application of critical accounting policies and estimates. 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 currently 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 may have an impact on our financial condition, results of operations or cash flows, see Note 2.

Results of Operations

Regulatory Matters

Regulation and Rates

We are subject to regulation with respect to, among other matters, rates, systems of accounts and issuance of securities by the Oregon Public Utility Commission (OPUC) and the Washington Utilities and Transportation Commission (WUTC). Typically, about 91 percent of our utility gas deliveries and operating revenues are derived from Oregon customers and the balance from Washington customers. Future earnings and cash flows from utility operations will be determined largely by the pace of continued growth in the residential and commercial markets 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 2007 Form 10-K.

19

Table of Contents

At March 31, 2008 and 2007 and December 31, 2007, the amounts deferred as regulatory assets and liabilities were as follows:

	Current		
	March 31,		Dec. 31,
Thousands	**2008**	**2007**	**2007**
Regulatory assets:			
Unrealized loss on non-trading derivatives[1]	$ 1,703	$ 9,233	$ 14,788
Pension and other postretirement benefit obligations[2]	1,912	3,567	1,912
Other	2,673	902	898
Total regulatory assets	$ 6,288	$ 13,702	$ 17,598
Regulatory liabilities:			
Gas costs payable	$ 41,422	$ 17,666	$ 46,153
Unrealized gain on non-trading derivatives[1]	33,611	13,698	2,903
Other	13,164	10,524	12,270
Total regulatory liabilities	$ 88,197	$ 41,888	$ 61,326

	Non-Current		
	March 31,		Dec. 31,
Thousands	**2008**	**2007**	**2007**
Regulatory assets:			
Unrealized loss on non-trading derivatives[1]	$ 4,995	$ 3,108	$ 3,758
Income tax asset	69,547	68,086	68,649
Pension and other postretirement benefit obligations[2]	26,678	49,973	27,152
Environmental costs - paid[3]	30,004	21,912	27,956
Environmental costs - accrued but not yet paid[3]	33,459	6,462	35,098
Other	14,490	5,756	13,325
Total regulatory assets	$ 179,173	$ 155,297	$ 175,938
Regulatory liabilities:			
Gas costs payable	$ 7,281	$ 10,354	$ 6,290
Unrealized gain on non-trading derivatives[1]	1,227	3,734	324
Accrued asset removal costs	209,248	191,886	204,886
Other	2,381	2,359	2,264
Total regulatory liabilities	$ 220,137	$ 208,333	$ 213,764

1 Unrealized gains or losses on non-trading derivatives do not earn a rate of return or a carrying charge. These amounts, when realized at settlement, are recoverable through utility rates as part of our purchased gas adjustment (PGA) mechanism.

2 Pension and other postretirement costs are approved for regulatory deferral based on SFAS No. 87 and SFAS No. 106 expense included in customer rates (see Part II, Item 8., Note 7, in the 2007 Form 10-K).

[3] Environmental costs are related to sites that are approved for regulatory deferral. We earn an authorized rate of return as a carrying charge on amounts paid; however, amounts accrued but not yet paid do not earn a rate of return or a carrying charge until expended.

Rate Mechanisms

Purchased Gas Adjustment. Rate changes are applied each year under the PGA tariff mechanisms in Oregon and Washington to reflect changes in the expected cost of natural gas commodity purchases, including contractual arrangements to hedge the purchase price with financial derivatives (see Comparison of Gas Distribution Operations Cost of Gas Sold, below), interstate pipeline demand charges, temporary rate adjustments to amortize balances in deferred regulatory accounts and the removal of temporary rate adjustments effective for the previous year. Under the current PGA mechanisms, we collect an amount for purchased gas costs based on estimates included in rates. If the actual purchased gas costs differ from the estimated amounts included in

Table of Contents

rates, then we are required to defer that difference and pass it on to customers as an adjustment to future rates. As part of an incentive sharing mechanism in Oregon, only 67 percent of the difference is deferred such that the impact on current earnings is either a charge to expense for 33 percent of the higher cost of gas sold, or a credit to expense for 33 percent of the lower cost of gas sold. In Washington, the PGA deferral is 100 percent of the higher or lower actual cost of gas sold.

The OPUC is currently conducting a formal review of the PGA process used by local distribution companies covering gas portfolio requirements, incentive sharing levels and filing requirements among other items. The review of the structure of the PGA mechanism is expected to be completed by fall 2008. Implementation of any changes to the PGA mechanism is expected to be effective with the 2008 PGA filing.

Excess Earnings Test. The OPUC has a formalized process to test for excess utility earnings annually. We are authorized to retain all of our earnings up to a threshold level equal to our authorized return on equity of 10.2 percent plus 300 basis points. One-third of any earnings above that level will be refunded to customers. The excess earnings threshold is subject to adjustment up or down each year depending on movements in long-term interest rates. For 2007, the threshold after adjustment was 13.40 percent. We do not expect that any amounts will be required to be refunded to customers as a result of the 2007 earnings test, which will be reviewed by the OPUC during the second quarter of 2008. In Washington, we are not subject to an annual excess earnings test and 100 percent of all prudently incurred gas costs are passed to customers in rates.

Integrated Resource Planning. The OPUC and WUTC have implemented integrated resource planning (IRP) processes under which utilities develop plans defining alternative growth scenarios and resource acquisition strategies. We filed our IRP with the OPUC on April 14, 2008 and filed an update to our IRP with the WUTC on April 15, 2008. Elements of the plan include:

- an evaluation of supply and demand resources;
- the consideration of uncertainties in the planning process and the need for flexibility to respond to changes;
- a primary goal of least cost service; and
- consistency with state energy policy.

Although the OPUC s order acknowledging the IRP does not constitute ratemaking approval of any specific resource acquisition or expenditure, the OPUC generally indicates that it would give considerable weight in prudency reviews to utility actions that are consistent with acknowledged plans. We expect a decision in Oregon and Washington by the third quarter of 2008.

Pipeline Integrity Cost Recovery. In July 2004, the OPUC approved the accounting treatment and full recovery for the cost of our pipeline integrity management program, a program mandated by the Pipeline Safety Improvement Act of 2002 and the related rules adopted by the U.S. Department of Transportation s Pipeline and Hazardous Materials Safety Administration. We classify our costs as either capital expenditures or regulatory assets, accumulate the costs over each 12 months ending September 30, and recover the costs, subject to audit, through rate changes effective with the annual PGA. The accounting and rate treatment for these costs extends through September 30, 2008 and management intends to seek approval of an extension of such treatment after that date. We do not have any special accounting or rate treatment for pipeline integrity costs incurred in the state of Washington.

In March 2008, the OPUC and WUTC approved our request to waive certain maintenance activities in connection with our investigation on some potentially defective valves. We intend to seek recovery of remediation costs related to these valves in Oregon, if any, through our pipeline integrity management program. We expect to complete the investigation and develop our remediation plan by the third quarter of 2008.

Washington General Rate Case. On March 28, 2008, we filed a request for a 4.8 percent margin increase in Washington as part of a general rate case. The last general rate increase in Washington was approved in 2004. The rate increase is requested to cover increased operating costs and investments in our distribution system. In this rate filing, we have also proposed a conservation decoupling mechanism that mirrors the mechanism that has been in effect in Oregon since 2002.

Table of Contents

Comparison of Gas Distribution Operations

The following tables summarize the composition of gas utility volumes, operating revenues and margin for the three months ended March 31, 2008 and 2007:

Thousands, except degree day and customer data	Three months ended March 31, 2008	Three months ended March 31, 2007	Favorable/ (Unfavorable)
Utility volumes - therms:			
Residential sales	182,368	162,897	19,471
Commercial sales	106,956	96,804	10,152
Industrial - firm sales	14,542	15,917	(1,375)
Industrial - firm transportation	48,986	43,471	5,515
Industrial - interruptible sales	26,042	25,664	378
Industrial - interruptible transportation	70,382	67,738	2,644
Total utility volumes sold and delivered	449,276	412,491	36,785
Utility operating revenues - dollars:			
Residential sales	$ 225,683	$ 227,138	$ (1,455)
Commercial sales	114,964	118,042	(3,078)
Industrial - firm sales	13,822	16,655	(2,833)
Industrial - firm transportation	1,586	1,498	88
Industrial - interruptible sales	19,681	22,131	(2,450)
Industrial - interruptible transportation	2,095	2,093	2
Regulatory adjustment for income taxes paid (1)	1,055		1,055
Other revenues	3,756	3,068	688
Total utility operating revenues	382,642	390,625	(7,983)
Cost of gas sold	245,912	245,462	(450)
Revenue taxes	9,351	9,614	263
Utility net operating revenues (margin)	$ 127,379	$ 135,549	$ (8,170)
Utility margin: (2)			
Residential sales	$ 87,592	$ 81,036	$ 6,556
Commercial sales	34,634	32,338	2,296
Industrial - sales and transportation	8,331	8,379	(48)
Miscellaneous revenues	1,728	1,639	89
Other margin adjustments	(7)	10,951	(10,958)
Margin before regulatory adjustments	132,278	134,343	(2,065)
Weather normalization mechanism	(7,548)	108	(7,656)
Decoupling mechanism	1,594	1,098	496
Regulatory adjustment for income taxes paid (1)	1,055		1,055
Utility margin	$ 127,379	$ 135,549	$ (8,170)
Customers - end of period:			
Residential customers	594,431	579,746	14,685
Commercial customers	62,035	60,987	1,048
Industrial customers	949	953	(4)

Total number of customers - end of period	657,415	641,686	15,729
Actual degree days	1,980	1,852	
Percent colder (warmer) than average [3]	5%	(1%)	

(1) Regulatory adjustment for income taxes paid is described below under Regulatory Adjustment for Income Taxes Paid.

(2) Amounts reported as margin for each category of customers is net of demand charges and revenue taxes.

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

Our utility results are affected by, among other things, customer growth and 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 contributes to changes in margin based on changes in residential and commercial customer consumption, and we have a weather normalization mechanism that adjusts customer bills up or down based on the estimated margin impact 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 2007 Form 10-K). Both mechanisms are designed to reduce the volatility of our utility earnings.

Table of Contents

Total utility margin decreased $8.2 million or 6 percent in the three months ended March 31, 2008 compared to 2007, with residential and commercial customers contributing an increase of $8.9 million to margin in 2008 over 2007, not including the effects of the weather normalization and decoupling mechanisms. Total margin from industrial and transportation sales remained about the same. The weather normalization and decoupling mechanisms decreased margin by a net $7.2 million in the first quarter of 2008 compared to 2007, primarily reflecting colder weather. A decrease in regulatory gas cost sharing of $0.3 million also contributed to the decrease in margin, while the regulatory adjustment for income taxes paid added $1.1 million to margin in 2008 (see Cost of Gas Sold, below and Regulatory Adjustment for Income Taxes Paid, below).

Volume increases in the first quarter of 2008 were due mainly to colder weather and residential and commercial customer growth, which reflects a net increase of 15,729 customers since March 31, 2007, or an annual growth rate of 2.5 percent. Our growth rate has slowed from past years but continues to remain above the national average for local gas distribution companies. Recent economic and housing market conditions have slowed the level of new construction in our service territory.

Residential and commercial sales markets are impacted by seasonal weather patterns, energy prices, competition from alternative energy sources and economic conditions. 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 the weather normalization mechanism in Oregon where about 90 percent of our customers are served. Approximately 90 percent of our eligible Oregon customers are covered by the mechanism. 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 our customers so that we do not have an incentive to discourage customers from conserving energy. 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, the mechanisms do not fully insulate the utility from earnings volatility due to weather and conservation. Our weather normalization mechanism reduced margin by $7.5 million for the quarter ended March 31, 2008 based on weather that was 5 percent colder than average, compared to an increase of $0.1 million in margin for the quarter ended March 31, 2007 based on weather that was 1 percent warmer than average. The weather normalization mechanism is designed to balance our margins when weather deviates from average.

Our decoupling mechanism increased margin by $1.6 million in the first quarter of 2008, after adjusting for price elasticity in the annual Oregon PGA filing, compared to a margin increase of $1.1 million in the 2007 quarter. Decoupling is designed to adjust our margin to reflect changes in customer usage due to conservation efforts.

Residential and Commercial Sales

The primary factors affecting residential and commercial volumes and operating revenues in the first quarter this year over last year include:

- sales volumes were 11 percent higher as a result of colder weather and customer growth; and
- utility operating revenues were 1 percent lower due to lower billing rates, which reflect the lower gas costs in the PGA effective November 1, 2007, and adjustments for the weather normalization mechanism, partially offset by the 11 percent higher sales volumes.

Total utility operating revenues include accruals for unbilled revenues (gas delivered but not yet billed to customers) 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, 2008, accrued unbilled revenue was $56.0 million, compared to $43.5 million at March 31, 2007, with the increase primarily reflecting colder weather toward the end of March 2008 as compared to March 2007.

Table of Contents

Industrial Sales and Transportation

The primary factors affecting industrial sales and transportation volumes and operating revenues in the first quarter this year over last year include:

- total volumes delivered to industrial sales and transportation customers increased 7.2 million therms, or 5 percent, in the first quarter of 2008 as compared to the same period in 2007, primarily due to a shift from oil to natural gas by some industrial customers in response to higher oil prices;

- utility operating revenues related to these customers decreased $5.2 million, or 12 percent, compared to the first quarter of 2007; the lower operating revenues are primarily caused by the lower cost of gas and higher gas cost deferral refunds included in rates from a rate decrease effective November 1, 2007; on a year-to-year basis, margin is a better indication of performance for the industrial sector due to the shifting of customers between sales service and transportation service; and

- in 2008, the change in utility margin from industrial customers was negligible.

Regulatory Adjustment for Income Taxes Paid

During 2005, the Oregon legislature passed legislation, effective January 1, 2006, intended to ensure that utilities do not collect in rates more income taxes than they actually pay to taxing authorities. Based upon revised rules issued by the OPUC in September 2007, our 2007 tax report for the 2006 tax year was filed on October 15, 2007. For the 2006 tax year, we estimated that the utility was entitled to recover $1.7 million through a surcharge to our Oregon utility customers. The 2006 surcharge was primarily driven by gains from gas cost savings from our PGA incentive sharing mechanism in 2006. The OPUC approved the amount of the surcharge on April 11, 2008 (Order No. 08-202). The increase in Oregon revenues will go into effect June 1, 2008 through a one-time billing adjustment to customers.

Our 2008 tax report for the 2007 tax year will be filed on October 15, 2008 and our 2009 tax report for the 2008 tax year will be filed on October 15, 2009. Both of these reports are subject to a formal review by the OPUC. The OPUC will issue final orders by April 1 of the year following the respective filing, with rate adjustments effective as of June 1. As the provisions apply to NW Natural, if the Oregon regulated utility records higher operating income as compared to its latest general rate case, customers would be surcharged for the increase in income taxes paid. Conversely, if the Oregon regulated utility records lower operating income as compared to its latest rate case, customers would receive refunds for the decrease in income taxes paid. Based on current information, we estimate that the utility will be entitled to recover $4.7 million through a surcharge to our Oregon utility customers for the 2007 tax year. Based on our operating results through March 31, 2008, we estimate that the utility will again be assessing a surcharge for taxes paid in excess of taxes collected in rates and have recognized an estimated surcharge of $0.7 million. At December 31, 2007, we recognized an estimated surcharge for the 2006 and 2007 tax years of $1.7 million and $4.3 million, respectively. We have revised our estimated surcharge for the 2007 tax year to $4.7 million from $4.3 million. For the three months ended March 31, 2008, we recognized an estimated surcharge for the revised 2007 estimate and the 2008 estimate for a total of $1.1 million. These amounts are included in gross operating revenues.

Other Revenues

Other revenues include miscellaneous fee income as well as utility revenue adjustments reflecting deferrals to, or amortizations from, regulatory asset or liability accounts other than deferred gas costs (see Part II, Item 8., Note 1, Industry Regulation, in the 2007 Form 10-K). Other revenues were $3.8 million in the first quarter of 2008, compared to $3.1 million in the first quarter of 2007, primarily due to an increase in customer fees.

Cost of Gas Sold

The total cost of gas sold was $245.9 million in the first quarter of 2008, an increase of $0.5 million or less than 1 percent compared to the first quarter of 2007. The cost per therm of gas sold includes current gas purchases, gas drawn from storage inventory, gains and losses from commodity hedges, margin from off-system gas sales, pipeline demand charges, seasonal demand cost balancing adjustments, regulatory gas cost deferrals and company gas use. The average cost of gas sold decreased from 81 cents per therm in the first quarter of 2007 to 75 cents in the first quarter of 2008. The 7 percent decrease in cost per therm was offset by the 9 percent increase in total volumes sold.

24

Under the PGA tariff in Oregon, our net income is affected within defined limits by changes in purchased gas costs (see Part II, Item 7., Results of Operations Regulatory Matters Rate Mechanisms Purchased Gas Adjustment, in the 2007 Form 10-K). During the three months ended March 31, 2008, our actual gas costs were higher than the gas costs embedded in rates, while during 2007 our actual gas costs were lower than the gas costs embedded in rates. The effect on shareholders was a gain of $9.8 million during the first three months of 2007, compared to a reduction to margin of $0.3 million during the first three months of 2008.

We use natural gas derivatives, primarily fixed-price commodity swaps, under the terms of our Financial Derivatives Policy, to help manage our exposure to floating price gas purchase contracts (see Application of Critical Accounting Policies and Estimates Accounting for Derivative Instruments and Hedging Activities, in the 2007 Form 10-K and Note 7). We realized net gains of $4.3 million and losses of $7.6 million from our financial hedges in first quarters of 2008 and 2007, respectively. Gains and losses from the financial hedging of utility gas purchases generally are included in cost of gas, but normally do not impact net income because the hedges are usually factored into our PGA and annual rate changes. To the extent that any utility gas hedge is entered into after the annual PGA filing, then the gains and losses are subject to our PGA incentive sharing mechanism with 67 percent deferred and 33 percent recorded to current income.

Business Segments Other than Gas Distribution Operations

Gas Storage

Our gas storage segment primarily consists of the non-utility portion of our Mist underground storage facility, asset optimization and our wholly-owned subsidiary, Gill Ranch. We earned $2.4 million in net income from our gas storage business segment in the three months ended March 31, 2008 after regulatory sharing and income taxes, which is equivalent to 9 cents per share, compared to net income of $1.8 million, or 7 cents per share, in the three months ended March 31, 2007. This increase was primarily due to increased firm storage services revenues and an increase in revenues from our asset optimization arrangement with an independent energy marketing company (see Part II, Item 7., Results of Operations Business Segments Other Than Local Gas Distribution Gas Storage, in the 2007 Form 10-K).

In Oregon, we retain 80 percent of the pre-tax income from gas storage services as well as from third party optimization revenues when the costs of the capacity used have not been included in utility rates, or 33 percent of the pre-tax income from such storage and optimization when the capacity costs have been included in utility rates. The remaining 20 percent and 67 percent, respectively, are credited to a deferred regulatory account for crediting to our core utility customers. We have a similar sharing mechanism in Washington for pre-tax income derived from storage services and third-party optimization.

In 2008, a total of 100,000 therms per day of Mist storage capacity that had previously been available for interstate storage services will be recalled and committed to use for core utility customers. This is the first instance of recalled capacity since 2004. Under a regulatory agreement with the OPUC, non-utility gas storage at Mist, which has been developed in advance of core utility customer needs for interstate storage services, can be recalled to serve core utility customers. Storage capacity recalled is added to retail utility rate base at its original cost less accumulated depreciation. Utility rates are adjusted with the annual PGA so there is no regulatory lag in rate recovery.

Other

The other business segment primarily consists of a wholly-owned subsidiary, Financial Corporation, as well as various other non-utility investments, including an investment in an aircraft that is leased to a U.S. airline and our equity investment in Palomar Pipeline (see Part II, Item 8., Note 2, Consolidated Subsidiary Operations and Segment Information, in the 2007 Form 10-K).

Table of Contents

Net income from our other business segment for the three months ended March 31, 2008 was $0.3 million, compared to $0.2 million for the three months ended March 31, 2007. Our net investment balance in Financial Corporation at March 31, 2008 and 2007 was $1.1 million and $2.7 million, respectively. The $1.6 million decrease primarily reflects the sale of our limited partnership interest in two wind power electric generation projects in California. Our net investment balance in the aircraft lease at March 31, 2008 and 2007 was $3.6 million and $4.7 million, respectively. Our equity investment balance in the proposed natural gas pipeline project with GTN was $7.6 million at March 31, 2008 and a negligible amount at March 31, 2007. On April 23, 2008, we sold our investment in the aircraft. See Note 13 and Part II, Item 5., below.

Operating Expenses

Operations and Maintenance

Operations and maintenance expense in the first quarter of 2008 was $28.5 million, representing a $0.4 million or 1 percent, decrease from the first quarter of 2007. The following summarizes the major factors that contributed to the decrease in operations and maintenance expense:

- a $1.9 million decrease in payroll and bonus expense;
- offset, in part, by higher expenses related to business development ($0.3 million), regulatory activities ($0.2 million) and facilities costs ($0.3 million).

General Taxes

General taxes, which are principally comprised of property taxes, payroll taxes and regulatory fees, increased $0.3 million, or 4 percent, in the three months ended March 31, 2008 over the same period in 2007. Property taxes increased $0.3 million, or 8 percent, in the first quarter of 2008 compared to the first quarter of 2007 reflecting an increase in net utility plant.

Depreciation and Amortization

Depreciation and amortization expense increased by $0.9 million, or 5 percent, in the three-month period ended March 31, 2008, compared to the same period in 2007. The increased expense reflects ongoing capital expenditures for utility plant, which were made primarily to meet continuing customer growth and to upgrade operating facilities, and increased investments in non-utility plant.

Other Income and Expense Net

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

Thousands	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007
Other income and expense - net:		
Gains from company-owned life insurance	$ 459	$ 480
Interest income (expense)	(1)	152
Other non-operating income (expense)	(93)	(274)
Net interest income (expense) on deferred regulatory accounts	(167)	258
Loss from equity investments of Financial Corporation	(25)	(78)
Total other income and expense - net	$ 173	$ 538

The $0.4 million decrease in other income and expense net in the first quarter of 2008 compared to the same period in 2007 was primarily due to interest on deferred regulatory accounts that were lower because of decreases in deferred environmental costs, largely offset by an increase in other non-operating expenses.

Table of Contents

Interest Charges   Net of Amounts Capitalized

Interest charges   net of amounts capitalized decreased $0.1 million, or 1 percent, in the quarter ended March 31, 2008 compared to the same period in 2007, primarily due to lower balances of total debt outstanding and lower interest rates on short-term borrowings. Our average borrowing rate on short-term debt during the first quarter of 2008 was 3.6 percent, compared to 5.3 percent in the same period last year.

Income Taxes

Income tax expense totaled $25.7 million in the first quarter of 2008 compared to $28.5 million in the first quarter of 2007. The effective tax rate was 37.3 percent in the first quarter of 2008 compared to 37.2 percent in the first quarter of 2007. The lower income tax expense in 2008 is due primarily to pre-tax book income of $68.9 million compared to $76.5 million for the same period in 2007, resulting in lower income tax expense of $2.8 million.

Financial Condition

Capital Structure

Our long-term goal is to maintain a target capital structure comprised 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 meet long-term debt redemption requirements and short-term commercial paper maturities (see   Liquidity and Capital Resources,   below). Achieving the target capital structure and maintaining sufficient liquidity are necessary to maintain attractive credit ratings and have access to capital markets at reasonable costs. Our consolidated capital structure at March 31, 2008 and 2007 and at December 31, 2007, including short-term debt, was as follows:

	March 31,		Dec. 31,
	2008	2007	2007
Common stock equity	52.4%	54.2%	47.4%
Long-term debt	42.6%	44.5%	40.8%
Short-term debt, including current maturities of long-term debt	5.0%	1.3%	11.8%
Total	100.0%	100.0%	100.0%

The common stock equity percentages in March 2008 and March 2007 were higher as compared to December 2007 primarily due to seasonal earnings and cash flows that increased common stock equity and reduced the combined long-term and short-term debt percentages.

On April 24, 2008, the Board authorized an extension to our common stock share repurchase program through May 2009, with an aggregate authorization of up to 2.8 million shares or $100 million. Purchases under this program are made in the open market or through privately negotiated transactions. As of March 31, 2008, total common stock repurchases under this program since inception in 2000 totaled 2.1 million shares or $83.3 million. See   Financing Activities,   and Part II, Item 2.,   Unregistered Sales of Equity Securities and Use of Proceeds,   below.

Liquidity and Capital Resources

At March 31, 2008, we had $6.4 million of cash and cash equivalents compared to $5.1 million at March 31, 2007 and $6.1 million at December 31, 2007. Short-term liquidity is provided by cash from operations and from the sale of commercial paper notes, which are supported by a committed credit facility totaling $250 million and are available through May 31, 2012 (see   Credit Agreement,   below, and Part II, Item 8., Note 6, in the 2007 Form 10-K). Proceeds from the issuance of long-term debt are used to finance capital expenditures and refinance maturing short-term or long-term debt. We expect to issue long-term debt in the second half of 2008 primarily to reduce short-term debt and fund capital expenditures.

Table of Contents

Neither our Mortgage and Deed of Trust nor the indenture under which long-term debt is issued contain credit rating triggers or stock price provisions that require the acceleration of debt repayment. Also, there are no rating triggers or stock price provisions contained in contracts or other agreements with third parties, except for agreements with certain counterparties under our Financial Derivatives Policy. These agreements require the affected party to provide substitute collateral such as cash, guaranty or letter of credit if credit ratings are lowered to non-investment grade or, in some cases, if the mark-to-market value exceeds a certain threshold.

Based on the availability of short-term credit facilities and the ability to issue long-term debt and equity securities, we believe we have sufficient liquidity to satisfy our anticipated cash requirements, including the 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

Since December 31, 2007, our estimated future contractual obligations have not materially changed. Our contractual obligations at December 31, 2007 are described in Part II, Item 7., Financial Condition Liquidity and Capital Resources Contractual Obligations, in the 2007 Form 10-K.

Commercial Paper

Our primary source of short-term funds is from the sale of commercial paper notes. In addition to issuing commercial paper to meet seasonal working capital requirements, including the financing of gas inventories and accounts receivable, short-term debt is used to temporarily fund capital requirements. Commercial paper is periodically refinanced through the sale of long-term debt or equity securities. Our commercial paper program is supported by committed lines of credit (see Credit Agreement, below, and Part II, Item 8., Note 6, in the 2007 Form 10-K). We had $54.6 million in commercial paper notes outstanding at March 31, 2008, compared to $5.5 million outstanding at March 31, 2007 and $143.1 million outstanding at December 31, 2007. Commercial paper balances are typically lower at the end of the first quarter compared to year-end due to collections from higher sales and the withdrawal of gas inventories from storage during the winter heating season.

Credit Agreement

We have a credit agreement for unsecured revolving loans totaling $250 million. The credit agreement is available and committed for a term of five years expiring on May 31, 2012 and may be extended for additional one-year periods thereafter subject to lender approval. The credit agreement allows us to request increases in the total commitment amount, up to a maximum amount of $400 million. The credit agreement also permits the issuance of letters of credit in an aggregate amount up to the applicable total borrowing commitment. All principal and unpaid interest under the credit agreement is due and payable on May 31, 2012, subject to extensions if any. There were no outstanding balances under this credit agreement at March 31, 2008 or December 31, 2007 or under prior credit agreements at March 31, 2007. The credit agreement also requires us to maintain a consolidated indebtedness to total capitalization ratio of 70 percent or less. Failure to comply with this covenant would entitle the lenders to terminate their lending commitments and accelerate the maturity of all amounts outstanding. We were in compliance with this covenant at March 31, 2008 and December 31, 2007. Our previous credit agreements required us to maintain an indebtedness to total capitalization ratio of 65 percent or less, which we were in compliance with at March 31, 2007. For additional information regarding our credit agreement, see Part II, Item 7., Financial Condition Credit Agreement, in the 2007 Form 10-K.

Table of Contents

Credit Ratings

The table below summarizes our debt credit ratings from Standard and Poor s Rating Services (S&P) and Moody s Investors Service (Moody s).

	S&P	Moody s
Commercial paper (short-term debt)	A-1+	P-1
Senior secured (long-term debt)	AA-	A2
Senior unsecured (long-term debt)	A+	A3
Ratings outlook	Stable	Positive

Both rating agencies have assigned NW Natural an investment grade rating. These 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

Redemptions of long-term debt during the quarter ended March 31, 2008 and 2007 and the year-ended December 31, 2007 were as follows:

Thousands	Quarter ended March 31, 2008	Quarter ended March 31, 2007	Year-ended Dec. 31, 2007
Medium-Term Notes			
6.31% Series B due 2007	$	$ 20,000	$ 20,000
6.80% Series B due 2007			9,500
	$	$ 20,000	$ 29,500

Cash Flows

Operating Activities

Year-over-year changes in our operating cash flows are primarily affected by net income, gas prices, deferred income taxes, changes in working capital requirements, regulatory deferrals and other cash and non-cash adjustments to operating results. The overall change in cash flow from operating activities for the three months ended March 31, 2008 compared to the same period in 2007 was a decrease of $30.6 million. The major factors contributing to the cash flow changes in the first three months of 2008 compared to the first three months of 2007 are as follows:

- a cash decrease in net income of $4.9 million;
- a cash decrease in deferred gas costs of $10.5 million, primarily related to amortization of prior year s deferrals and higher current gas prices compared to our weighted-average cost of gas;
- a cash increase of $18.6 million resulting from a larger decrease in gas inventory balance in 2008 compared to 2007;
- a cash decrease of $28.2 million resulting from a smaller decrease in accounts receivable and accrued unbilled revenue due to colder weather;

a cash increase of $17.8 million related to an increase in the deferred tax balance in 2008 compared to a small reduction in the first quarter of 2007 due to accelerated tax deductions from bonus depreciation;

a cash decrease of $7.0 million in accounts payable; and

a cash decrease of $11.9 million in accrued interest and taxes payable in 2008 compared to 2007.

Table of Contents

Investing Activities

Cash requirements for investing activities in the first three months of 2008 totaled $22.5 million, up from $19.1 million in the same period of 2007.

The increase was primarily due to $2.7 million of proceeds received from our aircraft leveraged lease investment in 2007. We sold the aircraft investment in April 2008 and will report the sale proceeds in the second quarter of 2008 (see Note 13). Cash requirements for utility plant totaled $19.3 million, up from $18.6 million in the first three months of 2008.

Investments in non-utility property during the first three months of 2008 totaled $1.7 million, down from $3.1 million during the first three months of 2007, due primarily to expansion development at our Mist underground storage, which was completed and placed into service in 2007. In addition, we invested $1.5 million in the Palomar Pipeline project during the first quarter of 2008.

Our utility capital expenditures are expected to total approximately $105 million in 2008, including amounts for a new automated meter reading project. In addition, we expect to spend approximately $15 million to $20 million for non-utility capital expenditures in 2008, including amounts for Gill Ranch and Palomar Pipeline projects.

Financing Activities

Cash used in financing activities in the first three months of 2008 totaled $96.5 million, down from $131.5 million in the same period of 2007. Short-term debt financing consisted of a net decrease of $88.5 in the first three months of 2008, compared to a net decrease of $94.6 million in 2007. Under our common stock repurchase program, no shares were purchased during the first quarter of 2008, compared to 206,700 shares at a total cost of $9.0 million in the first quarter of 2007. No long-term debt was redeemed in the first quarter of 2008.

Pension Funding Status

We make contributions to our qualified defined benefit pension plans based on actuarial assumptions and estimates, tax regulations and funding requirements under federal law. Generally, it is our policy to contribute at least the minimum amount required by Internal Revenue Code regulations and the Employee Retirement Income Security Act of 1974. It is also our intent to contribute additional amounts sufficient on a sound actuarial basis to maintain funding targets and provide for the payment of future benefits under the plans. Our qualified defined pension plans are currently funded at nearly 100 percent of the projected benefit obligation at March 31, 2008. For more information on the funding status of our qualified retirement plans and other postretirement benefits, see Part II, Item 7., Pension Cost and Funding Status of Qualified Retirement Plans, and Part II, Item 8., Note 7, Pension and Other Postretirement Benefits, in the 2007 Form 10-K.

Ratios of Earnings to Fixed Charges

For the three- and 12-months ended March 31, 2008 and the 12-months ended December 31, 2007, our ratios of earnings to fixed charges, computed using the Securities and Exchange Commission method, were 7.86, 3.71 and 3.92, 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. Because a significant part of our business is of a seasonal nature, the ratio for the interim period is not necessarily indicative of the results for a full year.

Contingent Liabilities

Loss contingencies are recorded as liabilities when it is probable that a liability has been incurred and the amount of loss is reasonably estimable in accordance with SFAS No. 5, Accounting for Contingencies, (see Application of Critical Accounting Policies and Estimates Contingencies, above). At March 31, 2008, we had a regulatory asset relating to environmental matters of $63.4 million, which includes $26.1 million of total paid

Table of Contents

expenditures to date, $33.4 million for additional environmental costs expected to be paid in the future and accrued interest of $3.9 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.

Forward-Looking Statements

This report and other presentations made by us from time to time may contain forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended (Exchange Act). Forward-looking statements include statements concerning plans, objectives, goals, strategies, future events or performance, and other statements that are other than statements of historical facts. Our expectations, beliefs and projections are expressed in good faith and are believed to 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, 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 tax laws and policies and 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;
- application of the OPUC 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, pandemic events and other natural phenomena, including earthquakes or other geohazard events;
- unanticipated population growth or decline and changes in market demand caused by changes in demographic or customer consumption patterns;
- competition for retail and wholesale customers;
- market conditions and pricing of natural gas relative to other energy sources;
- the creditworthiness of customers, suppliers and financial derivative counterparties;
- our dependence on a single pipeline transportation provider for natural gas supply;
- 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 relating to business development and investment activities, including the proposed natural gas pipeline project with GTN and the proposed Gill Ranch storage facility;

unanticipated changes that may affect our liquidity or access to capital markets;

our ability to maintain effective internal controls over financial reporting in compliance with Section 404 of the Sarbanes-Oxley Act of 2002;

unanticipated changes in interest or foreign currency exchange rates or in rates of inflation;

economic factors that could cause a severe downturn in certain key industries, thus affecting demand for natural gas;

unanticipated changes in operating expenses and capital expenditures;

Table of Contents

- changes in estimates of potential liabilities relating to environmental contingencies;
- unanticipated changes in future liabilities relating to employee benefit plans, including changes in key assumptions;
- capital market conditions, including their effect on financing costs, the fair value of pension assets and on pension and other postretirement benefit costs;
- 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
- legal and administrative proceedings and settlements.

All subsequent forward-looking statements, whether written or oral and whether made by or on behalf of NW Natural, also are expressly qualified by these cautionary statements. Any forward-looking statement speaks only as of the date on which such statement is made, and 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.

Table of Contents

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to various forms of market risk including commodity supply risk, weather risk, and interest rate risk (see Part II, Item 7A. in the 2007 Form 10-K, Note 7, above, and Part II, Item 1A., Risk Factors, below).

Commodity Price Risk

Natural gas commodity prices are subject to fluctuations due to unpredictable factors including weather, pipeline transportation congestion 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, subject to a regulatory prudence review. At March 31, 2008 and 2007, notional amounts under these financial hedge contracts totaled $170.2 million and $249.8 million, respectively. If all of the commodity-based financial hedge contracts had been settled on March 31, 2008, a gain of about $33.4 million would have been realized and recorded to a deferred regulatory account (see Note 7). We 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 financial hedge contracts settle by October 31, 2009. The $33.4 million unrealized gain is an estimate of future cash flows that are expected to be received as follows: $32.7 million in the next twelve months and $0.7 million during the second twelve months. The amount realized will change based on market prices at the time contract settlements are fixed.

Credit Risk

Credit exposure to financial derivative counterparties. Based on estimated fair value, our credit exposure to financial derivative counterparties relating to commodity hedge contracts was $29.7 million at March 31, 2008. Our Financial Derivatives Policy requires counterparties to have a minimum 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. Some counterparties were recently downgraded but continue to maintain investment grade ratings (see table below). Due to current market conditions and credit concerns, we have tightened our credit requirements and are entering into new derivative transactions only with AA/Aa category rated counterparties or better.

The following table summarizes our credit exposure, based on estimated fair value, and the corresponding counterparty 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, 2008**	**March 31, 2007**	**Dec. 31, 2007**
AAA/Aaa	$ 5,102	$ 3,695	$ (309)
AA/Aa	19,452	3,381	(13,941)
A/A	5,193		123
BBB/Baa			
Total	$ 29,747	$ 7,076	$ (14,127)

Item 4. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

As of March 31, 2008, the principal executive officer and principal financial officer of Northwest Natural Gas Company (NW Natural) have evaluated 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 (the Exchange Act)). Based upon that evaluation, the principal executive officer and principal financial officer of NW Natural have concluded that such disclosure controls and procedures are effective to ensure that information required to be

33

Table of Contents

disclosed by us and included in our reports filed with the Securities and Exchange Commission (Commission) under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the Commission s rules and forms and are also effective to ensure that information required to be disclosed by us and included in our reports filed with or furnished to the Commission under the Exchange Act is accumulated and communicated to our management 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).

In the first quarter of 2008 we implemented an integrated information system for the general ledger, accounts payable, miscellaneous accounts receivable, inventory management and purchasing functions. The new system interfaces with our existing customer information system, payroll, fixed assets and construction work management systems. The integrated information system is designed to:

- automate controls with auditable financial and operational workflow processes;
- automate integration of multiple systems with data entered only once into the system; and
- automate more of the monthly closing process.

Other than as described above, there has been no change in our internal control over financial reporting that occurred during our most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting. The statements contained in Exhibit 31.1 and Exhibit 31.2 should be considered in light of, and read together with, the information set forth in this Item 4(b).

Table of Contents

PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

Litigation

For a discussion of a pending legal proceeding, see Note 10, above.

Item 1A. RISK FACTORS

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, Item 1A. Risk Factors, in our Annual Report on Form 10-K for the year ended December 31, 2007 which could materially affect our business, financial condition or results of operations. The risks described in the 2007 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 adversely affect our financial condition, results of operations or cash flows.

Table of Contents

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, 2008 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
01/01/08 - 01/31/08	1,255	$ 49.90		
02/01/08 - 02/28/08	21,242	$ 45.52		
03/01/08 - 03/31/08	46,177	$ 43.22		
Total	68,674	$ 43.83	2,124,528	$ 16,732,648

(1) During the quarter ended March 31, 2008, 22,337 shares of our common stock were purchased in the open market to meet the requirements of our Dividend Reinvestment and Direct Stock Purchase Plan. In addition, 46,337 shares of our common stock were purchased in the open market during the quarter under equity-based programs. During the three months ended March 31, 2008, no shares of our common stock were accepted as payment for stock option exercises pursuant to our Restated Stock Option Plan.

(2) On May 25, 2000, we announced a program to repurchase up to 2 million shares, or up to $35 million in value, of NW Natural s common stock through a repurchase program that has been extended annually. The purchases are made in the open market or through privately negotiated transactions. In April 2006, the Board increased the authorization from 2 million shares to 2.6 million shares and increased the dollar limit from $35 million to $85 million. In April 2007, the Board increased the authorization from 2.6 million shares to 2.8 million shares and increased the dollar limit from $85 million to $100 million. On April 24, 2008, the Board extended the program through May 31, 2009. During the three months ended March 31, 2008, no shares of our common stock were purchased pursuant to this program. Since the program s inception through March 31, 2008, we have repurchased 2,124,528 shares of common stock at a total cost of $83.3 million.

Item 5. OTHER INFORMATION

On April 23, 2008, NW Natural sold its investment in a Boeing 737-300 aircraft for approximately $6.2 million cash, plus accrued rents. The airplane was purchased in 1987 and leased to Continental Airlines, and currently the airplane continues under lease to Continental. An after-tax gain of approximately $1.1 million will be recognized in the second quarter of 2008.

Item 6. EXHIBITS

See Exhibit Index attached hereto.

Table of Contents

SIGNATURE

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

NORTHWEST NATURAL GAS COMPANY
(Registrant)

Dated: May 2, 2008

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

Table of Contents

NORTHWEST NATURAL GAS COMPANY

EXHIBIT INDEX

To

Quarterly Report on Form 10-Q

For Quarter Ended

March 31, 2008

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