NORTHWEST NATURAL GAS CO
Form 10-Q
May 04, 2007
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2007

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	**(I.R.S. Employer**
incorporation or organization)	**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, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act.

Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨

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, 2007, 26,987,803 shares of the registrant s Common Stock (the only class of Common Stock) were outstanding.

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NORTHWEST NATURAL GAS COMPANY

For the Quarterly Period Ended March 31, 2007

PART I. FINANCIAL INFORMATION

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Statements of Income

(Unaudited)

Thousands, except per share amounts	**Three Months Ended March 31, 2007**	**2006**
Operating revenues:		
Gross operating revenues	$ 394,091	$ 390,391
Less: Cost of sales	245,469	255,399
Revenue taxes	9,614	9,528
Net operating revenues	139,008	125,464
Operating expenses:		
Operations and maintenance	28,839	28,247
General taxes	7,817	7,573
Depreciation and amortization	16,785	15,830
Total operating expenses	53,441	51,650
Income from operations	85,567	73,814
Other income and expense net	538	518
Interest charges net of amounts capitalized	9,567	9,855
Income before income taxes	76,538	64,477
Income tax expense	28,463	23,444
Net income	$ 48,075	$ 41,033
Average common shares outstanding:		
Basic	27,229	27,584
Diluted	27,385	27,632
Earnings per share of common stock:		
Basic	$ 1.77	$ 1.49
Diluted	$ 1.76	$ 1.48

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Balance Sheets

Thousands	**March 31, 2007 (Unaudited)**	**March 31, 2006 (Unaudited)**	**Dec. 31, 2006**
Assets:			
Plant and property:			
Utility plant	$ 1,981,639	$ 1,890,633	$ 1,963,498
Less accumulated depreciation	585,008	547,635	574,093
Utility plant - net	1,396,631	1,342,998	1,389,405
Non-utility property	45,767	40,953	42,652
Less accumulated depreciation and amortization	7,149	6,221	6,916
Non-utility property - net	38,618	34,732	35,736
Total plant and property	1,435,249	1,377,730	1,425,141
Current assets:			
Cash and cash equivalents	5,094	7,522	5,767
Accounts receivable	89,489	97,859	82,070
Accrued unbilled revenue	43,468	47,764	87,548
Allowance for uncollectible accounts	(4,235)	(4,526)	(3,033)
Regulatory assets	10,135	25,556	31,509
Fair value of non-trading derivatives	13,698	16,317	5,109
Inventories:			
Gas	41,828	35,906	68,576
Materials and supplies	9,501	9,808	9,552
Prepayments and other current assets	14,761	57,330	21,695
Total current assets	223,739	293,536	308,793
Investments, deferred charges and other assets:			
Regulatory assets	158,864	100,361	164,771
Fair value of non-trading derivatives	3,734	27,284	1,448
Other investments	48,247	54,432	47,985
Other	8,526	9,102	8,718
Total investments, deferred charges and other assets	219,371	191,179	222,922
Total assets	$ 1,878,359	$ 1,862,445	$ 1,956,856

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Balance Sheets

Thousands	March 31, 2007 (Unaudited)	March 31, 2006 (Unaudited)	Dec. 31, 2006
Capitalization and liabilities:			
Capitalization:			
Common stock	$ 363,519	$ 87,335	$ 371,127
Premium on common stock		296,281	
Earnings invested in the business	269,172	237,205	230,774
Accumulated other comprehensive income (loss)	(2,324)	(1,911)	(2,356)
Total common stock equity	630,367	618,910	599,545
Long-term debt	517,000	501,500	517,000
Total capitalization	1,147,367	1,120,410	1,116,545
Current liabilities:			
Notes payable	5,500	50,400	100,100
Long-term debt due within one year	9,500	28,000	29,500
Accounts payable	92,185	91,185	113,579
Taxes accrued	43,116	25,876	21,230
Interest accrued	11,409	11,623	2,924
Regulatory liabilities	41,888	20,502	11,919
Fair value of non-trading derivatives	9,447	16,739	38,772
Other current and accrued liabilities	22,832	20,432	21,455
Total current liabilities	235,877	264,757	339,479
Deferred credits and other liabilities:			
Deferred income taxes and investment tax credits	207,648	225,047	210,084
Regulatory liabilities	208,333	203,244	202,982
Pension and other postretirement benefit liabilities	54,117	17,693	52,690
Fair value of non-trading derivatives	3,108	3,569	11,031
Other	21,909	27,725	24,045
Total deferred credits and other liabilities	495,115	477,278	500,832
Commitments and contingencies (see Note 10)			
Total capitalization and liabilities	$ 1,878,359	$ 1,862,445	$ 1,956,856

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Statements of Cash Flows

(Unaudited)

Thousands	Three Months Ended March 31, 2007	2006
Operating activities:		
Net income	$ 48,075	$ 41,033
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and amortization	16,785	15,830
Deferred income taxes and investment tax credits	(3,381)	(3,267)
Undistributed earnings from equity investments	78	50
Deferred gas savings (costs) net	14,242	(6,548)
Non-cash expenses related to qualified defined benefit pension plans	1,064	1,441
Deferred environmental costs	(2,800)	(2,014)
Income from life insurance investments	(480)	(1,383)
Other	(2,940)	4,512
Changes in working capital:		
Accounts receivable and accrued unbilled revenue net	37,997	21,766
Inventories of gas, materials and supplies	26,799	40,447
Income taxes receivable		13,234
Prepayments and other current assets	4,280	1,112
Accounts payable	(21,394)	(44,102)
Accrued interest and taxes	30,371	21,856
Other current and accrued liabilities	1,141	(2,231)
Cash provided by operating activities	149,837	101,736
Investing activities:		
Investment in utility plant	(18,609)	(16,997)
Investment in non-utility property	(3,104)	(106)
Proceeds from life insurance		964
Other	2,660	(25)
Cash used in investing activities	(19,053)	(16,164)
Financing activities:		
Common stock issued, net of expenses	1,737	859
Common stock repurchased	(9,017)	(398)
Long-term debt retired	(20,000)	
Change in short-term debt	(94,600)	(76,300)
Cash dividend payments on common stock	(9,677)	(9,516)
Other	100	162
Cash used in financing activities	(131,457)	(85,193)
Increase (decrease) in cash and cash equivalents	(673)	379
Cash and cash equivalents beginning of period	5,767	7,143

Cash and cash equivalents end of period	$	5,094	$	7,522
Supplemental disclosure of cash flow information:				
Interest paid	$	1,101	$	970
Income taxes paid	$	9,000	$	

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Notes to Consolidated Financial Statements

(Unaudited)

1. Basis of Financial Statements

The consolidated financial statements include the accounts of Northwest Natural Gas Company (NW Natural), our regulated gas distribution business and our regulated gas storage business, and its non-regulated wholly-owned subsidiary business, NNG Financial Corporation (Financial Corporation).

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 2006 Annual Report on Form 10-K (2006 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.

Certain prior year balances on our consolidated balance sheet 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

Accounting for Uncertainty in Income Taxes. On January 1, 2007, we adopted Financial Accounting Standards Board (FASB) Interpretation No. 48 (FIN 48), Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109, which provides guidance for the recognition and measurement of a tax position taken or expected to be taken in a tax return. As a result of the implementation of FIN 48, we recognized no change in our recorded assets or liabilities for unrecognized income tax benefits. Based on our analysis of all material tax positions taken, management believes the technical merits of these positions are justified and expects that the full amount of the deductions taken and associated tax benefits will be allowed.

FIN 48 requires the evaluation of a tax position as a two-step process. We must determine whether it is more likely than not that a tax position will be sustained upon examination, including the resolution of any related appeals or litigation processes, based on the technical merits of the position. If the tax position meets the more likely than not recognition threshold, then the tax benefit is measured and recorded at the largest amount that is greater than 50 percent likely of being realized upon ultimate settlement. The re-assessment of our tax positions in accordance with FIN 48 did not result in any material change to our financial condition, results of operations or cash flows. For additional information regarding income taxes, see Part II, Item 7., Application of Critical Accounting Policies and Estimates Accounting for Income Taxes, and Part II, Item 8., Note 8, in the 2006 Form 10-K.

We are subject to U.S. federal income taxes as well as several state and local income taxes. All of our U.S. federal income tax matters audited by the Internal Revenue Service through the 2004 tax year were concluded during 2006 with no material adjustments. Also, substantially all material state and local income tax matters are closed for the years through 2002. Based upon our assessment in connection with the adoption of FIN 48, we do not believe there are any tax positions taken that would not be fully sustained upon audit.

We have also assessed the classification of interest and penalties, if any, related to income tax matters. Pursuant to the application of FIN 48, we have made an accounting election to treat interest and penalties related to income tax matters, if any, as a component of income tax expense rather than other operating expenses.

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Accounting for Certain Hybrid Instruments. In February 2006, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 155, Accounting for Certain Hybrid Instruments, which amended SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, and SFAS No. 140, Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities-a replacement of FASB Statement No. 125. SFAS No. 155 allows financial instruments that have embedded derivatives to be accounted for as a whole if the holder elects to account for the whole instrument on a fair value basis. SFAS No. 155 is effective for all financial instruments acquired or issued after January 1, 2007. The adoption and implementation of SFAS No. 155 did not have an impact on our financial condition, results of operations or cash flows.

Recent Accounting Pronouncements

Fair Value Measurements. In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements, which provides a common definition for the measurement of fair value for use in applying generally accepted accounting principles in the United States of America and in preparing financial statement disclosures. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. We are evaluating the effect of the adoption and implementation of SFAS No. 157, which is not expected to have a material impact on our financial condition, results of operations or cash flows.

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 fiscal years beginning after November 15, 2007. We are evaluating the effect of the adoption and implementation of SFAS No. 159, which is not expected to have a material impact on our financial condition, results of operations or cash flows.

3. Earnings Per Share

Basic earnings per share are computed 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 are calculated as follows:

	Three Months Ended March 31,	
	2007	**2006**
Net income	$ 48,075	$ 41,033
Average common shares outstanding basic	27,229	27,584
Additional shares for stock-based compensation plans	156	48
Average common shares outstanding diluted	27,385	27,632
Earnings per share of common stock basic	$ 1.77	$ 1.49
Earnings per share of common stock diluted	$ 1.76	$ 1.48

For the three month period ended March 31, 2006, 9,000 common shares were excluded from the calculation of diluted earnings per share because the effect would have been antidilutive.

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4. Capital Stock

In connection with an amendment to NW Natural s Restated Articles of Incorporation effective May 31, 2006, the par value of NW Natural s common stock was eliminated. As a result, NW Natural s common stock and premium on common stock account balances are now reflected on the balance sheet as common stock. At March 31, 2007, we had 60,000,000 common shares authorized and 27,109,891 common shares outstanding.

We have in place a Board approved repurchase program for our common stock. During the three months ended March 31, 2007, 206,700 shares of our common stock were purchased pursuant to this program. In April 2007, the Board extended the program through May 31, 2008, further increased the authorization from 2.6 million shares to 2.8 million shares and further increased the dollar limit from $85 million to $100 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 2006 Form 10-K.

In November 2005, the FASB issued FASB Staff Position No. SFAS 123(R)-3 (FSP 123(R)), Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards. FSP 123(R) provides an elective alternative transition method for calculating the pool of excess tax benefits available to absorb tax deficiencies recognized subsequent to the adoption of FAS 123(R). Companies may take up to one year from the effective date of FSP 123(R) to evaluate the available transition alternatives and make a one-time election as to which method to adopt. We have adopted the long-form method for calculating the pool of excess tax benefits.

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, 2007, 42,000 performance-based shares were granted under the LTIP, based on target-level awards, with a weighted-average grant date fair value of $33.29 per share.

Restated Stock Option Plan. In February 2007, we granted 100,600 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	4.7%
Expected life (in years)	6.2
Expected market price volatility factor	17.2%
Expected dividend yield	3.2%
Forfeiture rate	4.36%

As of March 31, 2007, there was $0.9 million of unrecognized compensation cost related to the unvested portion of outstanding stock option awards expected to be recognized over a period extending through 2010.

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6. Long-Term Debt

At March 31, 2007 and 2006 and December 31, 2006, we had outstanding long-term debt as follows:

Thousands	March 31, 2007 (Unaudited)	March 31, 2006 (Unaudited)	Dec. 31, 2006
Medium-Term Notes			
First Mortgage Bonds:			
6.05 % Series B due 2006[1]	$	$ 8,000	$
6.31 % Series B due 2007[2]		20,000	20,000
6.80 % Series B due 2007	9,500	9,500	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
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
	526,500	529,500	546,500
Less long-term debt due within one year	9,500	28,000	29,500
Total long-term debt	$ 517,000	$ 501,500	$ 517,000

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(1) Redeemed at maturity in June 2006.

(2) Redeemed at maturity in March 2007.

7. Use of Financial Derivatives

We enter into forward contracts and other related financial transactions for the purchase of natural gas that qualify as derivative instruments under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended by SFAS No. 138 and SFAS No. 149

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(collectively referred to as SFAS No. 133). We utilize derivative financial instruments primarily to manage commodity prices related to natural gas supply requirements (see Part II, Item 8., Note 11, in the 2006 Form 10-K).

At March 31, 2007 and 2006, 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 included in utility gas costs, pursuant to our regulatory Purchased Gas Adjustment (PGA) deferral mechanism. The estimated fair value of unrealized gains and losses on derivative instruments outstanding, determined using a discounted cash flow model for swaps and indexed-price contracts and a Black-Scholes option pricing model for options, were as follows:

Thousands	March 31, 2007		March 31, 2006		Dec. 31, 2006	
	Current	Non-Current	Current	Non-Current	Current	Non-Current
Fair Value Gain (Loss):						
Natural gas commodity-based derivative instruments:						
Fixed-price financial swaps	$ 6,034	$ 1,536	$ 1,063	$ 25,342	$ (33,965)	$ (6,312)
Fixed-price financial call options	(494)				(678)	
Indexed-price physical supply	(1,258)	(910)	(2,096)	(1,627)	1,115	(3,271)
Physical supply contracts			566			
Foreign currency forward purchases	(31)		45		(135)	
Total	$ 4,251	$ 626	$ (422)	$ 23,715	$ (33,663)	$ (9,583)

In the first quarter of 2007, we realized net losses of $7.6 million from the settlement of fixed-price financial swap contracts which were recorded as increases to the cost of gas, compared to net gains of $17.5 million in the same period of 2006. Realized losses from financial contracts in 2007 were more than offset by lower gas purchase costs from the underlying hedged floating rate physical supply contracts. The foreign currency gain or loss is included in cost of gas at settlement.

As of March 31, 2007, all non-current natural gas commodity-based derivative contracts mature no later than October 31, 2008.

8. Segment Information

Our core business 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 includes asset optimization services under a contract with an independent energy marketing company. The remaining business segment, other, primarily consists of non-regulated investments in alternative energy projects in California, a Boeing 737-300 aircraft leased to Continental Airlines and low-income housing units in Portland, Oregon. Our net investment in the aircraft was reclassified to current assets as of December 31, 2006, with the original lease term expiring in September 2007.

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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
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
Income (loss) from financial investments	480		(78)	402
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
2006				
Net operating revenues	$ 122,344	$ 3,079	$ 41	$ 125,464
Depreciation and amortization	15,610	220		15,830
Income from operations	71,122	2,684	8	73,814
Income (loss) from financial investments	1,383		(50)	1,333
Net income	39,463	1,449	121	41,033
Total assets at March 31, 2006	$ 1,815,343	$ 35,533	$ 11,569	$ 1,862,445

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	2007	2006	2007	2006
Service cost	$ 2,159	$ 1,961	$ 148	$ 137
Interest cost	3,995	3,758	320	283
Expected return on plan assets	(4,636)	(4,403)		
Amortization of loss	539	916	1	
Amortization of prior service cost	245	245	49	49
Amortization of transition obligation			103	103
Net periodic benefit cost	2,302	2,477	621	572
Amount allocated to construction	(515)	(700)	(202)	(187)
Net amount charged to expense	$ 1,787	$ 1,777	$ 419	$ 385

See Part II, Item 8., Note 7, in the 2006 Form 10-K for more information about our pension and other postretirement benefit plans.

Employer Contributions

During the three months ended March 31, 2007, we did not make and were not required to make cash contributions to our qualified non-contributory defined benefit 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 2006 Form 10-K for a discussion of future payments.

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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 2006 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 the first quarter of 2007, the estimated liability for this site increased $0.5 million related to estimated liabilities for the development of proposed studies of in-water source control and completion of those studies. We have accrued a liability of $6.2 million at March 31, 2007 for the Gasco site, which is at the low end of the range 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 is now 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 portion of this site. See Regulatory and Insurance Recovery for Environmental Matters, below.

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 site and the Siltronic site. 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). Current information is not sufficient to reasonably estimate additional liabilities, if any, or the range of potential liabilities, for environmental remediation and monitoring after the RI/FS work plan is completed, except for the early action removal of a tar deposit in the river sediments discussed below.

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, which was approved by the EPA. The total cost of removal, including technical work, oversight, consultant fees, legal fees and ongoing monitoring, was about $10.3 million. To date we have paid $9.3 million on work related to the removal of the tar deposit with a remaining liability estimate of $1.0 million.

Central Gas Storage Tanks. In September 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, or through historic gas handling practices. In the early 1990s, we excavated waste piles and much of the contaminated

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surface soils and removed accessible waste from some of the abandoned piping. We initially recorded a small accrual in September 2006 for the ODEQ site assessment and legal and technical costs to investigate and determine the appropriate action needed to be taken, if any. In early 2007, we received notice that the 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. Additional costs are not currently estimable. We received regulatory authorization from the OPUC for the deferral of environmental costs related to this site (see Regulatory and Insurance Recovery for Environmental Matters, below).

Regulatory and Insurance Recovery for Environmental Matters. In May 2003, the OPUC approved our request for deferral of environmental costs associated with specific sites, including the Gasco, Siltronic and Portland Harbor sites. The authorization, which was extended through January 2008 and expanded to include the Oregon Steel Mills site (discussed below) and the Central Service Center site (discussed above), allows us to defer and seek recovery of unreimbursed environmental costs in a future general rate case. Beginning in 2006, the OPUC authorized us to accrue interest on deferred 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.

On a cumulative basis, we have recognized a total of $33.2 million for environmental costs, including legal, investigation, monitoring and remediation costs. Of this total, $26.8 million has been spent to date and $6.4 million is reported as an outstanding liability. At March 31, 2007, we had a regulatory asset of $28.3 million, which includes $21.9 million for paid expenditures and interest plus $6.4 million for additional environmental accruals expected to be paid in the future. We believe the recovery of these deferred charges is probable through the regulatory process. We also have an insurance receivable of $1.1 million, which is not included in the regulatory asset amount. We intend to pursue recovery of this insurance receivable and environmental regulatory deferrals from 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.

The following table summarizes the regulatory assets and accrued liabilities relating to environmental matters at March 31, 2007 and 2006 and December 31, 2006:

	Non-Current Regulatory Assets			Non-Current Liabilities		
	March 31,		Dec. 31,	March 31,		Dec. 31,
Millions	**2007**	**2006**	**2006**	**2007**	**2006**	**2006**
Gasco site	$ 10.8	$ 3.4	$ 10.3	$ 6.2	$ 1.0	$ 6.6
Siltronic site	0.5	0.3	0.5	0.1		0.1
Portland Harbor site	16.8	15.2	16.8	1.7	3.5	3.1
Oregon Steel Mills site	0.2	0.2	0.2	0.2	0.2	0.2
Total	$ 28.3	$ 19.1	$ 27.8	$ 8.2	$ 4.7	$ 10.0

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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 matters 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.

Independent Backhoe Operator Action. Since May 2004, five lawsuits have been filed against NW Natural by independent backhoe operators who performed backhoe services for NW Natural under contract. These five lawsuits have been consolidated into one case, in which 10 plaintiffs remain (*Law and Zuehlke, et. al. v. Northwest Natural Gas Co.,* CV-04-728-KI, United States District Court, District of Oregon). Plaintiffs allege violation of the Fair Labor Standards Act for failure to pay overtime and also assert state wage and hour claims. Plaintiffs claim that they should have been considered employees, and seek overtime wages and interest in amounts to be determined, liquidated damages equal to the overtime award, civil penalties and attorneys fees and costs. Additionally, plaintiffs alleged that the failure to classify them as employees constituted a breach of contract under and with respect to certain employee benefits plans, programs and agreements. Plaintiffs sought an unspecified amount of damages for the value of what they would have received under these employee benefit plans if they had been classified as employees. In May 2007, the District Court granted our motion for Summary Judgment on plaintiffs breach of contract and benefits claims. The ruling leaves only the overtime and wage and hour claims in the case. Our estimate of the remaining liability, if any, is not material. We therefore do not expect the outcome of this litigation to 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 Port s 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 received regulatory authorization from the OPUC for the deferral of environmental costs related to this site (see Regulatory and Insurance Recovery for Environmental Matters, above). 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.

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 $2.3 million at March 31, 2007, which is related to employee benefit plan liabilities. The following table provides a reconciliation of net income to total comprehensive income for the three months ended March 31, 2007 and 2006.

	Three Months Ended March 31,	
Thousands	**2007**	**2006**
Net income	$ 48,075	$ 41,033
Amortization of employee benefit plan liability, net of tax	32	
Total comprehensive income	$ 48,107	$ 41,033

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

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

The following is management s assessment of Northwest Natural Gas Company s 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, 2007 and 2006. 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 Northwest Natural Gas Company, which principally consists of our regulated local gas distribution business, our regulated gas storage business, and our other non-regulated businesses, which includes our wholly-owned subsidiary business, NNG Financial Corporation (Financial Corporation). 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 segment (gas storage) and our other non-regulated activities (other) (see Note 8).

Certain prior year balances on our consolidated balance sheet 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.

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 2006 Form 10-K).

Executive Summary

Our strategy in 2007 is to remain focused on profitably growing our regulated gas utility and gas storage businesses. The gas utility is our largest business segment with approximately 98 percent of consolidated total assets, which contributed 90 percent of consolidated net income in 2006. Factors critical to the success of the utility include maintaining a safe and reliable distribution system, acquiring an adequate supply of gas, providing distribution services at a competitive price, and being able to recover the operating and capital costs of the utility in the rates charged to customers. The utility is regulated by two state commissions, the Oregon Public Utility Commission (OPUC) and the Washington Utilities and Transportation Commission (WUTC).

Our gas storage segment represents approximately 2 percent of consolidated total assets, which contributed 9 percent of consolidated net income in 2006. This business unit primarily provides firm and interruptible gas storage at our Mist underground storage facility to large interstate and intrastate customers using storage and related transportation capacity that is in excess of our utility s core (residential, commercial and industrial firm) customer requirements. Asset optimization is also part of our gas storage segment, with optimization services provided for the utility under an agreement with an independent energy marketing company. Factors critical to the success of our gas storage business segment include the ability to: develop additional storage capacity at competitive market prices; plan for the replacement of capacity that is expected to be recalled by the utility to serve its core customers in the future; and obtain timely and reasonable rate recovery for operating and capital costs.

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Highlights from the first quarter of 2007 include:

- Net income increased 17 percent during the first quarter of 2007 compared to the same period in 2006, from $41.0 million to $48.1 million;
- Solid growth in net operating revenues from our regulated utility and gas storage businesses were major drivers to increased earnings in the first quarter of 2007, with an 11 percent increase in net operating revenues at both our utility and gas storage;
- Operations and maintenance expense increased 2 percent in the first quarter of 2007, including incremental costs for seasonal employees and employee bonus accruals tied to improved financial results, which were largely offset by cost reductions from business process redesign initiatives that we began implementing in 2006;
- Cash flow from operations increased 47 percent to $149.8 million, reflecting stronger operating results and an increase in cash flows from lower gas costs; and
- Total debt decreased by $114.6 million in the first quarter of 2007, reflecting a $20 million redemption of long-term debt at maturity and a $94.6 million decrease in notes payable.

Issues, Challenges and Performance Measures

There are a number of issues and challenges that affect our operations and financial performance. The most significant challenge we face in the near term continues to be managing the utility business in a period of high gas prices, increased demand and increased market volatility. Our gas acquisition strategy has been to secure sufficient supplies of natural gas to meet the needs of our utility s firm customers, but equally important is our strategy to hedge gas prices for a significant portion of our annual purchase requirements based upon the market outlook and our core utility s load forecast. In 2005, we hedged about 90 percent of our winter supplies prior to when the hurricanes hit, which helped us avoid much of the spike in gas prices that fall and winter. In 2006, we hedged at a lower level, and as spot gas prices fell later in the year we were able to take advantage of the lower gas costs, resulting in commodity savings shared by our utility customers and shareholders. Currently, we expect energy prices to remain slightly higher than in the past few years, with higher gas prices already reflected in our customers bills for the current Purchased Gas Adjustment (PGA) period which extends through October 2007. We believe we have sufficient supplies of natural gas under contract to meet the needs of our firm customers, but further price increases could change our earnings outlook and our competitive advantage. If high gas prices persist, it could significantly affect our ability to add residential and commercial customers and could result in industrial customers shifting their businesses energy needs to alternative fuel sources. To address these competitive issues, we are continually developing new gas acquisition strategies to manage gas prices and meet market demands, and we are working on initiatives intended to improve operational efficiencies throughout the company through a comprehensive business process redesign effort (see Part II, Item 7., Executive Summary Issues, Challenges and Performance Measures, in the 2006 Form 10-K).

Strategic Opportunities

Business Process Redesign. During 2006, we initiated a project to evaluate our business processes and costs against our peers and to redesign those processes where long-term efficiencies could be gained. We identified a number of areas where we could restructure our business to gain efficiencies, including more centralization, an increased focus on process orientation, and more standardized processes. As an example, in 2007 we will be developing the first phase of a new enterprise resource planning system to support our new business processes in a more standardized and automated environment. For more information regarding our redesign efforts, see Part II, Item 7., Strategic Opportunities, in the 2006 Form 10-K.

Pipeline Diversity. In September 2006, we announced that we were evaluating making an investment in a potential pipeline project that would connect TransCanada s Gas Transmission Northwest (GTN) interstate transmission line to our local gas distribution system. We are continuing to evaluate the project, and a decision on whether to proceed with the development planning and permitting of the

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pipeline is expected to be made later this year. No material contractual obligations related to the pipeline have been incurred as of March 31, 2007. If constructed, we expect commercial operation of the pipeline to commence in 2011.

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 2006 Form 10-K). There have been no material changes to the information provided in the 2006 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.

Earnings and Dividends

Net income was $48.1 million, or $1.76 a share, for the three months ended March 31, 2007, compared to $41.0 million, or $1.48 a share, for the same period last year.

First quarter of 2007 compared to 2006:

Positive factors contributing to increased earnings were:

- increased utility volumes and net operating revenues (margin) from sales to residential and commercial customers due to 2.8 percent customer growth, plus weather that was 2 percent colder than the first quarter of 2006 (see Results of Operations Comparison of Gas Distribution Operations, below);

- increased margin from regulatory sharing of gas cost savings, from $1.8 million in the first quarter of 2006 to $9.8 million in 2007, and a $2.7 million gain from the reversal of a temporary loss taken in the fourth quarter of 2006 related to derivative contracts that settle in 2007; and

- decreased interest costs due to lower short-term debt balances.

Partially offsetting the above positive factors were:

- increased depreciation expenses related to higher utility plant in service, which were partially offset by revenue increases related to cost recovery of pipeline integrity and bare steel capital expenditures that are tracked into rates on an annual basis through the PGA filings in Oregon; and

- increased income tax expense related to higher taxable income.

Dividends paid on our common stock were 35.5 cents a share and 34.5 cents a share in the three month periods ended March 31, 2007 and 2006, respectively. In April 2007, the Board of Directors declared a quarterly dividend on our common stock of 35.5 cents per share payable May 15, 2007 to shareholders of record on April 30, 2007. The current indicated annual dividend rate is $1.42 per share.

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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 OPUC and the WUTC. Typically, about 90 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 2006 Form 10-K.

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At March 31, 2007 and 2006, the amounts deferred as regulatory assets and liabilities were as follows:

	Current		
	March 31,		Dec. 31,
Thousands	2007	2006	2006
Regulatory assets:			
Gas costs receivable	$	$ 8,747	$
Unrealized loss on non-trading derivatives[1]	9,233	16,096	30,798
Other	902	713	711
Total regulatory assets	$ 10,135	$ 25,556	$ 31,509
Regulatory liabilities:			
Gas costs payable	$ 17,666	$	$ 737
Unrealized gain on non-trading derivatives[1]	13,698	16,317	
Other	10,524	4,185	11,182
Total regulatory liabilities	$ 41,888	$ 20,502	$ 11,919

	Non-Current		
	March 31,		Dec. 31,
Thousands	2007	2006	2006
Regulatory assets:			
Gas costs receivable	$	$ 4,775	$
Unrealized loss on non-trading derivatives[1]	3,108	3,569	9,584
Income tax asset	68,086	66,757	67,141
Pension and other postretirement benefit obligations[2]	53,540		54,425
Environmental costs paid[3]	21,912	14,453	19,113
Environmental costs accrued but not yet paid[3]	6,462	4,743	8,760
Other	5,756	6,064	5,748
Total regulatory assets	$ 158,864	$ 100,361	$ 164,771
Regulatory liabilities:			
Gas costs payable	$ 10,354	$	$ 13,041
Unrealized gain on non-trading derivatives[1]	3,734	27,285	
Accrued asset removal costs	191,886	173,936	187,422
Other	2,359	2,023	2,519
Total regulatory liabilities	$ 208,333	$ 203,244	$ 202,982

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 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 from the 2003 Oregon and 2004 Washington general rate cases (see Part II, Item 8., Note 7 in the 2006 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, the application of temporary rate adjustments to amortize balances in deferred regulatory accounts and the removal of temporary rate adjustments effective for the previous year. 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 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 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 investigation is expected to be completed in early 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. In 2006, the threshold after adjustment was 13.44 percent. We do not expect that any amounts will be required to be refunded to customers as a result of the 2006 earnings test, which will be reviewed by the OPUC during the second quarter of 2007. In Washington, we are not subject to an annual excess earnings test and 100 percent of all prudently incurred gas costs are passed through into customer 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. On March 28, 2007, we filed a draft IRP with the WUTC and are required to file a final IRP with the OPUC by August 15, 2007.

Interstate Pipeline Rate Cases

On June 30, 2006, the two interstate pipeline companies that provide natural gas transportation to our distribution system filed for general rate increases with the Federal Energy Regulatory Commission (FERC). Changes in interstate pipeline transportation charges are subject to our PGA mechanism and are 100 percent passed-through to customers in both Oregon and Washington. Both of the filed general rate increases were reflected in our 2006 PGA filings. In March 2007, FERC approved Northwest Pipeline s settlement proposal, resulting in a lower than expected increase to our pipeline transportation rates. Amounts currently being collected from our customers in excess of this amount will be deferred and returned to customers, which will reduce gross revenues and costs of sales but will have no impact on our net results of operations. See Part II, Item 7., Results of Operations Regulatory Matters Interstate Pipeline Rate Cases, in the 2006 Form 10-K.

Utility Regulation Legislation

Under Oregon regulatory law, we are required to file a report in October each year that calculates the difference between the amount of income taxes paid to governmental entities compared to the amount of taxes we collected in rates in the previous year. For more information regarding this requirement, see Part II, Item 7., Results of Operations Regulatory Matters Utility Regulation Legislation, in the 2006 Form 10-K.

Based on our assessment of the rules developed to implement the law, we estimate that our 2007 Tax Report for the 2006 tax year will reflect a surcharge of about $1.6 million; that is, the amount of income taxes paid to government entities will exceed the amount of taxes the utility collected in rates, thus creating a rate adjustment that requires a reimbursement from customers. It is anticipated that any

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amounts due from customers for the 2006 tax year would not be realized until after June 1, 2008, pending a review by the OPUC. We have estimated that our 2008 Tax Report for the 2007 tax year will also reflect a surcharge. Based on results through March 31, 2007, we estimate the surcharge related to our first quarter to be about $2.8 million. We have determined that the recognition of this regulatory surcharge is uncertain because the OPUC has not completed its review of how the final rules will be applied to our 2006 and 2007 financial results, our request for a Private Letter Ruling from the Internal Revenue Service is not complete and there are ongoing efforts in the current Oregon legislative session that could potentially change certain provisions of the law. Due to the regulatory uncertainty, recovery in rates of the 2006 and estimated 2007 surcharge is not considered probable at this time and these amounts have been reserved. Given our current corporate structure and level of non-utility investments and activities, we expect that ongoing compliance with this law, as currently interpreted, will not have a material adverse effect on our financial condition, results of operations or cash flows.

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Comparison of Gas Distribution Operations

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

Thousands, except degree day and customer data	Three months ended March 31, 2007	2006	Favorable/ (Unfavorable)
Utility volumes therms:			
Residential sales	162,897	159,312	3,585
Commercial sales	96,804	95,325	1,479
Industrial firm sales	15,917	24,038	(8,121)
Industrial firm transportation	43,471	29,742	13,729
Industrial interruptible sales	25,664	42,564	(16,900)
Industrial interruptible transportation	67,738	56,955	10,783
Total utility volumes sold and delivered	412,491	407,936	4,555
Utility operating revenues dollars:			
Residential sales	$ 227,138	$ 214,314	$ 12,824
Commercial sales	118,042	113,047	4,995
Industrial firm sales	16,655	23,176	(6,521)
Industrial firm transportation	1,498	948	550
Industrial interruptible sales	22,131	35,352	(13,221)
Industrial interruptible transportation	2,093	1,859	234
Other revenues	3,068	(1,440)	4,508
Total utility operating revenues	390,625	387,256	3,369
Cost of gas sold	245,462	255,384	9,922
Revenue taxes	9,614	9,528	(86)
Utility net operating revenues (margin)	$ 135,549	$ 122,344	$ 13,205
Utility margin:			
Residential sales	$ 81,036	$ 78,348	$ 2,688
Commercial sales	32,338	31,777	561
Industrial sales and transportation	8,379	8,486	(107)
Miscellaneous revenues	1,639	1,503	136
Other margin adjustments	10,951	1,440	9,511
Margin before regulatory adjustments	134,343	121,554	12,789
Weather normalization mechanism	108	1,842	(1,734)
Decoupling mechanism	1,098	(1,052)	2,150
Utility margin	$ 135,549	$ 122,344	$ 13,205
Customers end of period:			
Residential customers	579,746	563,178	16,568
Commercial customers	60,987	60,175	812
Industrial customers	953	944	9
Total number of customers end of period	641,686	624,297	17,389

Actual degree days	1,852	1,814
Percent colder (warmer) than average [1]	(1)%	(3)%

[1] Average weather represents the 25-year average degree days, as set in our last Oregon general rate case.

Certain amounts in prior years have been reclassified to conform to the current year presentation. These reclassifications had no impact on prior year results of operations.

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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 order to offset the potential volatility in utility earnings caused by weather and declining consumption due to conservation, we obtained OPUC approval of a conservation tariff that adjusts margin up or down based on changes in residential and commercial customer consumption and a weather normalization mechanism that adjusts customer bills, and our margin, based on above- or below-average temperatures during the winter heating season (see Regulatory Developments Rate Mechanisms, above, and Part II, Item 7., Results of Operations Regulatory Matters Rate Mechanisms, in the 2006 Form 10-K).

Total utility volumes sold and delivered in the first quarter this year increased by 1 percent over last year, while total utility margin increased by 11 percent. The volume increase in the quarter was due mainly to residential and commercial customer growth, which remained strong with a net increase of 17,389 customers since March 31, 2006, or an annual growth rate of 2.8 percent. Our growth rate remains well above the national average for local gas distribution companies, despite recent economic conditions that have moderately decreased the level of new construction in our service territory. In the three years ended December 31, 2006, more than 58,400 customers were added, representing an average annual growth rate of 3.4 percent. The margin increase in the quarter was driven primarily by a decrease in the cost of gas (see Cost of Gas Sold, below).

Residential and Commercial Sales

Residential and commercial sales markets are impacted by seasonal weather patterns, energy prices, competition from alternative energy sources and economic conditions in our service areas. Typically, 80 percent or more of our annual utility operating revenues are derived from gas sales to weather-sensitive residential and commercial customers. Although variations in temperatures between periods will affect volumes of gas sold to these customers, the effect on margin and net income is significantly reduced due to the weather normalization mechanism in Oregon where about 90 percent of our customers are served. Approximately 10 percent of our eligible Oregon customers have opted out of 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. See the table above for the adjustments to utility margin revenues from the weather normalization and decoupling mechanisms for the quarters ended March 31, 2007 and 2006.

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

- sales volumes were 2 percent higher as a result of customer growth and 2 percent colder weather than last year; and
- operating revenues were 5 percent higher due to higher sales volumes and higher billing rates, which reflect the higher gas costs in the PGA effective November 1, 2006 (see Part II, Item 7., Regulatory Matters Rate Mechanisms Purchased Gas Adjustment, in the 2006 Form 10-K).

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. Amounts reported as unbilled revenues reflect the increase or decrease in the balance of accrued unbilled revenues compared to the prior period 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, 2007, accrued unbilled revenue was $43.5 million, compared to $47.8 million at March 31, 2006, with the decrease primarily reflecting warmer weather toward the end of the first quarter of 2007 as compared to 2006. Accrued unbilled revenue was $87.5 million at December 31, 2006.

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Industrial Sales and Transportation

Total volumes delivered to industrial sales and transportation customers were down 0.5 million therms, or less than 1 percent, in the first quarter of 2007 as compared to the same period in 2006. Utility operating revenues related to these customers were down $19.0 million, or 31 percent, over last year. The lower operating revenues primarily reflect the transfer of customers from sales service last year to transportation service this year, with the cost of gas sold a larger component in operating revenues last year as compared to this year. On a year-to-year basis, margin is a better indication of performance for the industrial sector due to the shift from sales to transportation. In 2007, utility margin decreased $0.1 million, or about 1 percent, compared to 2006 on lower volumes delivered.

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 2006 Form 10-K). Other revenues were $3.1 million in the first quarter of 2007, compared to a net expense of $1.4 million in the first quarter of 2006, primarily due to a change in customer fees and decoupling regulatory deferrals and amortization.

Cost of Gas Sold

Natural gas commodity prices have risen significantly in recent years. The effects of higher commodity prices and price volatility on core utility customers are mitigated, in part, through our use of underground storage facilities, fixed-price commodity hedge contracts and short term sales of excess gas supply and transportation capacity to off-system customers in periods when core utility customers do not require the full amount of contract gas supplies or firm pipeline capacity.

The total cost of gas sold was $245.5 million in the first quarter of 2007, a decrease of $9.9 million or 4 percent compared to the first quarter of 2006. 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.

Under the PGA tariff in Oregon, our net income is affected by a sharing mechanism based on increases or decreases in purchased gas costs as compared to estimated gas costs included in customer rates (see Part II, Item 7., Results of Operations Regulatory Matters Rate Mechanisms Purchased Gas Adjustment, in the 2006 Form 10-K). In the first quarter of 2007, our share of gas cost savings contributed $9.8 million to margin, compared to net savings and a contribution to margin of $1.8 million in the comparable 2006 period. The net benefit to utility customers from aggregate gas cost savings amounted to $21.7 million for the three months ended March 31, 2007.

We use a natural gas commodity-price hedge program under the terms of our Financial Derivatives Policy to help manage our exposure to floating price gas purchase contracts (see Part II, Item 7., Application of Critical Accounting Policies and Estimates Accounting for Derivative Instruments and Hedging Activities, in the 2006 Form 10-K, and Note 7, above). We realized net losses of $7.6 million from our financial hedges in the first quarter of 2007, compared to gains of $17.5 million in the same period of 2006. Gains and losses from the financial hedging of utility gas purchases generally are included in cost of gas, which are factored into our PGA deferrals and annual rate changes, but 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. We recorded a $2.7 million credit to the cost of gas in the first quarter of 2007 related to the reversal of an unrealized loss on financial derivative contracts that were entered into during the fourth quarter of 2006, which was after the 2006 PGA filing (see Part II, Item 7., Application of Critical

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Accounting Policies and Estimates Accounting for Derivative Instruments and Hedging Activities, in the 2006 Form 10-K). The fourth quarter 2006 temporary loss was largely reversed in the first quarter of 2007 as a majority of these derivative contracts settled.

Business Segments Other than Gas Distribution Operations

Gas Storage

Net income from our gas storage business segment in the three months ended March 31, 2007 was $1.8 million after regulatory sharing and income taxes, or 7 cents per share, compared to net income of $1.4 million, or 5 cents per share, in the three months ended March 31, 2006. 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 2006 Form 10-K).

Third-party optimization is provided pursuant to a contract with an independent energy marketing company, which assists in the optimization of the value of our assets primarily through the use of commodity transactions. In Oregon, we retain 80 percent of the pre-tax income from interstate storage services and optimization activities when the costs of the capacity used have not been included in utility rates, or 33 percent of the pre-tax income from such 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 interstate storage services and third-party optimization.

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 a leveraged aircraft lease (see Part II, Item 8., Note 2, Consolidated Subsidiary Operations and Segment Information, in the 2006 Form 10-K). Operating results from this segment for the three months ended March 31, 2007 were net income of $0.2 million, compared to $0.1 million for the three months ended March 31, 2006.

Our net investment balance in Financial Corporation at March 31, 2007 and 2006 was $2.7 million and $3.6 million, respectively. The $0.9 million decrease primarily reflects lower cash investments due to a cash dividend paid to NW Natural in the second quarter of 2006. Our net investment balance in the leveraged aircraft lease at March 31, 2007 and 2006 was $4.7 million and $7.0 million, respectively, with the decrease primarily due to the receipt in March 2007 of the final payment due under the terms of the lease agreement.

Operating Expenses

Operations and Maintenance

Operations and maintenance expenses in the first quarter of 2007 were $28.8 million, representing a $0.6 million, or 2 percent, increase over the first quarter of 2006. The following summarizes the major factors that contributed to the increase in operations and maintenance expense:

- a $0.5 million increase in other contract work primarily due to seasonal staffing for the call center; and
- a $0.5 million increase in benefit expenses for non-qualified pension plan costs and for stock-based compensation;
- offset, in part, by a $0.4 million decrease in bad debt expense due to improved collection results.

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General Taxes

General taxes, which are principally comprised of property taxes, payroll taxes and regulatory fees, increased $0.2 million, or 3 percent, in the three months ended March 31, 2007 over the same period in 2006. Regulatory fees increased $0.2 million, or 11 percent, in the first quarter of 2007 compared to the first quarter of 2006 reflecting increased gross operating revenues. The change in property and payroll taxes was negligible in the first quarter of 2007 compared to the first quarter of 2006.

Depreciation and Amortization

Depreciation and amortization expense increased by $1.0 million, or 6 percent, in the three-month period ended March 31, 2007, compared to the same period in 2006. The increased expense reflects ongoing capital expenditures for utility plant that were made primarily to meet continuing customer growth and to upgrade operating facilities.

Other Income and Expense   Net

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

Thousands	Three Months Ended March 31, 2007	2006
Other income and expense net:		
Gains from company-owned life insurance	$ 480	$ 1,383
Interest income	152	84
Other non-operating expense	(274)	(603)
Net interest income (expense) on deferred regulatory accounts	258	(296)
Loss from equity investments of Financial Corporation	(78)	(50)
Total other income and expense net	$ 538	$ 518

The negligible increase in other income and expense   net in the first quarter of 2007 compared to the same period in 2006 was primarily due to interest on deferred regulatory accounts that were higher because of increases in deferred environmental costs, and a decrease in other non-operating expenses, largely offset by reduced life insurance benefits from company-owned policies.

Interest Charges   Net of Amounts Capitalized

Interest charges   net of amounts capitalized decreased $0.3 million, or 3 percent, in the quarter ended March 31, 2007 compared to the same period in 2006, primarily due to lower balances of total debt outstanding resulting from cash flows tied to gas cost savings.

Income Taxes

Income tax expense totaled $28.5 million in the first quarter of 2007 compared to $23.4 million in the first quarter of 2006. The effective tax rate was 37.2 percent in the first quarter of 2007 compared to 36.4 percent in the first quarter of 2006. The higher income tax expense in 2007 is due primarily to pre-tax book income of $76.5 million compared to $64.5 million for the same period in 2006, resulting in higher income tax expenses. The increase in effective tax rate in 2007 was largely due to a decrease in tax benefits from a $0.9 million decrease in non-taxable gains on life insurance.

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Financial Condition

Capital Structure

Our 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, 2007 and 2006 and at December 31, 2006, including short-term debt, was as follows:

	March 31,		Dec. 31,
	2007	2006	2006
Common stock equity	54.2%	51.6%	48.1%
Long-term debt	44.5%	41.8%	41.5%
Short-term debt, including current maturities of long-term debt	1.3%	6.6%	10.4%
Total	100.0%	100.0%	100.0%

The common stock equity percentages in March 2007 and March 2006 were higher as compared to December 2006 primarily due to seasonal earnings and cash flows that reduced the combined long-term and short-term debt percentages.

In April 2007, the Board authorized an increase to the share repurchase program of our common stock, now aggregating up to 2.8 million shares, or up to $100 million in value, from the previous authorized levels of up to 2.6 million shares or up to $85 million in value. Purchases under this program are made in the open market or through privately negotiated transactions. 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, 2007, we had $5.1 million of cash and cash equivalents compared to $7.5 million at March 31, 2006 and $5.8 million at December 31, 2006. Short-term liquidity is provided by cash from operations and from the sale of commercial paper notes, which are supported by committed bank lines of credit totaling $200 million and are available through September 30, 2010 (see Lines of Credit, below, and Part II, Item 8., Note 6, in the 2006 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.

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.

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Contractual Obligations

Since December 31, 2006, our estimated future contractual obligations have increased by about $10 million primarily due to contracts to outsource a portion of our construction work, including mains and services and locating services as well as for consulting on our low income energy efficiency programs, which are all in the ordinary course of our business. Our contractual obligations at December 31, 2006 are described in Part II, Item 7., Financial Condition Liquidity and Capital Resources Contractual Obligations, in the 2006 Form 10-K.

Commercial Paper

Our primary source of short-term funds is from the sale of commercial paper notes payable. In addition to issuing commercial paper to meet seasonal working capital requirements, including the financing of gas purchases 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 outstanding commercial paper, which is sold through two commercial banks under an issuing and paying agency agreement, is supported by committed bank lines of credit (see Lines of Credit, below, and Part II, Item 8., Note 6, in the 2006 Form 10-K). We had $5.5 million in commercial paper notes outstanding at March 31, 2007, compared to $50.4 million outstanding at March 31, 2006 and $100.1 million outstanding at December 31, 2006. 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, and this year s outstanding balances were lower than last year primarily due to the gas cost savings discussed above in Results of Operations Comparison of Gas Distribution Operations Cost of Gas Sold.

Lines of Credit

We have agreements for unsecured lines of credit totaling $200 million with five commercial banks. The bank lines of credit (bank lines) are available and committed for a term of five years, from October 1, 2005 to September 30, 2010. There were no outstanding balances on these bank lines at March 31, 2007 or 2006, or at December 31, 2006.

The bank lines require us to maintain an indebtedness to total capitalization ratio of 65 percent or less. Failure to comply with this covenant would entitle the banks to terminate their lending commitments and to accelerate the maturity of any amounts outstanding. We were in compliance with this covenant at March 31, 2007 and 2006 and at December 31, 2006.

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	Stable

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.

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Redemptions of Long-Term Debt

In March 2007, we redeemed $20.0 million of secured 6.31% Series B Medium Term Notes at maturity. In June 2006, we redeemed $8.0 million of secured 6.05% Series B Medium-Term Notes at maturity.

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, 2007 compared to the same period in 2006 was an increase of $48.1 million. The major factors contributing to the cash flow changes in the first three months of 2007 compared to the first three months of 2006 are as follows:

- an increase in net income added $7.0 million to cash flow;
- deferred gas costs, primarily related to gas cost savings realized in the first quarter of 2007, increased cash by $20.8 million with the regulatory liability account increasing in the first quarter of 2007 compared to the regulatory receivable increasing in the first quarter of 2006; this current liability balance is expected to reverse when those costs are reflected in utility rates under our PGA tariff to be effective later in 2007;
- a decrease of $13.6 million in cash resulting from an increase in gas inventory balance in 2007 compared to 2006;
- an increase of $16.1 million due to a decrease in accounts receivable and accrued unbilled revenue reflecting improvement in the collection of year-end balances between 2007 and 2006;
- a decrease of $13.2 million in 2007 compared to 2006 due to the realization of income taxes receivable in 2006;
- a reduction in accounts payable increased cash by $22.7 million in 2007 primarily due to lower gas prices around year end 2006; and
- an increase in accrued interest and taxes payable increased cash flow by $8.5 million in 2007 compared to 2006.

Investing Activities

Cash requirements for investing activities in the first three months of 2007 totaled $19.1 million, up from $16.2 million in the same period of 2006. Cash requirements for utility plant totaled $18.6 million, up from $17.0 million in the first three months of 2007, with the increase primarily related to our automated meter reading project. This increase was partially offset by lower capital spending on new residential and commercial services.

Investments in non-utility property during the first three months of 2007 totaled $3.1 million, up from $0.1 million during the first three months of 2006, due primarily to amounts related to the capital improvements and expansion development at our gas storage facilities in 2007. In 2007, we also received a $2.7 million payment due under the airplane leveraged lease agreement.

Our utility and non utility capital expenditures are now expected to total about $120 million in 2007, which includes estimates for an enterprise resource planning system and additional gas storage related capital expenditures.

Financing Activities

Cash used in financing activities in the first three months of 2007 totaled $131.5 million, up from $85.2 million in the same period of 2006. The primary factors contributing to the $46.3 million increase were differences in debt financings and increased common stock repurchase activity. Debt financing consisted of a net decrease of $114.6 million in short-term and long-term debt outstanding in the first three months of 2007, compared to a net decrease of $76.3 million in 2006. Under our common stock repurchase program, we purchased 206,700 shares at a total cost of $9.0 million in the first quarter of 2007, compared to 11,700 shares at a total cost of $0.4 million in the first quarter of 2006.

Pension Funding Status

Our policy is to fund the qualified defined benefit pension plans, as needed, based on tax regulations and funding requirements under federal law, including funding the amounts required by the Employee Retirement Income Security Act of 1974. In addition, it is our intent to contribute sufficient amounts as needed on an actuarial basis to maintain funding targets and to provide for the timely payment of future benefits under these plans. 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 2006 Form 10-K.

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. For further discussion, see Part I, Item 7., Contingent Liabilities, in the 2006 Form 10-K.

We develop estimates of environmental liabilities and related costs based on currently available information, existing technology and environmental regulations. These costs include investigation, monitoring, and remediation. We received regulatory approval to defer and seek recovery of costs related to certain sites and believe the recovery of these costs is probable through the regulatory process. In accordance with SFAS No. 71, Accounting for the Effects of Certain Types of Regulation, we have recorded a regulatory asset for the amount expected to be recovered. We intend to pursue recovery of these environmental costs from our general liability insurance policies, and the regulatory asset will be reduced by the amount of any corresponding insurance recoveries. At March 31, 2007, a cumulative $28.3 million in environmental cost deferrals has been recorded as a regulatory asset, consisting of $21.9 million of costs paid to-date and $6.4 million of accrued estimated future environmental expenditures. 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 (see Note 10, above).

Ratios of Earnings to Fixed Charges

For the three- and 12-months ended March 31, 2007 and the 12-months ended December 31, 2006, our ratios of earnings to fixed charges, computed using the Securities and Exchange Commission method, were 8.86, 3.73 and 3.40, 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.

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, including those of the OPUC and the WUTC, 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;

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implementation by the OPUC of final 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;

risks relating to the creditworthiness of customers, suppliers and financial derivative counterparties;

risks relating to our dependence on a single pipeline transportation provider for natural gas supply;

risks relating to property damage associated with a pipeline safety incident, as well as risks resulting from uninsured damage to our property, intentional or otherwise;

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

risks relating to the execution of our business process redesign;

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;

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 the fair value of pension assets and on pension and other postretirement benefit costs;

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- 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.

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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 Item 7A. in the 2006 Form 10-K, Note 6, 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, 2007 and 2006, notional amounts under these financial hedge contracts totaled $249.8 million and $418.1 million, respectively. If all of the financial hedge contracts had been settled on March 31, 2007, a gain of about $7.1 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, 2008. The $7.1 million unrealized gain is an estimate of future cash flows that are expected to be paid as follows: $5.6 million in the next twelve months and $1.5 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 $7.3 million at March 31, 2007. 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.

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, 2007**	**March 31, 2006**	**Dec. 31, 2006**
AAA/Aaa	$ 3,695	$ 940	$
AA/Aa	3,381	25,465	(40,955)
A/A			
BBB/Baa			
Total	$ 7,076	$ 26,405	$ (40,955)

Item 4. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

As of March 31, 2007, 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 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 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). There have been no changes in our internal control over financial reporting that occurred during our most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

The statements contained in Exhibit 31.1 and Exhibit 31.2 should be considered in light of, and read together with, the information set forth in this Item 4.

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PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

Litigation

For a discussion of certain pending legal proceedings, 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, 2006 which could materially affect our business, financial condition or results of operations. The risks described in the 2006 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.

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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, 2007 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			1,161,100	$ 45,899,916
01/01/07 01/31/07	689	$ 41.51	35,000	(1,505,208)
02/01/07 02/28/07	23,132	$ 42.26	2,500	(109,941)
03/01/07 03/31/07	28,362	$ 43.82	169,200	(7,402,423)
Total	52,183	$ 43.10	1,367,800	$ 36,882,344

(1) During the quarter ended March 31, 2007, 23,960 shares of our common stock were purchased in the open market to meet the requirements of our Dividend Reinvestment and Direct Stock Purchase Plan (DSPP). In addition, 28,223 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, 2007, 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 extended the program through May 31, 2007 and increased the authorization from 2 million shares to 2.6 million shares and increased the dollar limit from $35 million to $85 million. During the three months ended March 31, 2007, 206,700 shares of our common stock were purchased pursuant to this program. Since the program s inception, we have repurchased 1,367,800 shares of common stock at a total cost of $48.1 million through March 31, 2007. In April 2007, the Board extended the program through May 31, 2008 and further increased the authorization from 2.6 million shares to 2.8 million shares and further increased the dollar limit from $85 million to $100 million.

On March 29, 2007, we entered into a Stock Purchase Plan Engagement Agreement with our broker in order to establish a trading plan for our repurchase program that qualifies for the safe harbors provided by Rule 10b-18 and Rule 10b5-1 under the Exchange Act. The agreement expires on May 31, 2007, but management may elect to enter into new agreements in the future to achieve the objectives of our repurchase program.

On February 27, 2007, we commenced a voluntary oddlot program through Georgeson Inc. which offered shareholders holding accounts with less than 100 shares of common stock the opportunity to either sell their shares or purchase an additional number of shares to round up to 100 shares of common stock in the account at the average closing price of our common stock over the offering period. As of the end of the initial offering period on March 30, 2007, a net of 7,363 shares were made available for repurchase by us at the average closing price of $44.54 per share. These amounts are not reflected in the above table as the settlement date occurred on April 19, 2007. The extension period under the program expired on April 25, 2007.

Item 6. EXHIBITS

See Exhibit Index attached hereto.

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SIGNATURE

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

	NORTHWEST NATURAL GAS COMPANY (Registrant)
Dated: May 4, 2007	/s/ Stephen P. Feltz Stephen P. Feltz Principal Accounting Officer Treasurer and Controller

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NORTHWEST NATURAL GAS COMPANY

EXHIBIT INDEX

To

Quarterly Report on Form 10-Q

For Quarter Ended

March 31, 2007

Document	Exhibit Number
Statement re: Computation of Per Share Earnings	11
Computation of Ratio of Earnings to Fixed Charges	12
Certification of Principal Executive Officer Pursuant to	31.1
Rule 13a-14(a)/15d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002	
Certification of Principal Financial Officer Pursuant to	31.2
Rule 13a-14(a)/15d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002	
Certification of Principal Executive Officer and Principal Financial Officer	32.1
Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	